

**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-21860

QUALIFICATIONS  
  
AND  
  
DIRECT TESTIMONY  
  
OF  
  
MARCO A. BRUZZANO

**DTE ELECTRIC COMPANY**  
**QUALIFICATIONS AND DIRECT TESTIMONY OF MARCO A. BRUZZANO**

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

2     A1.    My name is Marco Bruzzano. My business address is One Energy Plaza, Detroit,  
3            Michigan 48226. I am employed by DTE Energy Corporate Services LLC, a  
4            subsidiary of DTE Energy Company (DTE).

6     **Q2.    On whose behalf are you testifying?**

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

9     **Q3.    What is your educational background?**

10    A3.    I hold Bachelor of Science, with honors, and Master of Science degrees in  
11            Mechanical Engineering from the Georgia Institute of Technology. I also hold an  
12            MBA from Duke University, where I graduated with distinction.

14    **Q4.    What is your work experience?**

15    A4.    Immediately prior to joining the Company, I was a principal with Booz Allen  
16            Hamilton's Energy & Utilities practice. I also worked as an engagement manager  
17            with McKinsey & Company, primarily in the Electric Power & Natural Gas and  
18            Petroleum practices. During my consulting career, I led projects for large utilities,  
19            major international oil companies and independent power producers on a broad  
20            range of strategic and operational topics. I started my career with Chevron U.S.A.  
21            as a design engineer and planning analyst.

23            I joined DTE Electric in 2008 as a director in the Corporate Strategy group. In 2013,  
24            I was appointed vice president, Corporate Strategy, and assumed overall  
25            responsibility for supporting DTE Energy's business units on priority strategic

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1 initiatives. In 2016, I was appointed to the role of vice president, Distribution  
2 Operations, where one of my primary responsibilities was developing the  
3 Company's multi-year Distribution Investment & Maintenance Plan and the  
4 associated regulatory filings. In 2021, I was appointed to my current role of senior  
5 vice president, Regulatory Affairs.

6

7 **Q5. What are your current duties and responsibilities?**

8 A5. My primary responsibility is to manage the regulatory proceedings that come before  
9 the Michigan Public Service Commission.

10

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

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

14 U-20162 DTE Electric 2018 General Rate Case

15 U-20561 DTE Electric 2019 General Rate Case

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1 **Purpose of Testimony**

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

3 A7. The purpose of my testimony is to:

- 4 • Review the methodology used to develop the Company's projected
- 5 revenue deficiency;
- 6 • Provide a summary of the Company's electric rate case and the
- 7 resulting customer benefits;
- 8 • Describe the importance of timely cost recovery to support the
- 9 investments needed to achieve these benefits.

10

11 **Q8. How is your testimony organized?**

12 A8. My testimony is organized in three sections:

- 13 • Part I: Rationale for the filing
- 14 • Part II: Case summary
- 15 • Part III: Importance of timely cost recovery

16

17 **Part I: Rationale for the filing**

18

19 **Q9. Why has DTE Electric filed this general rate case at this time?**

20 A9. DTE Electric strives to provide safe, reliable, clean, and affordable electric  
21 service to its customers. The Company has undertaken a major capital  
22 investment program to improve the reliability and resiliency of the  
23 distribution system and sustain the reliability of its generation fleet while  
24 also moving toward cleaner sources of generation. The Company's current  
25 authorized rates would not provide DTE Electric with adequate revenues to



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1 make necessary infrastructure and generation investments while also  
2 providing a reasonable opportunity to earn a fair return on equity and  
3 maintain a position of financial health.

4

5 **Q10. What are the measures used to determine the Company's financial**  
6 **health?**

7 A10. DTE Electric's financial health requires a reasonable opportunity to earn its  
8 cost of capital, a well-balanced capitalization structure, that the Company  
9 maintain its A/Aa3/A+ credit ratings for senior secured debt from the three  
10 major rating agencies, and the ability to pay a reasonable dividend. These  
11 preconditions are necessary to ensure DTE Electric has full access to capital  
12 markets at reasonable rates, terms, and conditions regardless of business  
13 cycle timing or industry conditions, as discussed by Company Witnesses  
14 Nelson and Lepczyk.

15

16 **Q11. Why is the Company's financial health important for customers?**

17 A11. Company Witness Lepczyk discusses that without full access to capital  
18 markets at reasonable terms and conditions, the cost of providing utility  
19 services can increase. Increased costs can lead to inadequate funding for the  
20 capital and maintenance programs that would, over time, result in the  
21 deterioration of DTE Electric's distribution and generation infrastructure,  
22 ultimately resulting in reduced system reliability and service quality.

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1   **Q12.   What rate relief is DTE Electric requesting in this case?**

2   A12.   As calculated by Company Witness Vangilder, DTE Electric projects a  
3           revenue shortfall of \$574.1 million for the January 1, 2026 through  
4           December 31, 2026 projected test year. As supported by the Company's  
5           witnesses in this case, factors contributing to this shortfall are the revenue  
6           requirement associated with increased investments made in plant and their  
7           associated depreciation and property tax increases, as well as the impact of  
8           inflation and other cost increases on DTE Electric's operations and  
9           maintenance (O&M) and costs.

10

11   **Q13.   Can you describe the methodology the Company is using to support its**  
12           **projected test year positions and its recommendations in this case?**

13   A13.   Yes. DTE Electric has used actual historical data as the basis for most  
14           estimated cost levels for the projected test year. These historical costs were  
15           then adjusted for the impact of inflation. As has been DTE Electric's  
16           practice in prior rate cases, certain other costs reflect specific estimates or  
17           projections where the general impact of inflation alone would be  
18           insufficient to capture known changes.

19

20           All cost components are explained and supported by other Company  
21           witnesses. The witnesses, along with the scope of their testimony, are  
22           introduced by Company Witness Leslie.

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1 **Q14. What historical and projected test year periods are being used by DTE**  
2 **Electric for purposes of calculating its projected revenue deficiency?**

3 A14. The historical test year used by DTE Electric is the calendar year ended  
4 December 31, 2023. This 12-month period was then normalized and  
5 adjusted for known and measurable changes, as supported by the  
6 Company's witnesses in this case, to arrive at the Company's January 1,  
7 2026 through December 31, 2026 projected test year.

8  
9 **Q15. Are there other recovery mechanisms being requested in this rate case?**

10 A15. Yes. Through the testimony of Company Witness Willis, the Company is  
11 also proposing an extension of the Distribution Infrastructure Recovery  
12 Mechanism (IRM), originally approved by the Commission in Case No. U-  
13 21297 and updated in Case No. U-21534, for the period 2027 to 2029.

14  
15 **Part II: Case Summary**

16  
17 **Q16. Can you provide an overview of the Company's proposals in this case?**

18 A16. Yes. The Company is continuing its multi-year journey aimed at providing  
19 safe, reliable, and increasingly clean electric service by making necessary  
20 capital investments in its distribution grid and power generation and energy  
21 storage assets. These investments, which will be described in detail by the  
22 Company's witnesses, include:

- 23
  - Strategic investments in the electric distribution grid designed to
  - 24 significantly improve reliability and meet the Company's goal of
  - 25 reducing outage frequency by 30% and outage duration by 50% by

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- 1 the end of 2029. The Company's goal of improving reliability is
- 2 well-aligned with the objectives set forth by the Michigan Public
- 3 Service Commission in the Service Quality & Reliability Standards
- 4 (SQRS) and in the Commission's order in the Financial Incentives
- 5 and Disincentives docket<sup>1</sup>.
- 6 • Investments in the Company's generation portfolio including the
- 7 conversion of the Belle River Power Plant from coal to natural gas
- 8 and the development of the Trenton Channel Battery Storage
- 9 project. These investments, which support reliable plant operations
- 10 and cleaner sources of generation, were included in the Company's
- 11 approved 2022 Integrated Resource Plan (IRP) Settlement
- 12 Agreement in Case No. U-21193. The Trenton Channel Battery
- 13 Storage project supports the State's Clean Energy Standard targets<sup>2</sup>
- 14 and demonstrates progress toward the Company's and State's
- 15 energy storage target<sup>3</sup>.
- 16 • Investments in the Fermi 2 Nuclear Power Plant which has been
- 17 licensed by the Nuclear Regulatory Commission to provide carbon-
- 18 free power through at least 2045; these investments focus on
- 19 ensuring the continued safe and reliable operation of the plant.
- 20 • Investments in information technology (IT) infrastructure focused
- 21 on cybersecurity for grid reliability and on the reliability and
- 22 resiliency of the Company's IT assets.

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<sup>1</sup> MPSC Case No. U-21400 February 27, 2025 Order

<sup>2</sup> As detail in MCL460.1051, 80% clean energy portfolio in 2035 through 2039 and 100% in 2040 and each year thereafter

<sup>3</sup> Sections 101 and 103, MCL 460.1101(1)-(9) establish a statewide energy storage target of 2,500 megawatts (MW)

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1 The Company is also proposing to continue execution of the elements of its  
2 Transportation Electrification Plan (TEP) that were first approved in Case  
3 No. U-21534 as discussed by Company Witness Foley. Through the TEP,  
4 the Company seeks to support the State's MI Healthy Climate Plan and MI  
5 Future Mobility Plan by directing more than \$130 million between 2025-  
6 2028 toward transportation electrification through its charger rebates,  
7 education and outreach initiatives, and the Emerging Technology Fund.

8

9 **Q17. Given the significant focus on electric distribution reliability in the**  
10 **state<sup>4</sup>, can you provide additional insights into the benefits customers**  
11 **will receive from the projected distribution investments?**

12 A17. Yes. As explained in more detail by the Company's Distribution Operations  
13 witnesses in this case (Witnesses Chiu, Kryscynski, Stowe, De Stigter, Hill,  
14 Rademacher, Robinson, and Steudle), DTE Electric is strengthening,  
15 rebuilding, and using technology to create a smarter, more resilient and  
16 reliable grid. These investments will lead to significant improvements in  
17 reliability, as discussed in greater detail by these witnesses.

18

19 **Q18. Are the Company's projected distribution investments in the current**  
20 **case consistent with achieving these objectives?**

21 A18. Yes. The Utility Distribution Audit of DTE Energy (Audit or Distribution  
22 Audit) performed by Liberty Consulting, an independent third-party

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<sup>4</sup> As evidenced by the DTE Electric Audit Report filed in Case No. U-21305 and the February 2025 Order in Case No. U-21400

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1 engaged by the MPSC, highlights on pages 24 and 25 that the Company  
2 utilizes an appropriate methodology for selecting its proposed investments.

3 “We found DTE’s modeling used for evaluating, comparing, and  
4 prioritizing reliability initiatives, sound. DTE’s Global  
5 Prioritization model, which systematically compares and  
6 evaluates competing system improvement and reliability-  
7 enhancing projects and programs across 10 important  
8 improvement dimensions, seems a balanced and logical  
9 application of the “best fit, most reasonable cost” economic  
10 approach to investment optimization. Its application at DTE is  
11 consistent with other utility strategic investment good practices  
12 that Liberty has experienced.”

13

14 Utility Distribution Audit of DTE Energy

15 Part Two Chapter I

16 (MPSC Case No. U21305)

17

18 **Q19. Has the Company considered the recommendations of the Distribution**  
19 **Audit in developing the portfolio of investments presented in this case?**

20 A19. Yes. This is discussed by Company Witness Chiu and other Distribution  
21 witnesses.

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1   **Q20. What value will be realized through the Company's projected**  
2       **Distribution investments?**

3   A20. The investments will substantially improve DTE Electric customers'  
4       service quality and unlock economic value for customers and for the state.  
5       The forecasted improvements in reliability are described in detail by  
6       Company Witness Kryscynski. In addition, the publicly available  
7       Interruption Cost Estimator (ICE) Calculator, developed by the Lawrence  
8       Berkeley National Laboratory, provides an approach to estimate the value  
9       that might be realized through improved electric system reliability. Based  
10      on the ICE Calculator, which is described in greater detail by Company  
11      Witness De Stigter, the forecasted reliability improvements could generate  
12      more than an estimated \$20 billion of positive economic impact. Realizing  
13      such estimated benefits is dependent upon achieving improved reliability  
14      through continued investment in the Company's grid, enabled by the timely  
15      cost recovery of capital expenditures, as discussed in Part III of my  
16      testimony.

17

18   **Q21. Does the Company's ongoing investment provide any other benefits to**  
19       **its region and the State?**

20   A21. Yes. DTE Electric has an important positive economic impact on the  
21       communities it serves. DTE Electric is one of the largest employers in  
22       Southeast Michigan with over 4,800 employees. DTE Energy is a founding  
23       member of Pure Michigan Business Connect, an initiative that encourages  
24       businesses to buy from Michigan suppliers and connects local companies  
25       with in-state opportunities. In 2024, DTE Energy spent \$3.3 billion with

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1 1,808 businesses in 73 Michigan counties. More than 80 percent of DTE's  
2 supplier spending in 2024 occurred within the Company's service territory.  
3 Sixty-eight cents of every dollar DTE spends externally goes to a Michigan-  
4 based company. Through its investments, DTE Electric supports job growth  
5 opportunities and provides continuing and incremental tax revenue for our  
6 local communities. In the historical test year, DTE Electric paid  
7 approximately \$300 million in property taxes to Michigan communities.

8

9 **Q22. What impact would this rate case have on residential customers' bills?**

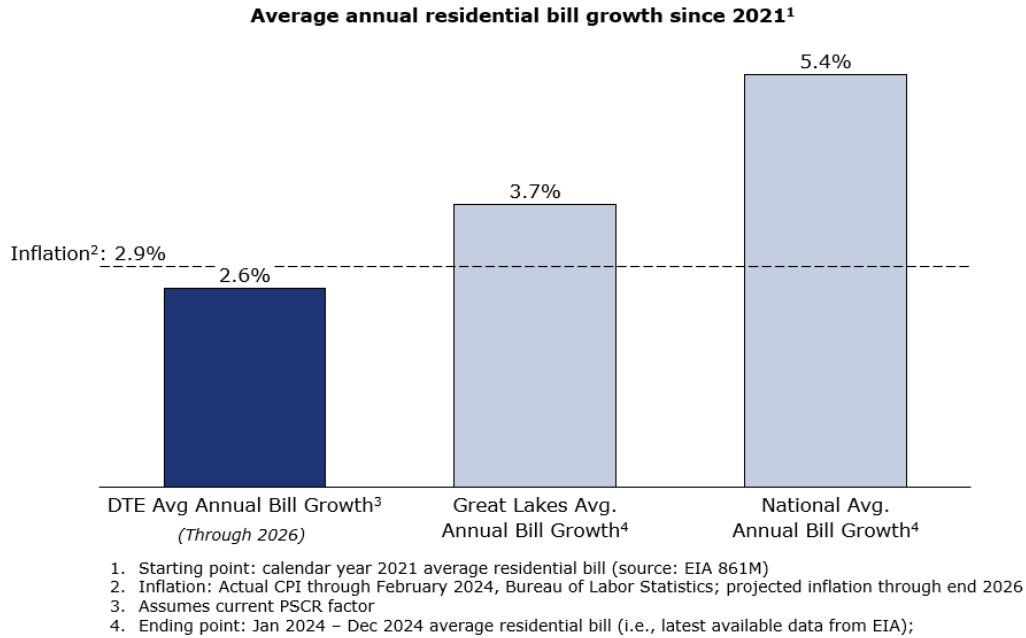
10 A22. Rate relief consistent with the request in this case would result in an increase  
11 of 44 cents per day for the average residential customer. This would result  
12 in an average yearly bill increase since 2021 of 2.6%, which is below the  
13 rate of inflation and below the average increases experienced by other  
14 utilities in the Great Lakes region and at the national level, as seen in Figure  
15 1 below.



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**Figure 1 Average Residential Bill Growth<sup>1</sup>**



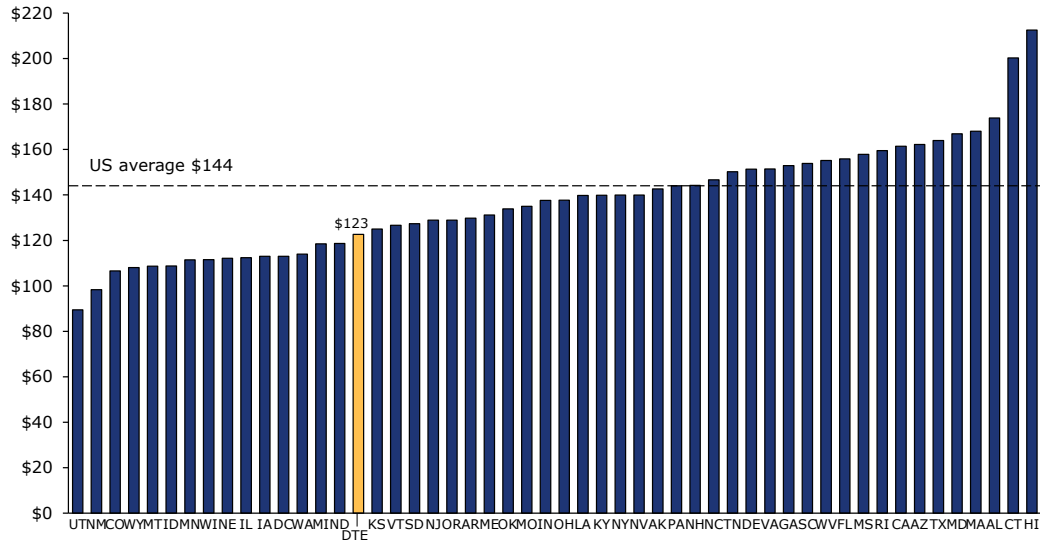
2

3 **Q23. How do the Company's current residential customer bills compare to**  
 4 **the rest of the country?**

5 A23. Based on data from the Energy Information Administration (EIA) and as  
 6 captured in Figure 2, the Company's average residential customer bill was  
 7 14.5% below the national average in 2024.

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**Figure 2 Average 2024 Monthly Residential Electric Bills**

Source: EIA form 861M (the 12-month average is the average monthly residential bill from January 2024 to December 2024)

2

3 **Q24. Does the Company help mitigate the impact of bill increases on its most**  
 4 **vulnerable low-income customers?**

5 A24. Yes. Recognizing that any rate increase may be impactful to its most  
 6 vulnerable low-income customers, the Company takes an active leadership  
 7 role in advocating for support for these customers. Over the last several  
 8 years, the Company has led initiatives at both the State and Federal levels  
 9 to expand access and funding for its low-income customers, as discussed by  
 10 Company Witness Sparks. In his testimony, he describes the support for  
 11 offered by the Company's Low Income Self Sufficiency Plan (LSP)  
 12 program, advocates for a continuation of our Low-Income Assistance (LIA)  
 13 Credits and outlines the Payment Stability Plan (PSP) recommendation (as  
 14 referenced in MPSC Case No. U-20929).

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1 **Part III: Importance of timely cost recovery**

2

3 **Q25. How will the outcome of this case impact the Company's ability to**  
4 **achieve the objectives you outlined earlier in your testimony?**

5 A25. The Company requires adequate revenues that support timely cost recovery  
6 to meet these objectives. Without adequate revenues, the Company will be  
7 challenged in executing the investments described in this case.

8

9 **Q26. How does the Company define timely cost recovery?**

10 A26. Timely cost recovery matches revenues with the incurrence of costs. This  
11 structure allows customer rates to reflect the actual costs expected to be  
12 incurred by the Company at the time they will be incurred. These costs are  
13 driven by a combination of capital investments, O&M costs, and financing  
14 costs.

15

16 **Q27. Can you describe how disallowances of capital investments can impact**  
17 **timely cost recovery?**

18 A27. The disallowance of capital investments creates "regulatory lag" if the  
19 Company does in fact incur the capital costs which were disallowed.  
20 Regulatory lag is comprised of the following cost elements:

- 21 • Depreciation expense designed to recover the cash cost of the  
22 investment over a predefined period.
- 23 • Property taxes associated with the investment.

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- 1           • The financing cost of the investment deriving from the interest  
2           expense associated with borrowed funds and the allowed returns on  
3           invested equity.

4  
5       Taken together, and adjusted for the impact of income taxes, these costs  
6       become the revenue requirement of the investments. When proposed  
7       investments are disallowed, if the Company does incur the capital  
8       expenditures it will not recover the costs described above in a timely  
9       manner. This “regulatory lag” represents foregone cost recovery of the  
10      Company’s investment.

11  
12      Even if the investment is ultimately included in rate base through a  
13      subsequent rate case, the Company cannot recover any of the costs it  
14      incurred between the time it made the investment and when the investment  
15      was approved to be recovered. For example, the Company cannot recover  
16      any cash interest expense or property taxes that it paid in support of an  
17      investment prior to the investment being approved for recovery. And a  
18      portion of the cash cost of the investment will also not be recovered because  
19      of the foregone depreciation expense. Thus, the regulatory lag associated  
20      with disallowance of otherwise reasonable and prudent investments results  
21      in *lost* recovery.

22

23   **Q28. Is the Company experiencing regulatory lag from prior investments**  
24   **that were not included in rates?**

25   A28. Yes. To illustrate this, I offer an example below.

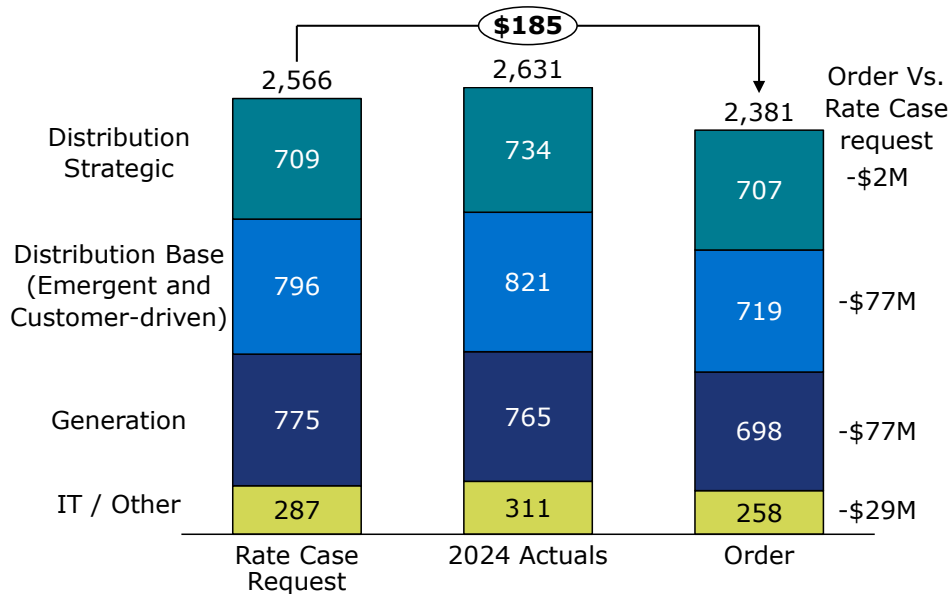
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1 In the January 23, 2025 Order in Case No. U-21534, the Commission  
2 disallowed approximately \$185 million of investments that were included  
3 in the Company's projections for 2024 (the bridge year in the last case). As  
4 shown below in Figure 3, the Company's actual 2024 expenditures were  
5 slightly above the bridge year projection contained in the rate case.  
6 However, because \$185 million of the projected capital was disallowed,  
7 the Company will not be able to recover the costs associated with this  
8 investment throughout all of 2025. Even if the investments are eventually  
9 included in rate base, the financial loss from unrecovered depreciation,  
10 property tax, and interest expense, along with foregone equity returns  
11 during the intervening period between cases, is permanent.

12

13

**Figure 3 : 2024 Capital Investments**



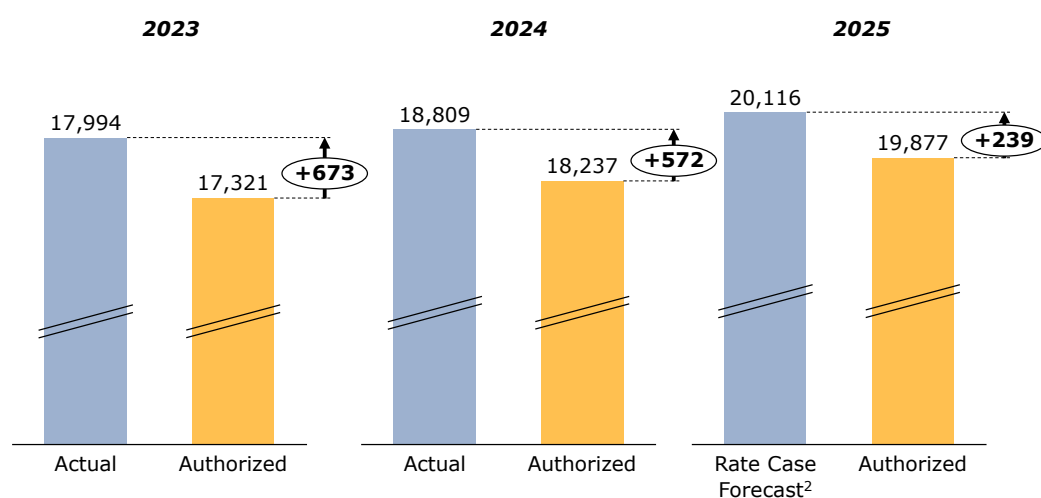
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1 **Q29. Has there been a pattern of the Company incurring regulatory lag?**

2 A29. Yes. As illustrated in Figure 4 below, the Company has been carrying a  
3 consistently higher Net Plant In-Service balance than what has been  
4 included in rate base, leading to persistent regulatory lag.

5

6 **Figure 4 Average Electric Net Plant In-Service<sup>1</sup> (\$ billion)**



1. Does not include Plant Held For Future Use, CWIP, or Monroe Reg Asset Reclass

2. As reflected in U-21860 bridge period exhibits

7

8 **Q30. Is it sustainable for the Company to absorb regulatory lag for**  
9 **disallowed capital without implementing offsetting reductions in other**  
10 **projected capital expenditures?**

11 A30. No. The Company's ability to absorb regulatory lag is not limitless because  
12 its effects are cumulative. The potential of persistent regulatory lag can lead  
13 to reductions in future capital expenditures or temporary O&M reductions  
14 to address revenue shortfalls. This has the potential to result in negative  
15 effects on customers.

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1   **Q31. Are there particular capital disallowances you are concerned with?**

2   A31. Yes. While any capital disallowance can introduce uncertainty in the  
3       Company's ability to execute investments, disallowances of capital  
4       expenditures which the Company has little choice but to incur will lead to  
5       negative financial impacts that the Company may need to address by  
6       reducing other expenditures. There were two sources of capital  
7       disallowance from Case No. U-21534 which are of particular concern to the  
8       Company. As will be discussed in greater detail by other witnesses in the  
9       case, the disallowances described below could result in persistent  
10      underfunding of investments:

- 11           • The application of the Association for the Advancement of Cost  
12           Engineering (AACE) uncertainty range for capital cost estimates  
13           in Case No. U-21534 and prior cases, which resulted in significant  
14           disallowances of IT, Energy Supply and Nuclear<sup>5</sup>, even for  
15           projects otherwise deemed reasonable and prudent. Company  
16           Witness Ludlow will describe why the application of the AACE  
17           methodology in such a manner has a high likelihood of resulting  
18           in underfunding, especially as the Commission has directed the  
19           Company to not include normal project contingency in its cost  
20           projections.
- 21           • The decision in Case No. U-21534 to not allow the use of  
22           constant-dollar averaging (i.e., applying inflation to historical  
23           expenditures) in the calculation of average emergent and other

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<sup>5</sup> Case No. U-21534 Jan 23, 2025 Order at pgs. 42-45, 56-58, 183-187.

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1 base distribution capital cost<sup>6</sup>, even in the face of very high  
2 inflationary pressures experienced by the Company in the last  
3 several years, will result in underfunding these expenditures.  
4 Company Witness Lyons will describe why the use of constant-  
5 dollar averaging for costs incurred in prior years is both  
6 appropriate and common practice.

7  
8 These types of disallowances are especially concerning because the  
9 Company has no choice but to incur the costs as they occur, either because  
10 a project is already in progress and will incur expenditures at or above  
11 those projected in the case, or because system repairs need to be made at  
12 costs beyond those authorized in rates, or because of the need to execute  
13 customer-requested attachments, resulting in a negative financial impact  
14 from the costs associated with regulatory lag.

15

16 **Q32. What actions might the Company need to take to mitigate the negative**  
17 **financial impact of regulatory lag?**

18 A32. One way to absorb the unrecovered depreciation and the other expenses  
19 associated with regulatory lag is to reduce capital expenditures in other  
20 areas. That is, to match future capital spending to the level the Commission  
21 authorized in a rate case order by adjusting the areas of investment in a way  
22 that considers areas of spend that cannot be deferred.

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<sup>6</sup> Case No. U-21534 Jan 23, 2025 Order at pgs. 68-75.



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1   **Q33. Can you illustrate what adjustments to capital expenditures would be**  
2       **needed to absorb the financial impact of disallowed capital which the**  
3       **Company has no choice but to incur?**

4   A33. The amount of investment that may need to be re-timed to future years  
5       depends on whether disallowances occur in the *bridge year* or the *projected*  
6       *test year*.

7  
8       For example, \$200 million of *bridge year* capital investment requires  
9       approximately \$28 million of revenue requirement in the *projected test*  
10      *year*. This means that the disallowance of \$200 million of invested capital  
11      in a bridge year would leave the Company with \$28 million of unrecovered  
12      costs in the projected test year if it did in fact make these investments in the  
13      bridge year. This is very similar to the situation I described above: the  
14      disallowances of 2024 capital investment have resulted in unrecovered costs  
15      in 2025 which the Company must absorb because the Company did in fact  
16      make the investments it projected in the case.

17  
18      *Projected test year* capital has a revenue requirement of approximately \$11  
19      million in the projected test year for each \$200 million of capital because of  
20      lower depreciation and property tax expense associated with capital in the  
21      projected test year. Thus, capital disallowances in the *bridge year* have  
22      approximately 2.5 times the revenue impact of disallowances in the  
23      *projected test year*<sup>7</sup>. Therefore, for every dollar of invested but disallowed  
24      *bridge year* capital, the Company must consider adjusting its capital plans

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<sup>7</sup> 28 / 11 = 2.5

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1 by two and half dollars of *projected test year* capital investment to ensure  
2 adequate revenues to cover costs. In summary:

- 3 • \$200 million disallowance in the bridge year could necessitate the  
4 reduction of \$500 million of forward test year investment.
- 5 • \$200 million of forward test year disallowance could necessitate the  
6 reduction of \$200 million in the forward test year itself.

7

8 **Q34. Are there other disallowances that could lead the Company to have to**  
9 **retime planned investments?**

10 A34. Yes. O&M disallowances for inflation or for other known and measurable  
11 expenses can also result in the Company not recovering its actual costs if  
12 the Company has no choice but to incur the expenditures. Disallowed but  
13 unavoidable O&M expenses in the projected test year represent a “one-to-  
14 one” reduction in revenue deficiency. The impact is such that \$10 million  
15 of disallowed but unavoidable O&M could lead to the need to defer \$180  
16 million of forward test year capital<sup>8</sup>.

17

18 **Q35. Can you provide an example of when the Company has had to take**  
19 **actions to manage through a period of financial pressure caused by**  
20 **regulatory lag and other factors?**

21 A35. Yes. In 2023, many of the conditions described above were encountered at  
22 DTE Electric, leading to an extremely difficult year financially. The  
23 Company faced significant regulatory lag because of a challenging rate case

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<sup>8</sup> 10 / (11 / 200) = 180

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1 outcome at the end of 2022<sup>9</sup>, intense storms, a warmer than normal winter  
2 and a cooler than normal summer.

3

4 **Q36. Did the Company reduce its 2023 capital expenditures in the face of this**  
5 **financial pressure?**

6 A36. No. Even though the Company faced capital disallowances from the  
7 November 2022 Order and high capital costs from the storms early in the  
8 year, it executed capital investments that were aligned with the levels  
9 proposed in the case.

10

11 **Q37. Why did the Company not adjust its capital plans in 2023?**

12 A37. The Company believes that the capital investments it projects in any rate  
13 case are reasonable, prudent and in the best interest of its customers. This is  
14 especially true for investments in the electric grid because customers  
15 deserve improved reliability and because this objective is consistent with  
16 the Commission's own goals.

17

18 More specifically to investments aimed at improving the grid, in 2023 the  
19 Company chose to invest approximately \$780 million in Distribution  
20 Strategic investments despite the Order in Case No. U-20836 authorizing  
21 approximately \$490 million. The Company chose to do so in part because  
22 of the Commission's rationale for some of the Distribution Strategic  
23 disallowances:

---

<sup>9</sup> MPSC Case No. U-20836

Line  
No.

1 “... DTE Electric has yet to demonstrate that it is capable of  
2 spending capital even approaching the levels proposed for 2022  
3 and 2023... Indeed, DTE Electric’s own exceptions state that it  
4 “is not always possible . . . to meet strategic investment goals .  
5 . . when there is an overspend in emergent [capital].”

6 As such, until DTE Electric demonstrates its ability to actually  
7 spend the dollars authorized for strategic capital, the  
8 Commission remains unpersuaded that allowing for the full  
9 amounts sought by the company to be included in rates is  
10 reasonable. In the meantime, the Commission notes that the  
11 company has the ability to spend above the level of capital  
12 approved in this case and may recover the amount in a future  
13 rate case after the spend is proven to be reasonable and  
14 prudent.”<sup>10</sup>

15  
16 Given this feedback and the importance of timely recovery of costs  
17 associated with projected investments, the Company felt it was important to  
18 demonstrate its ability to invest at projected levels, especially because  
19 seeking to recover already invested amounts in future rate cases is not a  
20 viable long-term strategy to make the improvements in reliability that are  
21 necessary to meet the SQRS, the targets set forth in the Financial Incentives  
22 and Disincentives order and to implement the recommendations of the  
23 Distribution Audit.

---

<sup>10</sup> MPSC Case No. U-20836 Order, pg. 80

Line  
No.

1   **Q38. Did the Company seek to implement other directives from the**  
2           **Commission with respect to investments in the distribution grid in**  
3           **2023?**

4   A38. Yes. In the same order described above, the Commission also stated:

5  
6           “The Commission cannot stress enough its expectation that  
7           DTE Electric will invest the amounts approved for strategic  
8           capital improvements and not shift them to other categories  
9           such as emergent replacement and other reactive  
10          spending.”<sup>11</sup>

11  
12       Despite incurring approximately \$520 million of emergent spend in 2023  
13       against the approximately \$320 million authorized in rates, the Company  
14       did not shift funds that were approved for strategic investments. In fact,  
15       DTE Electric did not shift funds from other areas of the Company either,  
16       thus experiencing the significant difference in the amount of actual net-  
17       plant-in-service compared to what was included in rates, as illustrated in  
18       Figure 4 above. As I have described throughout my testimony, this  
19       difference led to substantial financial pressure from the regulatory lag of  
20       costs the Company incurred in 2023 but did not recover in rates.

---

<sup>11</sup> MPSC Case No. U-20836, pg. 76

Line  
No.

1   **Q39. What actions did the Company take in 2023 to allow it to sustain its**  
2       **capital investments and mitigate the impact of this regulatory lag?**

3   A39. To mitigate the significant revenue shortfall in 2023, while also maintaining  
4       the financial health of the Company and executing the capital investments  
5       the Company had determined were in the best interest of customers, DTE  
6       Electric took a number of temporary, unsustainable measures to reduce its  
7       O&M expenditures. These reductions are discussed by the Company's  
8       individual O&M witnesses in this case.

9

10   **Q40. Might the Company need to adjust capital investments in the future in**  
11       **the face of insufficient cost recovery?**

12   A40. Yes. The Company will always seek to pursue the investments that provide  
13       customer benefits when it has the financial resources to do so. However,  
14       while the Company has absorbed regulatory lag along with other financial  
15       pressures in the past, it may not be able to do so in the future without  
16       retiming capital expenditures. As further discussed by Company Witness  
17       Sheilendranath of the Brattle Group, the lack of timely cost recovery could  
18       lead the Company to have to scale back capital investments, leading to  
19       reduced service quality over time.

20

21   **Q41. Does this complete your direct testimony?**

22   A41. 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-21860

QUALIFICATIONS  
  
AND  
  
DIRECT TESTIMONY  
  
OF  
  
JOYCE E. LESLIE

**DTE ELECTRIC COMPANY**  
**QUALIFICATIONS AND DIRECT TESTIMONY OF JOYCE E. LESLIE**

Line  
No.

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

2   A1.   My name is Joyce E. Leslie, Director (she/her/hers). My business address is One  
3       Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate  
4       Services LLC, a subsidiary of DTE Energy Company as a Director, Regulatory  
5       Affairs.

6  
7   **Q2.   On whose behalf are you testifying?**

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

9  
10   **Q3.   What is your educational background?**

11   A3.   I graduated from Central Michigan University with a Bachelor of Science Degree  
12       in Business Administration, Accounting, and a minor in Economics. I received my  
13       master's degree in Business Administration from the University of Michigan.

14  
15   **Q4.   What is your work experience?**

16   A4.   I began my career with Deloitte & Touche in the Auditing division as a Senior  
17       Auditor and worked there for two and a half years. I began working for MCN  
18       Energy Group, Inc. in 1996, as an accountant prior to its merger with DTE Energy.  
19       Over the years, I held a number of positions with increasing leadership  
20       responsibilities in areas that include Energy Trading, Enterprise Risk Management,  
21       Controller for Gas Financial Support, Investor Relations, Electric Strategy and  
22       Special Projects, and Business Planning and Development.

23  
24   **Q5.   Do you have any professional certifications?**



Line  
No.

1 A5. Yes, I do. I am a licensed Certified Public Accountant (CPA) within the State of  
2 Michigan, having earned my professional certification in 1995, while employed by  
3 Deloitte & Touche. I am also a Financial Risk Manager (FRM) and was certified  
4 in 2008 by the Global Association of Risk Professionals (GARP).

5

6 **Q6. What are your current duties and responsibilities?**

7 A6. I am responsible for managing the Company's electric activities at the Michigan  
8 Public Service Commission (MPSC or Commission) and at the Federal Energy  
9 Regulatory Commission (FERC). My team handles case management for the  
10 Company's regulatory and compliance filings, as well as regulatory strategy  
11 pertinent to the Company's electric utility.

12

13 **Q7. Have you previously sponsored testimony before the MPSC?**

14 A7. Yes. I sponsored testimony in the following DTE Electric cases:

15 U-20561 DTE Electric 2019 General Rate Case

16 U-21193 DTE Electric 2022 Integrated Resource Plan Filing

Line  
No.

1 **Purpose of Testimony**

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

3 A8. The purpose of my testimony is to address the following:

- 4 ○ Introduction of witnesses
- 5 ○ Corporate memberships and costs included for ratemaking
- 6 ○ Voluntary Separation Incentive Plan (VSIP)
- 7 ○ Outage credit cost recovery

8

9 **Q9. Are you sponsoring any exhibits in this proceeding?**

10 A9. Yes. I am supporting the following exhibits:

| 11 | <u>Exhibit</u> | <u>Schedule</u> | <u>Description</u>    |
|----|----------------|-----------------|-----------------------|
| 12 | A-27           | Q1              | Corporate Memberships |
| 13 | A-30           | T1              | VSIP Net Savings      |

14

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

16 A10. Yes, they were.

17

18 **Introduction of Witnesses**

19 **Q11. How will the Company present evidence in support of its requested relief in**  
20 **this case?**

21 A11. The Company will present its case through 34 witnesses, including myself, as  
22 described below and shown in Table 1.

Line  
No.

1

**Table 1      Witness Introductions**

|    | <b>Witness</b>         | <b>Scope of Testimony</b>                                                                                                                                                                      |
|----|------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| 1  | Marco A. Bruzzano      | Summary and overview of DTE Electric Rate Case                                                                                                                                                 |
| 2  | Akarsh Sheilendranath  | Under recovery of capital expenditures for needed investments and the effect on the Company's regulatory and business risks                                                                    |
| 3  | William H. Ludlow      | Cost forecasts and conformance with industry standards for cost estimation                                                                                                                     |
| 4  | Tim S. Lyons           | Constant dollar averaging to develop cost forecasts                                                                                                                                            |
| 5  | Bill Chiu              | Distribution - Overview of DTE Electric's planned distribution grid investments                                                                                                                |
| 6  | Allen J. Kryscynski    | Distribution - O&M, the Global Prioritization and Reliability Models and approach to Environmental Justice in Distribution planning                                                            |
| 7  | Joseph E. Robinson     | Distribution - Strategic capital pillar of Infrastructure Resilience and Hardening                                                                                                             |
| 8  | Ryan M. Stowe          | Distribution - Strategic capital pillar of Infrastructure Redesign and Modernization                                                                                                           |
| 9  | Stephen P. Rademacher  | Distribution - Strategic capital pillar of Technology & Automation                                                                                                                             |
| 10 | Jason De Stigter       | Distribution - Benefit-cost analysis for: 1) Pole and Pole Top Maintenance & Modernization, 2) Strategic Undergrounding, 3) Distribution Automation, and 4) Grid Automation Telecommunications |
| 11 | Brian L. Hill          | Distribution - Base Capital programs, Emergent Replacements and Customer Connections, Relocations & Other                                                                                      |
| 12 | Rachel C. Steudle      | Distribution - Tree Trimming Program                                                                                                                                                           |
| 13 | Christopher J. Hartley | Community Lighting Capital Expenditures and O&M                                                                                                                                                |
| 14 | Margaret E. Guillaumin | Energy Supply Operations Performance, Generation Capital Expenditures and O&M                                                                                                                  |
| 15 | Robert J. Lee          | Environmental Regulations                                                                                                                                                                      |
| 16 | David C. Milo          | Fuel Supply and Midwest Energy Resources Company's Capital Expenditures and O&M                                                                                                                |
| 17 | Shawn D. Burgdorf      | Capacity-related generation costs and projected wholesale market energy sales revenue, net of fuel                                                                                             |

Line  
No.

|    | <b>Witness</b>        | <b>Scope of Testimony</b>                                                                                         |
|----|-----------------------|-------------------------------------------------------------------------------------------------------------------|
| 18 | Jeffery C. Davis      | Nuclear Capital Expenditures and O&M                                                                              |
| 19 | Steve B. Ambrose      | Information Technology Capital Expenditures and O&M                                                               |
| 20 | Neal T. Foley         | Electric Marketing Capital Expenditures and O&M including Transportation Electrification Plan and Merchant Fees   |
| 21 | Timothy J. Lepczyk    | Capital Structure and Long and Short-term Debt                                                                    |
| 22 | Jennifer E. Nelson    | Return on Equity (ROE)                                                                                            |
| 23 | Markus B. Leuker      | Electric Sales Forecast and Demand Response Programs                                                              |
| 24 | Jason E. Sparks       | Customer Service O&M and Energy Assistance Programs                                                               |
| 25 | Michael S. Cooper     | Benefit Expense and Post-Employment Benefits Costs                                                                |
| 26 | Matthew A. Fix        | Employee Compensation including Incentive and Retirement Income                                                   |
| 27 | Theresa M. Uzenski    | Financial Statements, Ratemaking, and Corporate Staff Group Capital Expenditures and O&M                          |
| 28 | Sherri L. Wisniewski  | Federal Income Tax, Michigan Corporate Income Tax, Municipal Income Tax, and Property Tax                         |
| 29 | Aaron Willis          | Residential Rate Design, Surcharge Design, and Other Tariff Changes, as well as Infrastructure Recovery Mechanism |
| 30 | Rodrigo Cejas Goyanes | Unbundled Cost of Service Studies and Revenue Requirement                                                         |
| 31 | Quinn Gerdes          | Forecast Allocation Schedules and Methodology                                                                     |
| 32 | Anthony Turner        | Commercial and Industrial Rate Design                                                                             |
| 33 | Kirk M. Vangilder     | Revenue Sufficiency and Net Operating Income                                                                      |

1

2

3

4

5

6

- 1) Mr. Marco A. Bruzzano, Senior Vice President, Regulatory Affairs, reviews the methodology used to develop the Company's projected revenue deficiency, provides a summary of the Company's electric rate case and the resulting customer benefits and describes the importance of timely cost recovery to support the investments needed to achieve these benefits.

Line  
No.

- 1           2) Mr. Akarsh Sheilendranath, Principal at the Brattle Group, explains how under  
2           recovery of capital expenditure for needed utility investments affect the  
3           Company's regulatory and business risks. Specifically, he discusses the effect  
4           of business, financial and regulatory risks, including regulatory lag, on the  
5           expected returns investors require to bear risks. He also explains how under  
6           recovery adversely affects the financial metrics of the Company.  
7  
8           3) Mr. William H. Ludlow, Director of the Energy and Utilities practice at West  
9           Monroe Partners, LLC, summarizes how the Company's cost forecasts in this  
10          proceeding should be interpreted, in conformance with industry standards for  
11          cost estimation.  
12  
13          4) Mr. Tim S. Lyons, Partner with ScottMadden, Inc., supports the Company's use  
14          of constant dollar averaging to develop its cost forecasts. He demonstrates that  
15          constant dollar averaging is consistent with economic principles, ensures cost  
16          forecasts adjust for inflationary trends, and is a recognized practice in  
17          developing cost forecasts.  
18  
19          5) Mr. Bill Chiu, Vice President – Distribution Engineering and Technology,  
20          discusses the Company's distribution operations and related expenditures, as  
21          well as an overview of the state of DTE Electric's distribution power grid and  
22          the planned distribution grid investments that are needed to continue to safely  
23          and reliably serve our customers, to harden the power grid against the inclement  
24          weather conditions of greater frequency and intensity and to address the

Line  
No.

1 increasing reliance on electricity while facilitating the transition to a future with  
2 more diverse distributed energy resources (DERs).

3

4 6) Mr. Allen J. Kryscynski, Director – Distribution Operations Regulatory  
5 Strategy and Grid Modernization, supports the historical O&M expenses related  
6 to electric distribution activities for 2023 historical period and projected  
7 expenses for 2024 through December 31, 2026, the Distribution Operations'  
8 Global Prioritization and Reliability Models and updates the Distribution  
9 Operations approach to Environmental Justice, and other DO related issues.

10

11 7) Mr. Joseph E. Robinson, Direction Asset Optimization, supports, as reasonable  
12 and prudent, the historical capital expenditures for 2023 and projected capital  
13 expenditures for 2024 to December 31, 2026, in the distribution strategic  
14 category of Infrastructure Resilience and Hardening. In addition, his testimony  
15 will include support for specific programs included in the Infrastructure  
16 Recovery Mechanism (IRM) proposed by Company Witness Willis.

17

18 8) Mr. Ryan M. Stowe, Vice President of Reliability Operations, supports, as  
19 reasonable and prudent, the historical capital expenditures for 2023 and  
20 projected capital expenditures for 2024 through December 31, 2026, in the  
21 distribution strategic investment category of Infrastructure Redesign and  
22 Modernization and discusses programs associated with the Company's IRM  
23 described by Company Witness Willis.

Line  
No.

- 1           9) Mr. Stephen P. Rademacher, Manager – Engineering Standards and Design  
2           supports, as reasonable and prudent, the historical capital expenditures for  
3           2023, the projected capital expenditures for 2024 through December 31, 2026  
4           in the distribution strategic investment category of the Technology and  
5           Automation Pillar, and the programs associated with the Company’s IRM  
6           discussed by Company Witness Willis.
- 7
- 8           10) Mr. Jason De Stigter, Director, Utility Investment Planning at 1898 & Co. (the  
9           advisory and technology consulting arm of Burns & McDonnell), provides  
10          analytical support for the benefit cost analysis (BCA) for four Distribution  
11          Operations investment programs included within the rate case filing. The four  
12          programs include: Pole and Pole Top Maintenance & Modernization (PTMM),  
13          Strategic Undergrounding, Distribution Automation (DA), and Grid  
14          Automation Telecommunications.
- 15
- 16          11) Mr. Brian L. Hill, Director – Southwest Regional Customer Operations and  
17          Scheduling & Coordination, supports, as reasonable and prudent, the historical  
18          capital expenditures and proposed capital expenditures related to base capital  
19          programs (emergent replacements, customer connections, relocations, and  
20          others). In addition, he provides an explanation of the Company’s purchase and  
21          use of Portable Generators and an update on MISS DIG (which is not a capital  
22          program or expenditure) reporting changes made since Case No. U-21534.

Line  
No.

1 12) Ms. Rachel C. Steudle, Director of Tree Trim, discusses the importance of and  
2 progress made in DTE Electric's vegetation management ("Tree Trimming")  
3 program, provides details related to the Company's Tree Trimming Surge  
4 Program, and describes the customer benefits of the Company's Tree Trimming  
5 Surge Program to date. She supports the O&M expenses related to tree  
6 trimming efforts for the historical test period ending December 31, 2023, and  
7 the projected O&M expenses for Tree Trim for January 1, 2026, through  
8 December 31, 2026. In addition, she discusses the future of the Tree Trim  
9 program once the Tree Trimming Surge Program is complete.

10

11

12 13) Mr. Christopher J Hartley, Business Strategy and Support Manager –  
13 Community Lighting, supports the energy forecast for outdoor lighting; the  
14 development of the proposed rate design for the outdoor lighting rate schedules  
15 (municipal lighting and other) as well as supports the reasonableness of the  
16 historic and projected Community Lighting O&M and the Community Lighting  
17 capital expenditures. He also discusses preventative maintenance programs and  
18 outage restoration activities for community lighting.

19

20 14) Ms. Margaret E. Guillaumin, Plant Director – Energy Supply Operations  
21 Performance, supports the O&M and capital expenditures for Energy Supply  
22 steam power generation, hydraulic power generation (Ludington), and other  
23 power generation for the historical test year ended December 31, 2023, the 24-  
24 month bridge period ending December 31, 2025, and the 12-month projected  
25 test period ending December 31, 2026. She provides a review of the Fossil



Line  
No.

1           Generation base coal unit availability performance for five years prior and five  
2           years following the projected test year in this instant case. She also discusses  
3           how the Environmental Protection Agency’s Steam Electric Effluent Limitation  
4           Guidelines Rule affects required coal-fired generation investment and supports  
5           the historical 2023 level of capital expenditures on a plant level basis and the  
6           forecast of capital expenditures planned for 2024 through December 31, 2026.

7

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

12

13          16) Mr. David C. Milo, Fuel Resource Specialist – Fuel Supply, supports DTE  
14          Electric Fuel Supply’s and Midwest Energy Resources Company’s (MERC)  
15          O&M and capital expenditures for the 12-month historical test period ended  
16          December 2023 and the projected O&M and capital expenditures for the interim  
17          forecast period. He also supports the Fuel Supply projected O&M and capital  
18          expenditures from 2024 through December 31, 2026. In addition, he addresses  
19          how the Company’s transition from coal generated electricity will affect MERC  
20          transshipment operations and the railcar fleet for the Company as well as the  
21          planned retirement of operations at MERC.

22

23          17) Mr. Shawn D. Burgdorf, Manager of the Power Supply Strategy & Modeling –  
24          Generation Optimization supports capacity-related costs that are part of the  
25          Company’s power supply costs, establishes the projected wholesale market

Line  
No.

1 energy sales revenue, net of fuel, and discusses future MISO rule changes  
2 associated with Load Modifying Resources.

3

4 18) Mr. Jeffery C. Davis, Expert – Nuclear Strategic Business Operations, supports  
5 the Company’s actual nuclear O&M and capital expenditures for the 12-month  
6 historical test period ended December 31, 2023. He also discusses and supports  
7 the reasonableness of the projected nuclear O&M and capital expenditures for  
8 2024 through December 31, 2026. In addition, he supports the reasonableness  
9 of the projected Nuclear Surcharge for the projected test period ending  
10 December 31, 2026.

11

12 19) Mr. Steve B. Ambrose, Vice President and Chief Information Officer,  
13 introduces DTE Electric’s key drivers and strategy for Information Technology  
14 (IT) investments to support maintaining the security, reliability and resiliency  
15 of the Company’s provision of electric service to customers. He will also  
16 describe the IT capital investment framework and planning process that drives  
17 the IT organization’s project prioritization and cost estimation processes. In  
18 addition, he will support the reasonableness of DTE Electric’s IT capital  
19 expenditures and discuss variances in projected investments from prior cases.

20

21 20) Mr. Neal T. Foley, Director – Electric Marketing, supports the O&M, capital,  
22 and regulatory asset costs related to the Company’s Electric Vehicle (EV)  
23 programming, including its Transportation Electrification Plan (TEP). He also  
24 supports the Company’s projected Merchant Fees expense and certain

Line  
No.

1 expenditures related to the 2023 full time-of-day roll out, and the Electric  
2 Regulated Marketing O&M expense.

3

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

8

9 22) Ms. Jennifer E. Nelson, Vice President at Concentric Energy Advisors  
10 (“Concentric”), presents evidence and provides the Commission with a  
11 recommendation regarding DTE Electric’s estimated cost of and reasonably  
12 required return on equity (“ROE”) and evaluates the reasonableness of its  
13 requested capital structure.

14

15 23) Mr. Markus B. Leuker, Director – Business Planning and Development – Load  
16 Management and Forecasting, provides the Company’s current electric sales,  
17 maximum demand, and system output forecast for the period 2025-2029,  
18 including the projected 12-month test period January 1, 2026 through  
19 December 31, 2026. Witness Leuker also describes how the forecast of electric  
20 sales, maximum demand and system output is developed and supports the  
21 reasonableness of the electric sales forecast used by DTE Electric in this  
22 proceeding. In addition, he will also provide an overview of Demand Response  
23 (DR) and the regulatory framework of DR.

Line  
No.

1 24) Mr. Jason E. Sparks, Director – Revenue Management and Protection, provides  
2 details of the Company’s actual Operation and Maintenance (O&M) expenses  
3 for the twelve-month period that ended December 31, 2023, and supports the  
4 Company’s projected Customer Service O&M expenses from 2024 through  
5 December 31, 2026. He also explains the details of the Company’s Energy  
6 Assistance programs and advocacy. In addition, he provides details of several  
7 energy assistance programs including DTE’s Low Income Self-sufficiency Plan  
8 (LSP), DTE’s Low-Income Assistance (LIA) credits, DTE’s Residential  
9 Income Assistance credits (RIA), DTE’s Payment Stability Plan (PSP) pilot. He  
10 also explains and supports the \$48.2 million of projected uncollectible expense.

11  
12 25) Mr. Michael S. Cooper, Head of Total Rewards, presents an overview of benefit  
13 expense for DTE Electric for the 2023 historical test period and supports the  
14 Company’s projected expenses from 2024 through December 31, 2026. He also  
15 supports the Company’s other post-employment benefits (OPEB) costs, active  
16 employee health care and other employee benefits costs.

17  
18 26) Mr. Matthew A. Fix, Director of Compensation and Retirement Income,  
19 presents an overview of employee compensation practices, including incentive  
20 compensation, and benefit expense related to retirement income for DTE  
21 Electric for the 2023 historical test period and supports the Company’s  
22 projected expenses from 2024 through December 31, 2026.

23  
24 27) Ms. Theresa M. Uzenski, Manager – Regulatory Accounting, supports DTE  
25 Electric’s financial statements for the historical test year ended December 31,

Line  
No.

1 2023, and the projected expenses from 2024 through December 31, 2026, with  
2 certain adjustments necessary for presenting the financial information in the  
3 appropriate format for ratemaking purposes. She supports the development of  
4 the projected test year adjusted electric operating income based on forecasted  
5 changes from the normalized historical electric operating income. She supports  
6 how costs recovered from other mechanisms are excluded from the financial  
7 statements in this case including Renewable Energy Program (REP), Energy  
8 Waste Reduction (EWR), Investment Recovery Mechanism (IRM) and Power  
9 Supply Cost Recovery (PSCR). She also supports the Corporate Staff Group  
10 capital and O&M expenses for the historical and forecasted periods and  
11 explains the function of this group including the method for allocating costs to  
12 DTE Electric and other DTE Energy subsidiaries through the Shared Asset  
13 charge. She also, explains various accounting treatments including the Monroe  
14 regulatory asset and amortization over 15 years. In addition, she explains a  
15 proposal to defer and amortize investment tax credits to a battery storage asset  
16 and requests regulatory asset treatment for certain debt financing costs.

17

18 28) Ms. Sherri L. Wisniewski, Director – Tax Operations, supports the DTE  
19 Electric Federal Income Tax, Michigan Corporate Income Tax, Municipal  
20 Income Tax, property tax and other general taxes for the 2023 calendar year  
21 historical period as well as 2024 through December 31, 2026.

22

23 29) Mr. Aaron Willis, Director – Regulatory Affairs, discusses and supports  
24 residential rate design, surcharge design, and other tariff changes. He also

Line  
No.

1 describes the key components of the Company's proposal in this case for the  
2 scope and duration of the IRM.

3

4 30) Mr. Rodrigo Cejas Goyanes, Consultant – Regulatory Economics, presents the  
5 Unbundled Cost of Service (UCOS) Studies for DTE Electric's projected test  
6 year ending December 31, 2026. He also supports revenue requirement  
7 calculations for: (1) customer-related costs, (2) capacity charge by customer  
8 class, and (3) IRM by voltage class.

9

10 31) Mr. Quinn Gerdes, Senior Strategist – Regulatory Affairs, supports the Forecast  
11 Allocation Schedules and methodology utilized by the Company for the 12-  
12 month period ending December 31, 2026.

13

14 32) Mr. Anthony Turner, Senior Strategist – Regulatory Affairs, supports the  
15 proposed rate design and language modifications for the Company's  
16 commercial secondary and primary rate schedules.

17

18 33) Mr. Kirk M. Vangilder, Principal Financial Analyst – Revenue Requirement,  
19 supports DTE Electric's twelve months ended December 31, 2023, historical  
20 revenue sufficiency. In addition, he is sponsoring Net Operating Income (NOI)  
21 adjustments for interest synchronization and income tax savings, as well as the  
22 revenue conversion factor. Mr. Vangilder is sponsoring DTE Electric's twelve  
23 months ending December 31, 2026, projected revenue deficiency. He also  
24 calculates the incremental revenue requirement for DTE Electric's Tree Trim

Line  
No.

1 Surge Regulatory Asset and the return on the Monroe Regulatory Asset. Lastly,  
2 he supports the incremental revenue requirements for DTE Electric's IRM.

3

4 **Corporate Memberships**

5 **Q12. How does the Company determine which corporate memberships to acquire?**

6 A12. The Company acquires and maintains corporate memberships that support its  
7 mission to provide safe, reliable, clean and affordable energy. Decisions regarding  
8 which memberships to obtain are typically made by individual business units. A  
9 list of the corporate memberships included in DTE Electric's O&M expense for the  
10 projected test year is shown on Exhibit A-27, Schedule Q1. As shown in this  
11 exhibit, each membership generally falls under the auspices of one business unit.

12

13 **Q13. Has the Company itemized the projected costs associated with corporate**  
14 **membership fees and included justifications for why these costs are necessary**  
15 **to the Company's operations to provide reliable electric service?**

16 A13. Yes. Exhibit A-27, Schedule Q1 includes the customer benefits and cost for each  
17 membership included in the Company's projected test year. The exhibit is seven  
18 pages with pages 1 - 2 displaying, in alphabetical order, the corporate memberships  
19 which are nondiscretionary. Pages 3 – 7 include, in alphabetical order, the  
20 memberships that are discretionary. The descriptions include the specific benefits  
21 these memberships offer. Additionally, non-discretionary corporate memberships,  
22 as well as discretionary corporate memberships that exceed \$100,000, are further  
23 supported by other witnesses in the case representing the primary business unit that  
24 utilizes the membership. Exhibit A-27, Schedule Q1, columns (d) and (e) provide

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1 the witness name(s) along with their associated business unit for those customer  
2 and membership benefits.

3

4 **Q14. Do the membership costs included in the Company's revenue requirement in**  
5 **this case involve lobbying activities?**

6 A14. No. Memberships, or portions of memberships, related to lobbying activities are  
7 excluded from DTE Electric's revenue requirement. Witness Uzenski supports  
8 how certain memberships, and their related costs have been excluded. As  
9 mentioned above the costs shown on Exhibit A-27, Schedule Q1 represent the costs  
10 that are proposed for inclusion in rates, exclusive of lobbying-related costs. The  
11 amounts shown on Exhibit A-27, Schedule Q1 have not been adjusted for inflation  
12 although are included in the Company's revenue requirement with an inflation  
13 adjustment.

14

15 **Q15. In the Company's most recent rate case, Case No. U-21534, what did the**  
16 **Commission recommend specific to corporate memberships?**

17 A15. The Commission, on page 466, directed the company to provide a discussion of  
18 actual processes, projects, procedures, or other tangible impacts benefiting the  
19 Company's customers that have resulted from nondiscretionary corporate  
20 memberships.

21

22 **Q16. Did the Company provide this information?**

23 A16. Yes, Exhibit A-27, Schedule Q1, columns (d) and (e) provides the witness' name  
24 along with their associated business unit for a discussion of the benefits related to



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1 the nondiscretionary corporate memberships. Refer to Witnesses Davis and  
2 Kryscynski direct testimonies for additional discussion.

3

4 **Q17. What benefits are realized from DTE Electric's memberships in the**  
5 **organizations listed on Exhibit A-27, Schedule Q1?**

6 A17. In addition to the benefits included in each membership's description and  
7 supporting witnesses' testimony (reference column (d) of Exhibit A-27, Schedule  
8 Q1, pages 3-7), the benefits the Company and its customers receive from the  
9 memberships listed in Exhibit A-27, Schedule Q1, pages 3 through 7 generally fit  
10 into one or more of the following broad categories:

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

22

23 **Q18. Are you providing additional support for any of the corporate memberships**  
24 **requested for recovery?**

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1 A18. Yes. As noted above, Exhibit A-27, Schedule Q1 lists the supporting witness' for  
2 discretionary memberships over \$100,000. The one membership that I am  
3 supporting is the Edison Electric Institute (EEI).

4

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

- 11 • Mutual assistance coordination across the nation that enables DTE Electric  
12 to quickly secure resources for storm restoration. The industry has no other  
13 mutual assistance structure;
- 14 • Information on technology industry security initiatives and best practices;
- 15 • Assistance identifying and networking with diverse suppliers specific to the  
16 utility industry as well as sharing best practices regarding supplier diversity;
- 17 • Benchmarking on utility-driven economic development;
- 18 • Benchmarking around solar and battery storage commissioning strategies  
19 and best practices;
- 20 • Benchmarking around uncollectible expenses and a better understanding  
21 state policies that drive external and internal programs to assist customers;
- 22 • Surveys to understand tariff impacts on key supply chain materials;
- 23 • Sharing of best practice from transportation electrification programs around  
24 the nation; and

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- 1                   • Learning from industry experts and leaders on important topical subjects  
2                   such as battery operations and risk mitigation as well as decarbonization.

3

4    **Voluntary Separation Incentive Program**

5    **Q19. Can you describe the Company's Voluntary Separation Incentive Program**  
6           **(VSIP)?**

7    A19. A Voluntary Separation Incentive Program (VSIP) was offered to 1,025 DTE  
8       Electric employees and 1,622 DTE Energy Corporate Services, LLC employees  
9       (shared service employees) on January 8, 2024. Employees were considered  
10      eligible if they did not fall under certain criteria, including, but not limited to:  
11      represented (union) employees, engineers, operations critical employees (e.g.,  
12      control room operators, cybersecurity roles). The VSIP included 25 weeks of an  
13      employee's base salary plus one additional week for every year of service up to a  
14      maximum of 44 weeks total. The effective separation date varied from February  
15      2024 through June 2024.

16

17   **Q20. What was the primary purpose of the VSIP?**

18    A20. A primary purpose of the VSIP was to realign the workforce to support the  
19       changing nature of the Company's work and how it is performed, such as an  
20       increased focus on infrastructure investments, cybersecurity, and the clean energy  
21       transition.

22

23   **Q21. In the Company's most recent rate case, Case No. U-21534, what did the**  
24       **Commission determine regarding VSIP?**

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1 A21. The Commission decreased DTE Electric's projected 2025 Operations and  
2 Maintenance (O&M) expenses by \$10.1 million. This amount was included in the  
3 total adjusted net operating income.

4

5 **Q22. Did the Company include VSIP savings in the projected test year?**

6 A22. Yes.

7

8 **Q23. What is the Company's total projected net 2026 O&M net savings related to**  
9 **VSIP?**

10 A23. DTE Electric estimates the projected 2026 O&M net savings, as shown in Exhibit  
11 A-30, Schedule T1, is \$22.6 million. This amount represents the net savings  
12 (departures of approximately 400 employees net of new hires of approximately 200  
13 employees), inclusive of labor, operating and financial incentives, employee  
14 benefits (net of Pension and OPEB) and payroll tax and exclusive of program costs.  
15 This adjustment to O&M is reflected on the individual Company witness exhibits.

16

17 **Outage Credit Cost Recovery**

18 **Q24. In the Company's most recent rate case, Case No. U-21534, what did the**  
19 **Commission recommend specific to outage credit cost recovery?**

20 A24. At page 362 of the referenced Order in Case No. U-21534, the Commission agreed  
21 with Staff that: "1) [f]or credits paid for outages that exceed the duration limit, only  
22 those outages caused by a transmission operator or another utility should be  
23 recovered from ratepayers, and 2) for credits paid to customers for exceedance of  
24 the outage frequency limit, the recoverable portion of the total credit amount

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1 provided to ratepayers should correspond only to outages caused by the  
2 transmission operator, another utility, or public interference.”

3

4 **Q25. Did the Commission recommend anything else specific to outage credit cost**  
5 **recovery?**

6 A25. Yes. At page 363 of the referenced Order in Case No. U-21534 the Commission  
7 directed “DTE Electric to collaborate with the Staff to develop a procedure for  
8 limited recovery of outage credits, as described above, and directs the company to  
9 defer the costs for review and recovery in a future rate case using account 182.3,  
10 Other Regulatory Assets.”

11

12 **Q26. How did the Company respond to that directive?**

13 A26. The Company met with Staff in the first half of 2025 to review and refine a process  
14 for deferring the cost of outage credits that are eligible for cost recovery. Under  
15 the Company’s cost recovery proposal, the deferred costs would be reviewed in a  
16 subsequent rate case, and if approved by the Commission, the costs would be  
17 included in rates. The Company anticipates that the expense approved for recovery  
18 in rates would be amortized over a three-year period. Refer to Witness Uzenski for  
19 details regarding the regulatory asset.

20

21 The data reviewed by the Company and Staff indicated that in the years 2022  
22 through 2024 there were fewer than 110 customer outages in total that would have  
23 qualified for cost deferral. Due to the relatively small amount of expense involved,  
24 the Company does not plan on pursuing cost recovery for these customer outage

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1 credits unless the expense becomes material. The Company has not determined a  
2 materiality threshold for these costs at this time.

3

4 **Q27. Has the Company included any expense in its revenue requirement to recover**  
5 **the cost of customer outage credits in this rate case, Case No. U-21860?**

6 A27. No, DTE Electric has not included any expense in this rate case for customer  
7 outage credits.

8

9 **Q28. Does this complete your direct testimony?**

10 A28. 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-21860

QUALIFICATIONS  
  
AND  
  
DIRECT TESTIMONY  
  
OF  
  
AKARSH SHEILENDRANATH

**DTE ELECTRIC COMPANY**  
**QUALIFICATIONS AND DIRECT TESTIMONY OF AKARSH**  
**SHEILENDRANATH**

Line  
No.

1 **Introduction**

2 **Q1. Please state your name, current title, and address for the record.**

3 A1. My name is Akarsh Sheilendranath. I am employed as Principal at the Brattle Group.  
4 My business address is The Brattle Group, 555 Mission Street, Suite 1500, San  
5 Francisco, CA 94105, USA.

6

7 **Q2. On who's behalf are you testifying?**

8 A2. I am submitting this testimony on behalf of DTE Electric Company ("DTE Electric" or  
9 the "Company") before the Michigan Public Service Commission (the "Commission").

10

11 **Q3. What is your educational background?**

12 A3. I received an MBA in Finance from New York University Stern School of Business,  
13 an M.S. in Electrical Engineering with a specialization in Power Systems Engineering  
14 from Michigan Technological University, and a B.E. in Instrumentation Technology  
15 from Siddaganga Institute of Technology in India.

16

17 **Q4. Please describe your professional background.**

18 A4. I am an energy economist with a background in power engineering and finance. I have  
19 over fifteen years of experience in the areas of cost of capital, wholesale electricity  
20 markets, economic evaluation of generation and transmission investments, investment  
21 risk, and related matters for many industries, regulated and unregulated alike. I have  
22 assisted numerous clients, including regulated utilities, ISOs/RTOs, public utility  
23 commissions, and private entities, and have testified and authored publications and



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1 reports on subject areas related to the cost of capital, including return on equity  
2 estimation, the economic benefits of transmission and generation investments,  
3 renewable generation integration, transmission congestion risks, transmission and  
4 resource planning, and a wide range of issues relating to wholesale energy and capacity  
5 markets. I have provided pre-filed and oral testimony in matters related to the  
6 estimation of cost of capital and return on equity, the economics of generation  
7 investment, utility resource planning, resource adequacy and reliability, transmission  
8 grid congestion risks, and transmission market rule changes in ISO/RTO markets for  
9 state and federal jurisdictional regulated utilities. Most recently, prior to rejoining the  
10 Brattle Group, I was the director of the integrated resource planning and strategy group  
11 of American Electric Power (“AEP”) Service Corporation, where I oversaw the  
12 planning and investment of regulated generation to support AEP operating companies,  
13 resource adequacy and capacity positions of AEP companies, and generation  
14 innovation opportunities. I similarly advised AEP transmission and policy groups and  
15 testified in company rate cases and integrated resource plan proceedings.

16

17 **Q5. Have you previously sponsored testimony before the MPSC?**

18 A5. No, I have not previously sponsored testimony before the MPSC. However, I have  
19 sponsored pre-filed and oral testimony before several U.S. regulatory agencies,  
20 including before the U.S. Federal Energy Regulatory Commission, as well as in the  
21 states of Arkansas, California, Louisiana, New Jersey, Oklahoma, Texas, and Virginia.  
22 A summary of my professional experience and education is included in Exhibit A-35  
23 Schedule Z1.

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1 **Q6. What is the purpose of your testimony in this proceeding?**

2 A6. The purpose of my testimony is to explain how under recovery of capital expenditures  
3 for needed utility investments affect the Company's regulatory and business risks, and  
4 the various implications of higher risks for the Company. Specifically, I discuss the  
5 effect of business, financial, and regulatory risks, including the regulatory lag and  
6 asymmetry risks that disallowances induce, on the expected returns investors require  
7 to bear such risks. I explain how under recovery adversely affect the financial metrics  
8 of the Company and describe the long-term implications to credit ratings and the  
9 Company's capital outlays. I illustrate the adverse effect that capital expenditure  
10 disallowances would have on the cost of capital and investors' expected rate of return.

11

12 **Q7. Are you sponsoring any exhibits?**

13 A7. Yes, I am sponsoring the following exhibit:

| <u>Exhibit</u> | <u>Schedule</u> | <u>Description</u>                                                |
|----------------|-----------------|-------------------------------------------------------------------|
| A-35           | Z1              | Professional Experience and Education of Akarsh<br>Sheilendranath |

17

18 **Q8. Was this exhibit prepared by you or under your direction?**

19 A8. Yes, it was.

20

21 **Q9. How is the remainder of your testimony organized?**

22 A9. First, I provide the background of the Company's investment needs. Next, I discuss in  
23 detail the various impacts of regulatory risk, including implications of under recovery  
24 risks on credit ratings and investors' expected returns to bear such risk, and the long-

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1 term implications to the Company and its customers. Then I explain the concepts of  
2 cost of capital, rate regulation and illustrates how cost recovery risk affects investors  
3 expected returns. Last, I summarize my testimony.

4

5 **Background**

6 **Q10. Please provide your understanding of DTE Electric's investment needs.**

7 A10. DTE Electric plans to invest heavily in Michigan's energy infrastructure to improve  
8 grid reliability and aid the clean energy transition<sup>1</sup>. DTE Electric's investments will  
9 focus on rebuilding and reinforcing the aging electric distribution grid and investing in  
10 its power generation fleet, including investments in beneficial<sup>2</sup> utility-scale energy  
11 storage to serve a growing demand for power and maintaining resource adequacy.  
12 These efforts are primarily required to address generation and grid reliability needs, to  
13 support the transition to cleaner generation sources economically, to aid with  
14 transportation electrification, and to improve service quality for customers, consistent  
15 with the service quality and reliability standards set forth by the Michigan Public  
16 Service Commission (MPSC)<sup>3</sup>. Furthermore, these needed investments are expected to  
17 provide substantial economic benefits, such as job growth, tax revenues, and related  
18 economic impacts to communities the Company serves<sup>4</sup>.

---

<sup>1</sup> Reuters, "DTE Energy raises capex plan, fourth-quarter profit falls on lower rates", February 13, 2025, <https://www.reuters.com/business/energy/dte-energy-posts-fall-fourth-quarter-profit-lower-rates-2025-02-13/>.

<sup>2</sup> DTE Energy Business Update, January 8, 2025, p. 6, [https://s24.q4cdn.com/970999156/files/doc\\_presentations/2025/01/Evercore-ISI-presentation-final.pdf](https://s24.q4cdn.com/970999156/files/doc_presentations/2025/01/Evercore-ISI-presentation-final.pdf).

<sup>3</sup> Fitch Ratings, "Fitch Affirms DTE Energy, DTE Electric Co. and DTE Gas Co.'s Ratings; Outlook Stable", March 21, 2024, p. 3.

<sup>4</sup> See Direct Testimony of Company Witness Marco A. Bruzzano, pp. 11-12.

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1 **Impact of Regulatory Risk**

2 **Implications of Capital Under Recovery on Risk**

3 **Q11. Can you explain the implications of potential future capital disallowances?**

4 A11. Yes. The key implication to DTE Electric is that potential future disallowances exposes  
5 investors, who fund the capital the Company deploys, to a higher degree of regulatory  
6 risk and an expected return both below the authorized return, and below the level of  
7 return required by investors. Higher regulatory risk will make the Company more risky  
8 from investors' perspective, necessitating a higher required rate of return to attract  
9 investor capital.

10

11 When these risks materialize, for example, in the form of regulatory lag resulting from  
12 a disallowance, the Company may have no mitigating levers in the short-term to  
13 address the adverse financial effects, precisely because much or the entirety of near-  
14 term investments may be needed and may not be retimed without adverse impacts on  
15 reliability and service quality. This leads to the Company absorbing those costs, which  
16 reduces the opportunity to earn both its authorized return and investor's required return.

17

18 Persistent disallowances increase the Company's regulatory risk, i.e., the uncertainty  
19 associated with future recovery will increase. When faced with higher regulatory risk,  
20 investors' *ex ante* expected rate of return to fund the utility's future capital investments  
21 will increase. In other words, the Company's cost of capital will increase, and if not  
22 adequately addressed through higher authorized rates of return to match the higher cost  
23 of capital that investors now require, the utility will not have a fair opportunity to earn  
24 its cost of capital. Stock prices would decline and the Company's credit metrics will  
25 worsen, adversely affecting the Company's credit quality and the overall financial

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1 health. Eventually, the Company will be forced to scale back its long-term investment  
2 plans, which would affect reliability and customer costs.

3 As an investor-owned utility (IOU), the Company has the responsibility to  
4 maintain its financial integrity to be able to attract investor capital at lowest required  
5 rates of return, commensurate with the Company's systematic risks (i.e., non-  
6 diversifiable financial, business, and regulatory risks). Investor funded capital is  
7 deployed to finance the investments required to provide reliable electric service to its  
8 customers cost-effectively. In return, investors expect that the Company's investments  
9 would generate the required rate of return for their capital. It is the Company's  
10 responsibility to deliver on this expectation, which is possible when the allowed return  
11 is set at the market-determined cost of capital, commensurate with the Company's  
12 business, financial, and regulatory risks. This ensures that customers benefit through  
13 required capital investments that provide stable and quality electric service, at lower  
14 rates.

15 If a regulatory policy or a practice that increases the recovery risk were to  
16 materialize, investors would be exposed to additional regulatory risk. The higher  
17 regulatory risk would commensurately require ex ante higher rates of return for future  
18 investment capital. In the long-term, greater regulatory risk would result in higher cost  
19 of service, and can lead to undercapitalization and fewer investments, as well as lower  
20 service quality for customers.

21

22 **Q12. Please explain further how higher regulatory risk affects the Company?**

23 A12. Higher regulatory risk will make the Company more risky from investors' perspective,  
24 and a higher allowed rate of return (that matches the higher expected return) would be  
25 necessary to compensate investors for bearing a higher regulatory risk, as I discuss in

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- 1 greater detail in Section III.D.<sup>5</sup> Higher regulatory risk has the following adverse  
2 effects:
- 3 a. It will put downward pressure on the Company's credit metrics and thereby, its  
4 credit quality. If the Company's credit metrics worsen substantially as a result,  
5 credit ratings agencies could downgrade DTE Electric's unsecured debt rating,  
6 which will increase the yield demanded by debt investors to fund the Company's  
7 debt financed capital. In other words, it would increase the Company's cost of debt.
- 8 b. A materially higher cost of debt means that a larger proportion of the cash flows  
9 generated by the Company's assets will be required to service fixed debt payments,  
10 which increases the riskiness (i.e., the variability) of expected free cash flows, and  
11 thus increases the rate of return (ROE) that equity investors will demand to  
12 compensate for the higher risk they bear. The overall effect is an increase in the  
13 required ROE or the allowed equity ratio, both of which increase the Company's  
14 cost of capital.
- 15 c. If the allowed ROE (or the equity ratios) were not subsequently adjusted to reflect  
16 the higher risk borne by investors, the Company would forgo the opportunity to  
17 earn its cost of capital and would not be able to meet the rates of return demanded  
18 by its investors. Capital attraction in the long-run would be challenged (for  
19 example, via more onerous covenant agreements) or become increasingly  
20 expensive (through higher interest rate offerings or issuance of stock at a discount),  
21 and in the long-run would lead to undercapitalization, adversely impacting service

---

<sup>5</sup> Note that the higher regulatory risk would persist even if regulators approved full cost recovery of needed capital investments in one regulated business line of the fully diversified company (e.g., electric distribution business) but look to offset some of those investment cost recovery by disallowing recovery of other needed capital expenditures in another business line of the fully regulated company (e.g., generation business or IT infrastructure capital necessary to support regulated business services).

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1 quality. In the long-run, inadequate returns are likely to cost customers and the  
2 society, in general.

3

4 Without compensable return for higher risk, the fiduciary responsibility of the  
5 Company to its investors would force it to reduce capital outlays, prioritizing  
6 investments and expenditures judged to have low disallowance probabilities. Such  
7 investments may not be the most cost-effective options to address long-term needs of  
8 the system and may not yield the most value to customers. Investments prioritized to  
9 minimize cost recovery risks also impose additional costs on customers. In the long  
10 run, such investments may not be durable (i.e., they will need to be reinforced or  
11 replaced more frequently) and may also preclude the options for the Company to more  
12 cost-effectively plan and execute future system expansions or provide other planning  
13 synergies that serve to reduce customer costs in the long-term. Collectively, these  
14 effects would serve to increase customer costs and adversely impact the quality of  
15 service for customers due to reduced investments.

16

17 Summary of DTE Electric's Credit Rating and Impact of Regulatory Risk

18 **Q13. Please summarize the Company's credit ratings.**

19 A13. DTE electric has an A- credit rating from S&P, Aa3 from Moody's, and an A+ from  
20 Fitch. Credit metrics can be negatively impacted due to expected reduction in the future  
21 cash flows. Rating agencies closely monitor cash flow metrics in determining utility  
22 bond ratings. Reductions in the cash flow metrics, such as cash flow to debt ratios (i.e.,  
23 FFO to debt ratio) could negatively impact the credit profile of the Company<sup>6</sup>. If future

---

<sup>6</sup> S&P Global Ratings, "DTE Electric Co. Rate Case Outcome Modestly Below Base-Case Expectation", January 31, 2025, p. 2.

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1 cash flows carry greater risk, the Company's FFO to debt metric decreases, potentially  
2 risking credit rating downgrade. Increasing allowed ROE or adjusting the capital  
3 structure to comprise of more equity would become necessary to offset adverse impact  
4 to the Company's credit quality.

5

6 **Q14. Can regulatory risk adversely impact the Company's credit metrics?**

7 A14. Yes, if the Company's capital expenditures continue to face a higher cost recovery risk,  
8 the Company's credit metrics will worsen. In its January 31, 2025 analysis<sup>7</sup>, S&P  
9 Global Ratings noted that the Commission's determination to maintain the Company's  
10 authorized ROE at 9.9% instead of approving the requested 10.5%, "modestly weakens  
11 DTEE's funds from operations (FFO) to debt by about 30 basis points beginning in  
12 2025". It also noted the Company's forecasted FFO to debt would remain within its  
13 financial risk profile category, if the Company were able to maintain capital spending  
14 at about \$3.8 billion over the next two years, with steady cost recovery for the  
15 Company's investments.

16

17 Furthermore, a January 2025 S&P research report mentions that with the possibility of  
18 tariffs between the U.S. and countries it trades with, DTE Electric could see significant  
19 business risks as the cost of importing goods are expected rise.<sup>8</sup>

20

21 S&P currently has a stable outlook for the Company, and noted that this outlook reflects  
22 among others, the assumption that the Company will generate sufficient cash flows to  
23 maintain financial measures that support S&P Global Ratings-adjusted FFO to debt of

---

<sup>7</sup> *Id.*, p. 1.

<sup>8</sup> S&P Global Ratings, "What Looming Tariffs Could Mean for U.S. Corporates", p. 13, February 27, 2025.



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1 19%-20%. In its Downside Scenario, it cautioned that the S&P Global rating could  
2 lower the Company's credit rating within the next 24 months if its FFO to debt weakens  
3 to remain consistently below 15%. An additional factor that impacts the credit rating is  
4 Company's exposure to environmental risks, including the dependence on coal  
5 generation and exposure to nuclear generation risks. DTE Electric's generation fleet  
6 has a significant carbon footprint relative to other sector peers.<sup>9</sup> The Company will  
7 need to continue to deploy capital to replace retiring coal plants with new clean energy  
8 facilities as it plans to address the energy-transition risk.

9

10 If the Company's capital expenditures continue to face a higher cost recovery risk, its  
11 future cash flows will become more variable and less certain (i.e., riskier). The  
12 Company's currently healthy cash flow metrics would worsen, which could impact the  
13 credit profile of the Company, potentially risking a credit rating downgrade.

14

15 **Q15. If the Company's debt is rated as investment grade, and its cash flow metrics are**  
16 **currently healthy, please explain further how regulatory risk affects the**  
17 **Company's risks.**

18 A15. Regulatory risk affects not only the Company's credit ratings but also the required  
19 return expected by equity investors. The Company's investment grade credit ratings  
20 and its current cash flow metrics indicate that the Company is financially stable.  
21 However, credit ratings are not a measure of the risk of a company's equity, i.e., they  
22 do not assess the systematic and non-diversifiable risk of the Company's equity.

---

<sup>9</sup> Value Line Company Reports, accessed April 3, 2025. Reports for electric utilities are released in three groups – East, Central and West. The most recent reports for electric utilities span from January to March 2025.

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1 Instead, their current ratings only imply that rating agencies assign a low probability  
2 that the Company would default on its debt, given its current cash flow metrics.

3

4 Irrespective of the Company's investment grade credit rating, equity investors will  
5 expect a return commensurate with DTE Electric's systematic and non-diversifiable  
6 risk. As I discuss later in this testimony, regulatory risk is a non-diversifiable risk.  
7 Additional regulatory risk from persistent under recovery of invested capital will  
8 increase the required rate of return expected by equity investors even if credit ratings  
9 remain at investment grade. Of course, if the Company's capital recovery were to  
10 become more risky, the Company's currently healthy cash flow metrics would also  
11 worsen, which would increase the Company's default risk and result in a credit rating  
12 downgrade eventually. The overall effect is an increase in the Company's overall cost  
13 of capital.

14

15 **Q16. How does regulatory risk affect the Company's risk profile considering DTE**  
16 **Electric's large capital program?**

17 A16. Regulatory risk could disproportionately impact DTE Electric's earnings as the  
18 Company is projected to significantly increase its capital investments in necessary  
19 clean energy generation and the electric distribution grid. Capital expenditures  
20 introduce higher fixed costs, which, in capital-intensive industries, decay over a long  
21 time, and thus cannot be eliminated if circumstances change in the future. This  
22 increases the Company's business risk. Any risk associated with timely and/or full cost  
23 recovery will become more relevant, considering the Company's large, planned capital  
24 program over the next several years. The Company already incurs a substantial amount  
25 of fixed costs to operate a network of capital-intensive assets to generate and deliver

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1 electricity to customers. Therefore, it must earn sufficient revenues—which are  
2 variable—each period to cover those fixed costs. As the Company increases its capital  
3 investment, a greater proportion of its expenses will be fixed, increasing its business  
4 risk profile (relative to peers).

5

6 The effect is that the Company’s cash flows will become more risky because any  
7 reduction in revenue will have a disproportionately large effect on profits. As DTE  
8 Electric projects large increases in grid and clean energy investments over the next 5  
9 years, any additional regulatory risk, such as from disallowances on cost recovery of  
10 prudently incurred investments would further exacerbate the Company’s risk profile  
11 relative to its peers, further necessitating higher allowed return to attract capital.

12

### 13 Expected Returns and Cost of Capital in Rate Regulation

#### 14 **Q17. What is Cost of Capital?**

15 A17. The cost of capital is defined as the expected rate of return<sup>10</sup> in capital markets on  
16 alternative investments of equivalent risk.<sup>11</sup> In other words, it is the rate of return  
17 investors require on an investment based on the risk-return alternatives available in  
18 competitive capital markets. The cost of capital is a type of opportunity cost—it  
19 represents the rate of return that investors could expect to earn elsewhere without  
20 bearing more risk.

---

<sup>10</sup> The term “expected” in the expected rate of return is used in the statistical sense. It is the mean of the distribution of possible outcomes. It represents the probability-weighted average over all possible outcomes.

<sup>11</sup> See Brealey, Myers, and Allen, *Principles of Corporate Finance*, 12<sup>th</sup> edition, 2017, McGraw-Hill/Irwin, p.10 for a discussion of the opportunity cost of capital.

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1 **Q18. Please explain why the cost of capital is relevant in rate regulation.**

2 A18. It is common practice in U.S. rate regulation to employ the cost of capital as the  
3 appropriate expected rate of return on utility investment.<sup>12</sup> This practice is deemed  
4 consistent with the U.S. Supreme Court's opinions in *Bluefield Waterworks &*  
5 *Improvement Co v. Pub. Serv. Comm'n of West Virginia*, 262 U.S. 679 (1923), and  
6 *FPC v. Hope Nat. Gas Co.*, 320 U.S. 591 (1944).

7

8 From an economic perspective, competition for investable capital determines the  
9 minimum required rate of return that must be offered to investors. Regulated rates  
10 should be set such that investors have the fair opportunity to earn this minimum  
11 expected rate of return, i.e., the cost of capital, that compensate for the risks they bear.  
12 Over the long run, an expected return below the cost of capital under compensates  
13 investors, denying the Company the ability to attract capital, to maintain its financial  
14 integrity, and to expect a return commensurate with that of other enterprises with  
15 similar risks. To the contrary, when the expected return is consistently above the cost  
16 of capital, customers overpay for service, unless there are certain offsetting benefits,  
17 such as through incentive regulation or differing rates for renewables, as in the case of  
18 DTE Electric. In general, however, regulatory commissions serve to prevent investors  
19 earning expected rates of return in excess of the cost of capital in the long-run. Sound  
20 regulatory practices aim to set rates at levels such that investors expect to earn the cost  
21 of capital on average, which in the long-run appropriately balances the interests of both  
22 customers and investors.

---

<sup>12</sup> The field of financial economics has established the link between the cost of capital and the appropriate expected rate of return for utilities. See *Application of Finance Theory to Public Utility Rate Cases*, Stewart Meyers, *Bell Journal of Economics & Management Science* 3:58-97 (1972).

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1 Effect of Risks on Expected Returns

2 **Q19. What risks are relevant to investors' expected return and the cost of capital?**

3 A19. It is the systematic risk, i.e., the non-diversifiable risk, that informs the expected return  
4 and the cost of capital associated with an investment. In utility rate regulation,  
5 systematic risk is also referred to as business risk, project risk, or asset risk; and in  
6 regulated industries, it is affected by regulatory risk, i.e., the regulatory policies  
7 governing rate regulation and cost recovery.

8

9 While the overall cost of capital depends on the business risk of the company, the costs  
10 of the debt and equity components of the cost of capital depend not only on the business  
11 risk, but also on the distribution of revenue between debt and equity. This is referred to  
12 as the financial risk and is an important consideration along with the business risk in  
13 estimating the cost of equity (i.e., the appropriate ROE) of a company based on a  
14 sample of other enterprises of corresponding risk. The cost of equity and the capital  
15 structure are entwined in that the use of debt increases the financial risk of the company  
16 and therefore increases the cost of equity. The more debt, the higher is the cost of equity  
17 for a given level of business risk. Although, the overall cost of capital, which  
18 corresponds to systematic risk, remains constant (ignoring taxes and costs of excessive  
19 debt).

20

21 **Q20. What is business risk?**

22 A20. Business risk refers to the risk associated with the free cash flows that an enterprise's  
23 assets or projects would generate in the future. Specifically, it is the risk that the  
24 enterprise's assets or projects will fail to successfully generate the expected free cash

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1 flows over its operable life. This includes the risk that a project may fail to even be  
2 placed into service and therefore must be abandoned, and the risk of early termination  
3 of projects placed into operations.

4

5 **Q21. What is regulatory risk?**

6 A21. Regulatory risk is entwined with business risk. It informs the regulatory environment  
7 that a business enterprise operates within to generate the enterprise's future free cash  
8 flows. Regulatory risk is a non-diversifiable risk and aspects of it may be asymmetric.  
9 Regulatory risk is very important to a utility, and a stable and supportive regulatory  
10 environment reduces a utility's cost of capital and enhances its credit rating. Because  
11 regulatory risk is part of the overall business risk, it affects the investors' expected rate  
12 of return.

13

14 **Q22. What is asymmetric risk?**

15 A22. An asymmetric risk is a downside loss risk without an equivalent upside chance for  
16 gains. In rate regulation, rates are set such that the allowed rate of return on regulated  
17 investments is equal to the utility's cost of capital. This means that the utility has a fair  
18 opportunity, on average, to earn its cost of capital when the upside and downside risks  
19 are balanced. However, when faced with asymmetric risk, investors do not have the  
20 fair opportunity to earn the cost of capital because their expected return, considering  
21 both upside and downside risks, do not balance. In other words, when the allowed rate  
22 of return is set at the utility's cost of capital, investors are not compensated for  
23 asymmetric risks. This may benefit customers through lower rates but, it forecloses  
24 compensation to investors for bearing asymmetric risk.

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1 In DTE Electric's case, regulatory lag as a result of cost recovery disallowance on  
2 already incurred expenditures may be an asymmetric risk. That is, when regulatory lag  
3 arises, the Company's investors earn below the allowed rate of return, and when that  
4 regulatory lag is removed, investors earn the allowed rate of return (not more to balance  
5 the loss when lag arises). That means, the expected rate of return investors earn—which  
6 is the weighted average of rate of return across both scenarios, wherein investors (1)  
7 expect to earn the allowed return when there is no regulatory lag, and (2) expect to earn  
8 less than the allowed return in years with regulatory lag—is less than the allowed rate  
9 of return set by the Commission. This means that DTE Electric's allowed rate of return,  
10 set at its market-determined cost of capital, does not compensate investors for bearing  
11 regulatory lag risk.

12

13 **Q23. How do these risks affect the expected return from an investment?**

14 A23. Investors' willingness to invest in cash flow generating assets or enterprises depends  
15 on the expected cash flows from that investment. The cash flows must be sufficient to  
16 (1) recover the invested capital and (2) earn a rate of return at least equal to the cost of  
17 capital associated with that investment (before considering asymmetric risk). The  
18 higher the business and regulatory risks, the higher would be the required cash flows,  
19 and therefore, higher the required rate of return (or other compensation), to bear those  
20 risks.

21

22 **Q24. Does cost recovery disallowance on utility investments affect regulatory risk?**

23 A24. Yes, it does. If there is risk that regulatory measures may disallow cost recovery  
24 associated with needed capital projects, investors will bear higher regulatory risk, and

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1 therefore will require higher cash flows from the project to compensate for the under  
2 recovery risk. The more persistent the under recovery, higher the risk investors will  
3 assign to the utility.

4

5 **Q25. Please explain further how regulatory risk affects investors' expected cash flows.**

6 A25. Consider the following illustrative example that demonstrates how regulatory risk  
7 affects investors' expected cash flows and rate of return.

8

9 Consider two identical projects, Project A and Project B, each requiring \$100 million  
10 of investment. Assume that both projects have no project failure risk or early  
11 termination risk, i.e., there is certainty that both projects will be developed and operated  
12 to provide useful service through their respective economic lives. For simplicity, also  
13 assume that asymmetric risks have been removed for both projects.

14

15 Now consider that there is a 10 percent probability that 100 percent of Project B's costs  
16 would be disallowed from recovery through regulated rates, while Project A has no  
17 such cost recovery risk.

18

19 I will evaluate Project A first. Because it carries neither project failure / early  
20 termination risk nor cost recovery risk, Project A would be expected to earn no more  
21 than its cost of capital. Thus, if the allowed rate of return for this project were set equal  
22 to the project's cost of capital, it would adequately compensate investors' expected rate  
23 of return, which is the cost of capital.



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1 Now consider Project B. Recall that Project B bears a 10 percent risk that the entirety  
2 of its invested capital (i.e., \$100 million) may be disallowed from regulated recovery.  
3 This means that investors expect *ex ante* cash flows from the project to be sufficiently  
4 high to compensate for the 10 percent probability that they may not recover any of the  
5 invested \$100 million capital. To compensate for this 10 percent chance of zero  
6 recovery, they will demand a higher rate of return. Figure 1 illustrates this  
7 mathematically.

8

9 As shown in Figure 1, there are two possible outcomes for investors to consider: a  
10 scenario where the 10 percent risk of \$100 million disallowance manifests and the  
11 scenario in which such a risk does not. Across both possible scenarios—which  
12 represents the distribution of all possible outcomes in this example—investors will  
13 need to recover their total investment of \$100 million for the project, and a rate of return  
14 commensurate with the risk of expected cash flows associated with the project.

15

16 What this means is that to offset the effect of the 10 percent probability that 100 percent  
17 of the investment may be disallowed, the cash flows associated with the 90 percent  
18 chance scenario (one wherein no disallowance happens) would need to be higher. This  
19 way, the expected cash flows—i.e., the probability-weighted average cash flows across  
20 *both* possible outcomes—is still equal to the total investment amount of \$100 million  
21 plus the required rate of return. Mathematically, this translates to required cash flows  
22 equal to \$111.1 million for the 90 percent chance scenario.

23

24 Thus, the allowed rate of return for Project B will need to be set higher such that when  
25 the expected project cash flows are discounted at that higher rate of return, the net

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1 present value will equal the original investment of \$100 million. As shown in Figure  
2 1, Project B will require a higher allowed rate of return (8.90 percent) as a result of the  
3 10 percent chance that its investors will recover none of the investment, compared to  
4 Project A's lower cost of capital (7.25 percent) because Project A bears no such risk.  
5 At their respective cost of capital rates, both projects will have the fair opportunity  
6 (commensurate with the respective risks) to recover their investments.

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1

**Figure 1 : Impact of Disallowance Risk on Expected Rate of Return**

|                                             |            | Probability<br>[1] | NPV (\$M)<br>[2] | Probability-Weighted<br>Cash Flow (\$M)<br>[3] |
|---------------------------------------------|------------|--------------------|------------------|------------------------------------------------|
| <b>Project A</b>                            |            |                    |                  |                                                |
| <b>Scenario 1 : Additional Disallowance</b> |            |                    |                  |                                                |
| Risk Manifests                              | [G]        | 0%                 | NA               | NA                                             |
| <b>Scenario 2 : Normal Cost Recovery</b>    |            |                    |                  |                                                |
| (no disallowance risk)                      | [H]        | 100%               | 100.00           | 100.00                                         |
| <b>Expected Cash Flow</b>                   | <b>[I]</b> |                    |                  | <b>100.00</b>                                  |
| <b>Cost of Capital</b>                      | <b>[J]</b> |                    |                  | <b>7.25%</b>                                   |
| <b>Project B</b>                            |            |                    |                  |                                                |
| <b>Scenario 1 : Additional Disallowance</b> |            |                    |                  |                                                |
| Risk Manifests                              | [K]        | 10%                | 0.0              | 0.0                                            |
| <b>Scenario 2 : Normal Cost Recovery</b>    |            |                    |                  |                                                |
| (no disallowance risk)                      | [L]        | 90%                | 111.11           | 100.00                                         |
| <b>Expected Cash Flow</b>                   | <b>[M]</b> |                    |                  | <b>100.00</b>                                  |
| <b>Allowed Rate of Return</b>               | <b>[N]</b> |                    |                  | <b>8.90%</b>                                   |

Sources and Notes:

[G][3]: [G][1]\*[G][2].

[H][3]: [H][1]\*[H][2].

[I][3]: [G][3]+[H][3].

[K][3]: [K][1]\*[K][2].

[L][3]: [L][1]\*[L][2].

[M][3]: [K][3]+[L][3].

For [M][3] to equal \$100 million, Scenario 2's net present value ([L][2]) must be such that the expected cash flow across both scenarios sum to \$100 million.

[J][3] and [N][3]: ATWACC = (Debt Portion \* Cost of Debt \* (1 - Tax Rate)) + (Equity Portion \* Cost of Equity). We assume 50% Debt/Equity proportions, 6% Cost of Debt, 25% Tax Rate, 10% Cost of Equity for Project B and 13.3% Cost of Equity for Project A to reflect the added risk of less cash flow.

[J][3]: ([A]\*[B]\*(1-[C])) + ([D]\*[E]).

2

3 **Q26. Do the same concepts of risk and higher expected return you illustrate above**4 **apply to disallowances that result in regulatory lag and asymmetric risks?**

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1 A26. Yes, they do. As noted earlier in the testimony, cost recovery disallowance results in  
2 regulatory lag, and it may even be an asymmetric risk, if the Company does not have a  
3 corresponding upside opportunity to balance the lost earnings from regulatory lag. In  
4 this case, investors will earn below the expected rate of return, which is the market-  
5 determined cost of capital. Only when the regulatory lag is fully removed (or when the  
6 allowed rate of return is increased high enough to compensate for the effects of  
7 regulatory lag), investors will have the opportunity to earn the cost of capital.

8

9 Below, I present another illustrative example to demonstrate how an asymmetric risk  
10 through regulatory lag affects investors' expected free cash flows and rate of return.

11

12 Consider that the Company consistently invests \$100 million every year on necessary  
13 capital projects. Now assume that 20 percent of each year's capital spend is subject to  
14 regulatory lag (for a variety of reasons, such as those discussed in witness Bruzzano's  
15 testimony), resulting in persistent annual under recovery of capital expenditures by 20  
16 percent. What this means is that each \$100 million investment recovers only \$80  
17 million in time, implying a 100 percent probability that \$20 million of regulatory lag  
18 ensues each year. Assume that there is no corresponding upside opportunity to balance  
19 the lost earnings from such a regulatory lag.

20

21 Figure 1 illustrates mathematically the effect of this regulatory lag on investors'  
22 expected free cash flows and required rate of return. As shown in Figure 1, investors'  
23 expected *ex ante* free cash flows will need to offset the \$20 million of persistent under  
24 recovery due to regulatory lag associated with each year's investment. The resulting  
25 required rate of return would need to be 10.90 percent, and the authorized ROE would

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1 have to be set at 17.3 percent to compensate for this risk to allow investors to earn their  
2 cost of capital.

3

4

**Figure 2 : Impact of Regulatory Lag on Expected Rate of Return**

|                                                                               | Probability<br>[1] | NPV<br>(\$M)<br>[2] | Embedded Cash<br>Flow (\$M)<br>[3] |
|-------------------------------------------------------------------------------|--------------------|---------------------|------------------------------------|
| <b>Capital Projects</b>                                                       |                    |                     |                                    |
| <b><u>Scenario 1</u></b> : Regulatory Lag Risk<br>(20 % of annual investment) | 100%               | 80.00               | 100.00                             |
| <b><u>Scenario 2</u></b> : Normal Cost Recovery<br>(no regulatory lag)        | 0%                 | 100.00              | -                                  |
| <b>Expected Cash Flow</b>                                                     |                    |                     | <b>100.00</b>                      |
| <b>Cost of Capital</b>                                                        |                    |                     | <b>10.89%</b>                      |
| <b>Allowed ROE</b>                                                            |                    |                     | <b>17.27%</b>                      |

5

6 **Summary and Conclusion**7 **Q27. Please summarize your testimony.**

8 A27. DTE Electric expects to make large investments rebuilding and reinforcing its aging  
9 electric distribution grid and investing in its power generation fleet and utility-scale  
10 energy storage to serve a growing demand for power. These needed investments also  
11 improve service quality for customers and are expected to provide substantial economic  
12 benefits. In its recent order in Case No. U-21534, the Commission disallowed certain  
13 capital expenditures the Company forecasted for 2024. Capital expenditure recovery  
14 disallowances on necessary investment increase regulatory risk for the Company.

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1 In the short-term, the Company has limited ability to address the adverse effects of  
2 higher risk without adversely impacting reliability and service quality. This increases  
3 regulatory lag, and certain expenditures that have been incurred will not be fully  
4 recovered. Regulatory lag may be an asymmetric risk, since the Company may not  
5 have a corresponding upside opportunity to balance the lost earnings due to the lag.  
6 Only when the regulatory lag is fully removed, investors will have the opportunity to  
7 earn the allowed rate of return.

8

9 Persistent disallowances increase the Company's regulatory risk. When faced with  
10 higher regulatory risk, investors' expected rate of return to fund the utility's future  
11 investments will increase, increasing its cost of capital. If the allowed ROE (or the  
12 equity ratios) were not subsequently adjusted to reflect the higher risk borne by  
13 investors, the Company would forgo the opportunity to earn its cost of capital. Capital  
14 attraction would be challenged, and in the long-run would lead to undercapitalization  
15 as the Company would be forced to scale back its long-term investment plans and  
16 reduce capital outlays, and increasing customer costs.

17

18 Higher regulatory risk also has a disproportionate impact on DTE Electric's earnings  
19 at a time the Company is planning large capital investments over the next several years.  
20 Large investments increase fixed costs, which increases business risk. Any additional  
21 risk associated with timely and/or full cost recovery thus will become even more  
22 significant.

23

24 The Company's credit quality will also be challenged as disallowances and recovery  
25 risks will serve to reduce cash flow to debt metrics (which are closely monitored by

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1 credit rating agencies), potentially risking credit rating downgrade. Overall, higher  
2 regulatory risk will make the Company more risky from investors' perspective,  
3 necessitating a higher allowed rate of return to attract investor capital and maintain the  
4 Company's financial health.

5

6 **Q28. Does this conclude your direct testimony?**

7 A28. 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-21860

QUALIFICATIONS  
AND  
DIRECT TESTIMONY  
OF  
WILLIAM H. LUDLOW



**DTE ELECTRIC COMPANY**  
**QUALIFICATIONS AND DIRECT TESTIMONY OF WILLIAM H. LUDLOW**

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

2   A1.   My name is William H. Ludlow, and I am employed by West Monroe Partners,  
3       LLC (“West Monroe”) as a Director in the Energy and Utilities practice (“E&U”).  
4       My West Monroe E&U business address is 729 Washington Ave N, Suite 200,  
5       Minneapolis, MN 55401.

6  
7   **Q2.   On whose behalf are you testifying?**

8   A2.   I am submitting testimony on behalf of DTE Electric (“DTE Electric” or the  
9       “Company”) before the Michigan Public Service Commission (the “Commission”  
10      or “MPSC”).

11  
12   **Q3.   What is your educational background?**

13   A3.   I graduated from the University of Michigan (Ann Arbor, MI) with a Bachelor of  
14      Arts in Economics. In addition, I received an MBA from Cornell University  
15      (Ithaca, NY).

16  
17   **Q4.   What work experience do you have?**

18   A4.   Over the past nine years, I have supported the development of cost-benefit analyses  
19      (“CBA”) in support of and execution of grid modernization programs at utilities  
20      across the United States. This experience has included project management  
21      activities including developing detailed implementation roadmaps, facilitating  
22      vendor qualification and selection processes, and measuring and verifying incurred  
23      costs and estimated benefits through the implementation process. As part of West  
24      Monroe’s Project Management capability, we are commonly responsible for  
25      developing and maintaining project budgets from project inception through

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1 completion. This experience, along with West Monroe's experience supporting  
2 utilities with similar filings across the country, has informed a robust approach to  
3 estimating costs, valuing projects, and quantifying the benefits that accrue to  
4 customers, utility operators, and society when implementing various grid  
5 technologies, systems, and transformation plans.

6

7 **Q5. What are your current duties and responsibilities?**

8 A5. As a Director for West Monroe's Energy and Utilities practice, I help electric  
9 utilities develop regulatory filings in support of proposed capital investments,  
10 prudence determinations, and recovery of prior spend. These efforts include  
11 estimating costs and benefits based on each utility's specific operating conditions,  
12 including specific regulatory obligations. A summary of my professional  
13 experience and education is included in Exhibit A-34 Schedule Y1.

14

15 **Q6. Have you been involved in any prior regulatory proceedings?**

16 A6. Yes. While I have not sponsored testimony before the MPSC, I have sponsored  
17 testimony in cases with electric utilities in other jurisdictions including the  
18 following:

19

20 24-0112-EL-GRD: AES Ohio Smart Grid Plan

21 PUR-2024-00137: Dominion Energy Virginia Rider DIST

22 2024-34-E: Dominion Energy South Carolina Electric Rate Case

23 PUR-2023-00051: Dominion Energy Virginia Grid Transformation Plan

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1 **Purpose of Testimony**

2 **Q7. What is the purpose of your testimony?**

3 A7. The purpose of my testimony is to summarize how the Company's cost forecasts in  
4 this proceeding should be interpreted, in conformance with industry standards for  
5 cost estimation. My testimony is organized as follows:

- 6 • Reasonableness of Company cost estimation methodologies
- 7 • Review of prior MPSC Staff interpretations of Company cost estimates
- 8 • Implication of MPSC Staff's use of the Association for the Advancement  
9 of Cost Engineering ("ACE") cost estimate classifications to establish  
10 disallowance thresholds
- 11 • The use of contingency as a cost estimation best practice for ratemaking  
12 purposes across utilities

13

14 **Q8. Please summarize the key findings and recommendations from this testimony.**

15 A8. There are several key findings and recommendations in my testimony that I would  
16 like to highlight:

- 17 • First, I assert that the ACE cost estimate classification Recommended  
18 Practices ("RP") cannot be reasonably or broadly applied as justification for  
19 disallowance of spend.
- 20 • Second, I find that MPSC Staff's past application of ACE cost estimate  
21 classifications is inconsistent with the fact that the Company excludes  
22 contingencies from its cost estimates. I also make suggestions as to how  
23 the Company's cost estimates should be regarded in the present and future  
24 rate cases.

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- 1           • Next, I observe that the method in which MPSC Staff has applied AACE
- 2           cost estimate classifications to justify disallowances from the Company's
- 3           forecasts from prior rate cases results in a high probability of under
- 4           recovery. As I will demonstrate in my testimony, the directional
- 5           consequence of these recommended disallowances is that actual costs will
- 6           exceed the Company's approved cost allowances with greater than 90%
- 7           confidence. While actual expenditures may ultimately be recovered in a
- 8           subsequent rate case if found to be prudent the Company experiences
- 9           “regulatory lag”, as discussed in more detail by Company Witness
- 10          Bruzano.
- 11          • I conclude my testimony with a recommendation that the Commission no
- 12          longer apply a disallowance to proposed investments based on AACE cost
- 13          estimate classification standards.

14

15   **Q9. Are you sponsoring any exhibits in this proceeding?**

16   A9. Yes. I am sponsoring the following exhibits:

17          Exhibit      Schedule   Description

18          A-34           Y1       Background and Qualifications of William H. Ludlow

19          A-34           Y2       Summary of the AACE Cost Estimate Classification System

20

21   **Reasonableness of DTE Electric Cost Estimation Methodologies**

22   **Q10. What processes and methodologies are in use across the Company's business**

23       **units in support of developing cost estimates?**

24   A10. The testimonies of Company Witnesses Ambrose, Davis, and Guillaumin define

25       the business unit-specific cost estimation methods in use by the Company.

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1   **Q11. In your opinion, are the Company’s stated cost estimation methodologies**  
2       **reasonable for purposes of rendering informed, risk-adjusted cost estimates?**

3   A11. Yes. I believe the Company’s utilization of business unit-specific cost estimation  
4       approaches is reasonable given the unique needs and knowledge required to manage  
5       each business unit. The IT investment selection and approval process is designed  
6       to support their ever-evolving environment and technology needs as discussed by  
7       Witness Ambrose. For Nuclear, Witness Davis provides further explanations of  
8       delivering outcomes consistent with Fermi 2’s operating priorities and accuracy to  
9       the total. For Energy Supply, Witness Guillaumin elaborates on the Project  
10      Approval Team (“PAT”) stage gate approval process highlighting the robustness of  
11      each stage and the requirements to progress through the approval process. Please  
12      refer to the Company Witness testimonies for additional details.

13

14   **Q12. Has the Company included contingencies in the forecasts included in this**  
15       **electric rate case?**

16   A12. No. It is my understanding that the MPSC has taken a position that contingencies  
17       be disallowed from inclusion in rate case cost forecasting, stating “As the  
18       Commission has repeatedly found, although allowing for contingency may be  
19       appropriate in project planning, the inclusion of these costs in customer rates is  
20       unjust and unreasonable.<sup>1</sup>” In accordance with the MPSC’s guidance, the Company  
21       has chosen to exclude cost contingencies in the forecasts included in this

---

<sup>1</sup> Case No. U-20162; See also Case No. U-20940 where the Commission goes on to say “The Commission agrees with the ALJ that contingency is a forward looking, forecasted amount added to a budget to address unknown and unforeseen events. Once an amount has been spent, however, it is no longer a contingency but rather an actual expenditure and becomes subject to the reasonableness and prudence review that all actual expenditures undergo.”

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1 proceeding. As I will argue subsequently in my testimony, it would be reasonable  
2 for the Company to include contingencies in its cost estimates.

3

4 **Q13. How should the concept of confidence intervals be applied to the Company's**  
5 **cost estimates?**

6 A13. First, assessing confidence intervals of the Company's cost estimates should  
7 consider that the amount for appropriate contingency is not included. As a result,  
8 these estimates are already skewed towards the lower end of any accuracy range  
9 that might attempt to determine the range of actual project cost. Second, an analysis  
10 of the risks must be performed to determine the project-specific risk and the  
11 expected accuracy of estimates. These risks, if evaluated consistently with AACE  
12 RP 18R-97, are detailed in my Exhibit A-34, Schedule Y2, Summary of the AACE  
13 Cost Estimate Classification System, and include technology familiarity, project  
14 complexity, project novelty, estimating techniques used, and more. I have not  
15 completed an assessment of the risks associated with the Company's proposed  
16 projects in this instant proceeding; however, it is worth noting that many utility  
17 projects are routine and repetitive, located in familiar locations, and reliant on  
18 established supply chains. While utility projects can include complex or relatively  
19 novel technologies, these projects are rarely without precedent in the industry.  
20 Directionally, utility projects, such as those included in this proceeding, are subject  
21 to lower systemic risks which, if AACE's range of accuracy ranges were to be  
22 assigned, a narrow band within the prescribed range of ranges would be logical.

23

24 **Q14. Is it appropriate to apply AACE RP 18R-97 to the cost estimates prepared by**  
25 **each of the Company's business units in this proceeding?**

Line  
No.

1 A14. No. While AACE RP 18R-97 applies to process industries, which it defines to  
2 include utilities, among other industries, it explicitly states that this RP “excludes  
3 power generating facilities and high-voltage transmission,” “does not address cost  
4 estimate classification in non-process industries such as...software development,”  
5 and that “the cost estimates covered by this RP are for engineering, procurement,  
6 and construction (“EPC”) work only.”<sup>2</sup> For these reasons, among other nuances  
7 described in this testimony, it would be inappropriate to apply AACE RP 18R-97  
8 to projects executed by the Company’s IT and Fermi business units.

9

10 **Review of Prior Commission Interpretation of DTE Electric Cost Estimates**

11 **Q15. Have AACE classifications been applied to DTE Electric projects in previous**  
12 **rate cases?**

13 A15. Yes. Most recently, as referenced in Case No. U-21534 order (“Order”), the AACE  
14 Cost Estimate Classifications from RP No. 18R-97 for EPC work for the Process  
15 Industries were applied by Staff to Energy Supply, Information Technology (IT),  
16 and Fermi projects to assert the certainty of proposed investments in response to  
17 previous timing variances in spend.

18

19 **Q16. How were AACE classifications applied to DTE Electric Energy Supply**  
20 **projects in previous rate cases?**

21 A16. The AACE Class 4 and Class 5 were assigned to Energy Supply projects for 2024  
22 and 2025, respectively, as described on page 42 of the Order. The Order goes on  
23 to say, on page 43, that “[t]he Staff states that it used the AACE ranges as a general  
24 guide and applied the lowest possible recommended adjustment for Class 4 and 5

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<sup>2</sup> AACE International. 18R-97 Cost Estimation Classification System - As Applied in Engineering, Procurement, and Construction for the Process Industries. AACE International, 2020. Page 2

Line  
No.

1 cost estimates, which takes into consideration that contingency has already been  
2 removed.” MPSC Staff’s assignment of AACE Class was based primarily on  
3 timing of projects, with projects to be completed in 2024 receiving a Class 4  
4 designation and those to be completed in 2025 receiving a Class 5. This use of  
5 timing to assign AACE classifications is mis-aligned with AACE’s prescribed  
6 methodology, which requires an assessment of the maturity of project planning and  
7 design artifacts. The Commission acknowledges on page 43 of the Order, “Staff  
8 states that it was not privy to how the Company arrived at its ranges or developed  
9 its cost estimates.” It is worth noting that the DTE Electric Energy Supply team was  
10 not using the AACE classification system and thus would not necessarily have the  
11 requisite information readily available. Instead, it uses a documented, internally  
12 derived system comprising three levels to define and assign project maturity. The  
13 Commission, on pages 44 and 45 of the final order, found MPSC Staff’s proposal  
14 reasonable. After application, the treatment was justified by claiming that a few  
15 months of underspend indicates a pattern revealing projections that “are either  
16 potentially overinflated to begin with, are not meeting projected schedules and  
17 spending milestones, or have cost reductions for other reasons compared to when  
18 the Company prepared it[s] forecast.” The Company argues in the Rebuttal  
19 Testimony of Witness Guillaumin (pg. 11) in Case No. U-21534 that the variances  
20 seen over just a few short months do not provide evidence to the reasonableness  
21 and prudence of those projects. Witness Guillaumin describes these variances as  
22 simply related to timing and the Company expects their portfolio of projects to meet  
23 the overall projected spend.



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1   **Q17. How were AACE classifications applied to DTE Electric IT projects in**  
2       **previous rate cases?**

3   A17. The AACE Class 1 and AACE Class 3 were assigned to IT projects based on high-  
4       level understanding of the maturity of the scope, cost, and schedule. It is worth  
5       noting that the DTE Electric IT team does not use the AACE classification system;  
6       rather, it uses a documented, internally-derived system comprising three levels to  
7       define and assign project maturity.

8

9   **Q18. How were AACE classifications applied to DTE Electric Nuclear Generation**  
10       **projects in previous rate cases?**

11   A18. The AACE Class 4 and AACE Class 5 were assigned to Fermi projects projected  
12       for 2024 and 2025 respectively. Similar to Energy Supply investments, this  
13       assignment was based primarily on the timing of projects and further justified by  
14       evidence of underspend over a 5-month period. The Company argues in rebuttal  
15       testimony that the underspend referenced represents reasonable and temporary  
16       timing variances rather than evidence of permanent underspend. This was  
17       reinforced by the Company and acknowledged by the Commission (See U-21534  
18       Order p. 57), with evidence provided in Exhibit A-47, Schedule LL1 that included  
19       3 additional months of capital expenditure showing actual expenditures of \$160.4  
20       million and planned expenditures of \$162.8 million, which equates to a variance of  
21       less than 2%.

22

23   **Q19. Do you agree with the application of AACE classifications to DTE Electric**  
24       **projects?**

Line  
No.

1 A19. No. MPSC Staff applied AACE Cost Estimate Classifications from RP No. 18R-  
2 97 on projects, to which this RP does not apply, as I described earlier in my  
3 testimony. AACE RP No. 18R-97 should not be applied to nuclear (i.e., Fermi)  
4 projects given it explicitly excludes power generating facilities. Further, there is  
5 no AACE RP applicable to IT projects, as these classification systems are all  
6 associated with engineering, procurement, and construction activities for industrial  
7 projects. The unique project components and design artifacts used for nuclear and  
8 IT projects fall outside of the scope of this document. The application of AACE  
9 classifications to Energy Supply projects was based on the timing of projects, which  
10 does not follow the methodology detailed by AACE.

11

12 **Q20. How has the concept of AACE accuracy ranges been applied to the Company's**  
13 **estimates in previous rate cases?**

14 A20. Most recently, in the Order for Case No. U-21534, the reductions derived from  
15 AACE RP No. 18R-97 Estimated Accuracy Ranges were applied to Energy Supply  
16 (pg. 42), Fermi (pg. 56), and IT (pgs. 183-187) projects. In these instances, MPSC  
17 Staff applied the accuracy range to estimates that exclude contingency and limited  
18 the allowance to the lower bound of the range, which effectively resulted in  
19 allowance of costs less than the lower bound of the AACE accuracy range, as  
20 depicted in my Figure 3 below. For certain projects, the disallowance was  
21 supported by examining a small sample size (a few months) of actual spend data  
22 that was below forecasts.

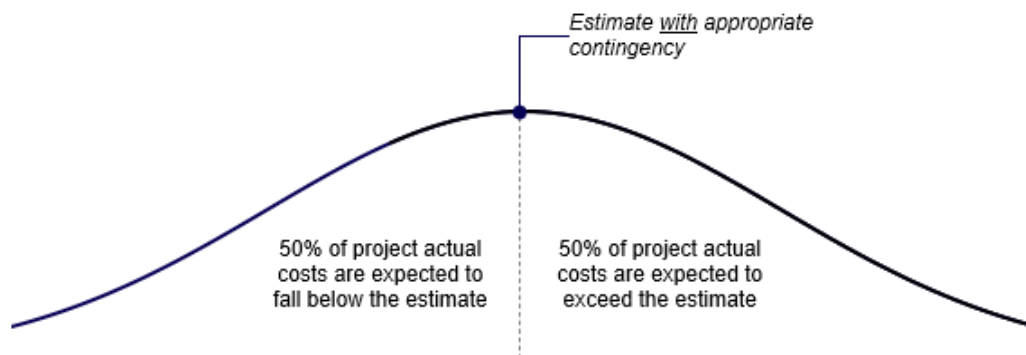
23

24 **Q21. Do you agree with the application of AACE Expected Accuracy Ranges on the**  
25 **Company's cost estimates?**

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No.

1 A21. No, for several reasons. First, the use of a small sample size of project actuals as  
2 justification for anchoring a specific level of spend expectation is not aligned with  
3 AACE's recommended determination of accuracy ranges and does not replace the  
4 assessment of risk that AACE calls for to determine an appropriate range. Second,  
5 prior Commission orders that cite use of AACE's Expected Accuracy Ranges, most  
6 recently in Case No. U-21534, does not reflect any consideration of the fact that  
7 AACE's Expected Accuracy Ranges include both a lower bound and an upper bound,  
8 as depicted in my Figure 1 below.

10 **Figure 1 AACE Expected Accuracy Depiction**

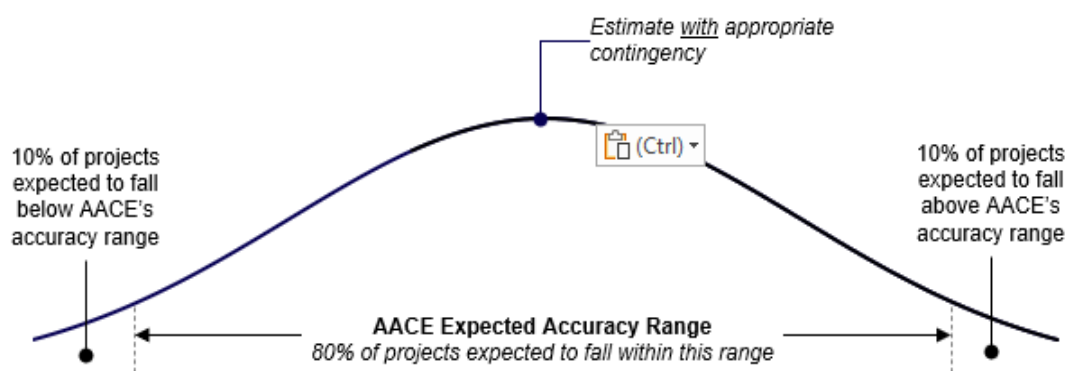


11  
12 Instead, lower bounds appear to have been considered, in isolation, to justify the  
13 disallowance. In fact, in the Rebuttal Testimony of Company Witness Pankaj  
14 Sharma (pg. 4) in Case No. U-21534, the Company states that "Staff Witness  
15 Rogers' selection and recommendation of the lowest accuracy range provided for  
16 Class 3 estimates fails to consider that the AACE Class 3 estimates also provide an  
17 upper range for Class 3 estimates at +30%." AACE 18R-97 states that the  
18 percentage ranges of certainty tied to each Estimate Class (1-5) represent "typical

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percentage variation at an 80% confidence interval of actual costs from the cost estimate after application of appropriate contingency.” The ranges, by class, can be found in Exhibit A-34 Y2 of my testimony. The confidence level of projects falling within those ranges is represented in Figure 2, which assumes that the probability of outcomes follows a normal distribution.

**Figure 2 AACE Expected Accuracy Range Depiction**

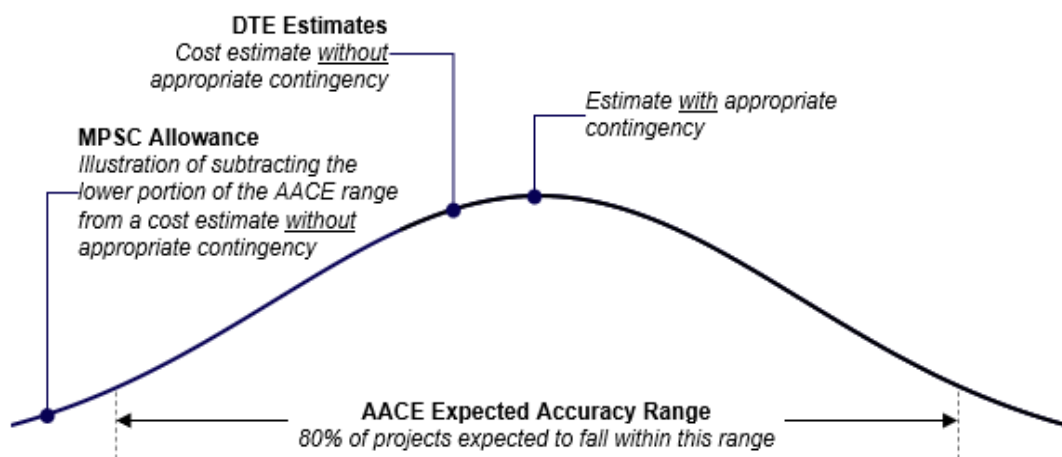


As noted previously, the Company does not and cannot include contingency in its cost estimates for ratemaking purposes. Therefore, the cost estimates provided by the Company already skew towards the lower half of the probability distribution, and subtraction of the lower bound of AACE’s Expected Accuracy Range from a pre-contingency estimate results in an allowance *below* the lower bound of AACE’s Expected Accuracy Range. This results in a situation in which there is less than 10% confidence of MPSC allowances being sufficient to account for the full cost of DTE’s projects, as depicted in Figure 3.

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1

**Figure 3 MPSC Application of AACE Lower Bound Depiction**



2

3 **Q22. Did the Company address in prior testimony how confidence intervals were**  
4 **applied to Company cost estimates that did not include contingency?**

5 A22. Yes. In the Rebuttal Testimony of Margaret Guillaumin (pgs. 14-15) in Case No.  
6 U-21534, the Company states that the AACE-derived confidence intervals did not  
7 apply to Company projections that did not include contingency. Witness  
8 Guillaumin argued that using the Company's projections that already exclude  
9 contingency as the baseline with which to determine a range of expected project  
10 costs is inconsistent with AACE Recommended Practices and includes calculations  
11 detailing the impact of this methodology. In the Rebuttal Testimony of Jeff Davis  
12 (pg. 11) in Case No. U-21534, the Company makes note of the inconsistency  
13 between AACE's Recommended Practice and MPSC application of AACE  
14 accuracy ranges to capital expenditures that exclude contingency.

15

16 **Q23. Did the Commission acknowledge such application of confidence intervals in**  
17 **its order within the Company's prior rate case?**

Line  
No.

1 A23. Yes. On page 43 of the Order for Case No. U-21534, the Commission did  
2 acknowledge that confidence intervals intended for use on estimates that include  
3 contingency were applied to DTE Electric project estimates, which do not include  
4 contingency. It then, however, failed to apply those confidence intervals in a  
5 manner consistent with AACE Recommended Practices, which should consider  
6 inclusion, or lack thereof, of contingency. On the same page, the Order goes on to  
7 say, “Staff states that it used the AACE ranges as a general guide and applied the  
8 lowest possible recommended adjustment for Class 4 and 5 cost estimates, which  
9 takes into consideration that contingency has already been removed.” The “lowest  
10 possible recommended adjustment” appears to refer to the narrowest band within  
11 the range of ranges provided by AACE.

12

13 **Q24. Do you agree with MPSC Staff’s interpretation of AACE ranges as a general**  
14 **guide?**

15 A24. No. AACE’s range of ranges exist to attempt to account for variable risk, not  
16 contingency, and should not be interpreted as “recommended” adjustments. Even  
17 this narrow band assumes project estimates include contingency, and selecting the  
18 lower end of the range does not justify the overall misapplication of AACE as a  
19 reason for disallowance.

20

21 **Q25. Do you believe that any use of confidence intervals must account for the fact**  
22 **that the Company has not included contingency in its estimates this**  
23 **proceeding?**

24 A25. While I do not believe that AACE is an appropriate measure of the Company’s cost  
25 estimate accuracies discussed herein, nor that it should be used as a proxy for

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1 disallowances, if the Commission continues to accept its use, then contingency  
2 estimates should be explicitly considered based on estimates provided directly by  
3 the Company's business units. The Company has not included cost contingencies  
4 in the forecasts included in this proceeding. Therefore, any application of  
5 confidence intervals to assess the Expected Accuracy Range of the Company's cost  
6 estimates should account for that and should also consider that AACE ranges  
7 contemplate the potential that the project will require expenditures above the  
8 projection.

9

10 **Impact of Recent Application of AACE Expected Accuracy Ranges to DTE Electric**  
11 **Projects**

12 **Q26. Using AACE's classification system, what is the probability of a project's**  
13 **actual cost exceeding the level awarded by the Commission in recent years?**

14 A26. The revenue allowances that have been awarded to the Company in recent years,  
15 net of disallowances justified through application of AACE to estimates that do not  
16 include contingency, should be expected to be insufficient with a greater than 90%  
17 confidence, per AACE, as described in Figure 2 and the hypothetical scenario  
18 detailed below. Within the AACE system, the inclusion of contingency is required  
19 to determine an estimate with a 50% probability of project cost overrun versus  
20 underrun for a given scope. Lack of consideration of contingency results in a  
21 situation where AACE's ranges do not accurately depict the expected variability in  
22 project costs. Figures 4 through 6 below illustrate this point.

23 Figure 4 introduces a hypothetical project with a cost estimate of \$100, excluding  
24 appropriate contingency, which is assumed to be 10%. As depicted, a total estimate

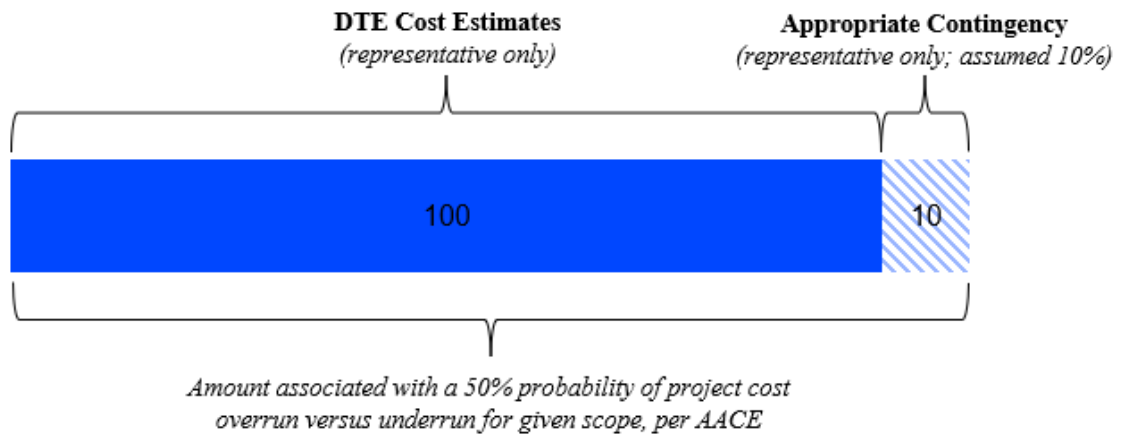
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1 of \$110 would be associated with a 50% probability of project cost overrun versus  
2 underrun for a given scope, per AACE's estimate classification system.

3

4

**Figure 4 Depiction of DTE Estimates without Contingency**



5

6 An appropriate interpretation of AACE's Expected Accuracy Ranges would apply  
7 the lower and upper bounds to the total cost estimate, inclusive of contingency,  
8 which is \$110 in this example. Assuming a Class 1 estimate using AACE RP 18R-  
9 97 and applying the broadest applicable Expected Accuracy Range associated with  
10 Class 1, the lower and upper bounds associated with an 80% confidence level would  
11 equal -10% and +15%, respectively. Outside of this 80% confidence interval, there  
12 exists a 10% probability of actual project costs falling below the range and a 10%  
13 probability of actual project costs exceeding the range. Therefore, there exists a  
14 90% probability (80% confidence interval of range + 10% probability of exceeding  
15 the range) that the project's actual cost would exceed the lower bound. Figure 5  
16 depicts how this concept applies to this hypothetical scenario, with a lower and  
17 upper bound for our hypothetical project of \$99 and \$126.50, respectively. In this



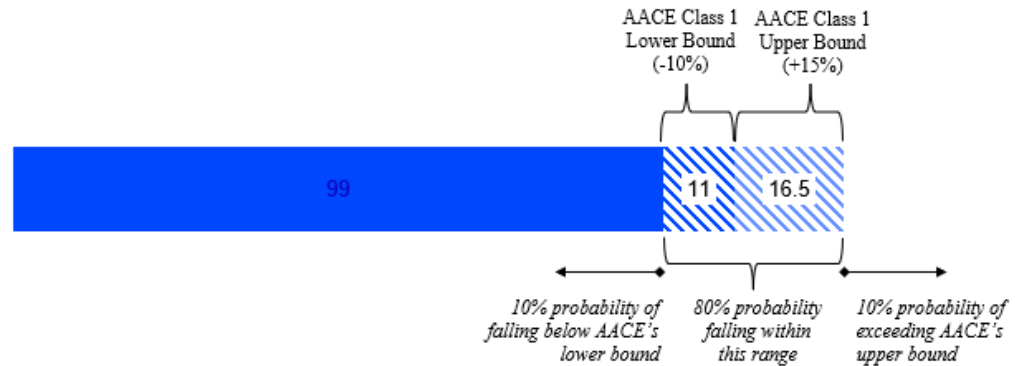
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1 hypothetical scenario, this should be interpreted as a 90% confidence that actual  
2 project costs would exceed \$99.

3

4

**Figure 5 Depiction of AACE Estimated Accuracy Ranges**



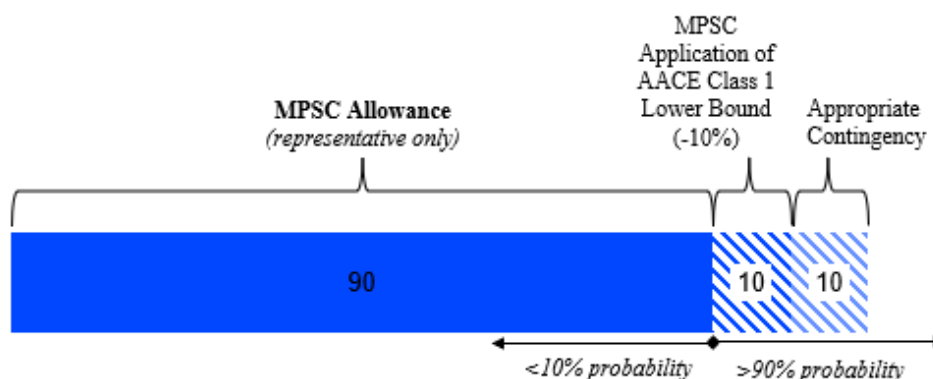
5

6 If one were to calculate AACE's -10% lower bound from a pre-contingency  
7 estimate of \$100 instead of a post-contingency estimate of \$110, the lower bound  
8 of AACE's expected accuracy range would inaccurately be set to \$90 instead of  
9 \$99. As mentioned above, there exists a *greater than 90%* probability that project actuals exceed  
10 \$99. As such, there exists a *greater than 90%* probability of exceeding any amount  
11 below \$99. Said another way, there exists a less than 10% probability of an estimate  
12 of \$90 being sufficient to account for the full cost of the project, as depicted in  
13 Figure 6.

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1

**Figure 6 Depiction of MPSC Application of AACE Lower Bound**



2

3 This scenario explained above is illustrative of my interpretation of past  
4 disallowances of the Company's rate base. The approved rate base allowances  
5 suggest, in the context of AACE estimate accuracy range application, a greater than  
6 90% probability of actual spend exceeding the allowed amounts for projects  
7 otherwise deemed prudent.

8

9 **Q27. How should AACE Expected Accuracy Ranges be assessed to determine a**  
10 **reasonable cost estimate?**

11 A27. A reasonable cost estimate is one that, after accounting for contingency, balances  
12 the probability that the cost of a project may come in above or below the level that  
13 is projected. If applied in relation to the cost estimates sought in the Company's  
14 instant application, this treatment would result in fair recovery over time. It should  
15 be noted that appropriate contingency can be quantified by a number of methods,  
16 as long as it represents the aggregate risk and uncertainty associated with the  
17 project, as defined by leading industry associations detailed above.

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1 **Use of Contingency in Utility Cost Estimation**

2 **Q28. Is the use of contingency considered a best practice in utility project cost**  
3 **estimation among industry associations?**

4 A28. Yes. Numerous industry associations, including the U.S. Department of Energy  
5 (“DOE”), Project Management Institute (“PMI”), and AACE consider contingency  
6 a necessary component of project cost estimation.

- 7 • **U.S. Department of Energy (DOE):** The DOE utilizes a directive document  
8 to “guide the acquisition of capital assets with the goal of delivering projects  
9 within the original performance baseline (PB), cost and schedule, and fully  
10 capable of meeting mission performance, safeguards and security, and  
11 environmental, safety, and health requirements execution of their projects”<sup>3</sup>.  
12 This directive and others referenced within include the methodologies to  
13 develop a project baseline cost, which explicitly includes contingency. The  
14 DOE asserts that “Contingency management should be an integral part of the  
15 DOE capital asset project risk management process, providing project managers  
16 with the tools to respond to project risks and uncertainties that are inherent in  
17 all DOE projects”<sup>4</sup>. The DOE outlines a quantitative contingency analysis  
18 based on a detailed risk assessment, whose purpose is “to provide budget and  
19 completion date estimates that include the effects of the project risks and other  
20 project uncertainties using statistical modeling techniques such as Monte Carlo  
21 analyses or other similar methodologies.”

---

<sup>3</sup> U.S. DOE Program and Project Management for the Acquisition of Capital Assets, available at <https://www.directives.doe.gov/directives-documents/400-series/0413.3-BOrder-B-chg7-ltdchg/@@images/file>, accessed March 24, 2025

<sup>4</sup> U.S. DOE Risk Management Guide, available at <https://www.directives.doe.gov/directives-documents/400-series/0413.3-EGuide-07a-chg2-ltdchg/@@images/file>, accessed March 24, 2025

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- 1       • **Project Management Institute (PMI):** In a 2012 conference paper entitled  
2       “Contingency—are you covered?”, PMI investigates the value of contingency  
3       and how it should be quantified. It states that the use of contingency budgets  
4       can improve transparency, provide a more realistic business case and cash  
5       flows, and discourages potentially harmful tradeoffs in schedule and/or scope  
6       and functionality. PMI claims that having no contingency limits the project  
7       team’s ability to problem solve. The total contingency is defined as the sum of  
8       the estimate uncertainty, from uncertainties inherent to the estimating process,  
9       minor errors in putting estimates together, and the risk contingency. PMI  
10      contemplates a detailed risk analysis needing to be conducted to determine the  
11      financial impacts of probabilities of risks and states, "Contingency budgets are  
12      built on a detailed understanding of the project's risks—including the likelihood  
13      they will be realized and the cost of a response plan."<sup>5</sup> PMI references the  
14      AACE Expected Accuracy Ranges as a proxy for estimate uncertainty. It then  
15      contemplates analysis via a Monte Carlo simulation to determine the likelihood  
16      that the actual project budget falls above or below forecast amounts with and  
17      without contingency.
- 18      • **AACE International:** In its Cost Estimate Classification Systems, AACE  
19      presents Expected Accuracy Ranges depicting typical variation in estimate  
20      accuracy *after* the application of appropriate contingency that achieves a 50%  
21      probability of project cost overrun versus underrun. AACE assumes use of  
22      contingency that is capable of “appropriately quantifying the uncertainty and

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<sup>5</sup> England, K. & Moreci, J. (2012). *Contingency—are you covered? Paper presented at PMI® Global Congress 2012—North America, Vancouver, British Columbia, Canada. Newtown Square, PA: Project Management Institute.*

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1 risks associated with the cost estimate”<sup>6</sup>. The range of certainty that AACE  
2 applies to an investment, which reflects equal probabilities of overspend and  
3 underspend, is contemplated after contingency has been factored into the cost  
4 forecast.

5

6 **Q29. Do other jurisdictions within the United States allow for inclusion of**  
7 **contingencies in cost forecasts to be included in utility rates?**

8 A29. Yes, there are several examples of jurisdictions allowing for the inclusion of cost  
9 contingencies:

- 10 • **Indiana:** The Indiana Utility Regulatory Commission (“IURC”) deemed  
11 contingency “reasonable to account for the unexpected”<sup>7</sup>. Contingency is  
12 necessary because “removing contingency costs could lead to intergenerational  
13 inequity that is not recovered as part of the full service value of the assets”.
- 14 • **Minnesota:** In Minnesota, the Minnesota Public Utilities Commission  
15 (“MPUC”) approved budget for a Transmission Cost Recovery Rider (\$104  
16 million) in 2023 which includes contingency budget in the forecast for  
17 Advanced Distribution Management Systems and Field Area Network  
18 projects<sup>8</sup>.
- 19 • **Ohio:** In Ohio, the Public Utilities Commission of Ohio (“PUCO”) ordered that  
20 10% margin of error was appropriate for a gridSMART Capital and O&M  
21 budget<sup>9</sup>.

---

<sup>6</sup>AACE International. *18R-97 Cost Estimation Classification System - As Applied in Engineering, Procurement, and Construction for the Process Industries*. AACE International, 2020.

<sup>7</sup> Indiana Utility Regulatory Commission, Order in Cause No. 46038, January 29, 2025, pp. 62-63

<sup>8</sup> Minnesota Public Service Commission, Order in Docket NO. E-002/M-21-814 Order, June 28, 2023

<sup>9</sup> Public Utilities Commission of Ohio, Case No. 19-1475-EL-RDR, December 1, 2021, pp. 7

Line  
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1   **Q30. Are you aware of regulated utilities that include contingencies in cost forecasts**  
2           **as proposed and approved by regulators within rate cases or similar**  
3           **regulatory proceedings?**

4   A30. Yes. Below are three such examples:

- 5           • **Duke Energy Indiana:** In the context of Coal Combustion Residual  
6           ("CCR") demolition projects contingency budget is added as 20% of direct  
7           costs based on real world examples and best practices of similar projects,  
8           and IURC precedent. Contingency costs account for these unspecified but  
9           expected costs and are in addition to the direct costs.<sup>10</sup>
- 10          • **Xcel Energy:** Contingency is included in project forecasts and is refined as  
11          the project progresses. The use of contingency is closely managed and  
12          subject to internal approvals. Cost-Benefit Analysis is presented both with  
13          and without contingency budgets.<sup>11</sup>
- 14          • **American Electric Power ("AEP") Ohio:** A 10% margin of error was  
15          added on to Capital and O&M spend for AEP Ohio's gridSMART Plan in  
16          Case No. 19-1475-EL-RDR. Capital spend was capped at \$223 million,  
17          with contingency the total cost cap is \$245 million. O&M spend was  
18          capped at \$78 million with total cost cap at \$86M.<sup>12</sup>

19  
20   **Q31. In your opinion, is the inclusion of contingency in cost estimates embedded in**  
21           **utility rates considered a best practice?**

---

<sup>10</sup> Indiana Utility Regulatory Commission, Order in Cause No. 46038, January 29, 2025, pp. 57

<sup>11</sup> Minnesota Public Service Commission, Docket No. E-002/M-21-814 Petition for Transmission Cost Recovery Rider

<sup>12</sup> Public Utilities Commission of Ohio, Order in Case No. 19-1475-EL-RDR Order, December 1, 2021, paragraph 23

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1 A31. Yes. Guidance from utility industry associations, examples from other utilities and  
2 jurisdictions, and my own experience with project management and that of my  
3 colleagues leads me to believe that the use of contingency is fair and reasonable to  
4 include in cost estimates and consequently, in MPSC allowances for rate-setting  
5 purposes.

6

7 **CONCLUSION**

8 **Q32. What are the key conclusions and recommendations from your testimony?**

9 A32. I find that based on both prior Commission orders and current Company practices,  
10 it is important that this Commission revisit its interpretation of Company estimates  
11 and fully account for the fact that contingencies are not included in the Company's  
12 projections. In particular, I recommend discontinuing the use of AACE Expected  
13 Accuracy Ranges to assign a disallowance to Company cost estimates.

14

15 **Q33. Should the Commission approve the Company's forecasts as requested in this**  
16 **case if the bases of the amounts requested are found to be reasonable and**  
17 **prudent?**

18 A33. Yes.

19

20 **Q34. What recommendation, if any, do you have for the Commission with respect**  
21 **to the treatment of contingency in cost estimation?**

22 A34. While the Company has not included contingency in its cost estimates for the  
23 instant proceeding, I recommend that the Commission in future proceedings  
24 explicitly allow for the inclusion of contingency in cost allowances. As discussed

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1 previously, my recommendation is supported by best practices as well as precedent

2 throughout the country.

3

4 **Q35. Does this conclude your testimony?**

5 A35. Yes, it does.



**STATE OF MICHIGAN**  
**BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION**

|                                                 |   |                  |
|-------------------------------------------------|---|------------------|
| In the matter of the Application of             | ) |                  |
| <b>DTE ELECTRIC COMPANY</b>                     | ) |                  |
| For authority to increase its rates, amend      | ) | Case No. U-21860 |
| Its rate schedules and rules governing the      | ) |                  |
| Distribution and supply of electric energy, and | ) |                  |
| For miscellaneous accounting authority.         | ) |                  |

QUALIFICATIONS  
AND  
DIRECT TESTIMONY  
OF  
TIMOTHY S. LYONS

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| <b>V.</b>   | <b>RECENT COMMISSION DECISION.....</b>                                     | <b>10</b> |
| <b>VI.</b>  | <b>DTE ELECTRIC’S COST TRENDS RELATED TO MATERIALS AND<br/>LABOR .....</b> | <b>13</b> |
| <b>VII.</b> | <b>CONCLUSION .....</b>                                                    | <b>17</b> |

**DTE ELECTRIC COMPANY**  
**QUALIFICATIONS AND DIRECT TESTIMONY OF TIMOTHY S. LYONS**

Line  
No.

1    **I.    INTRODUCTION**

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

3    A1.    My name is Timothy S. Lyons. My business address is 3 Speen Street, Suite 150,  
4           Framingham, Massachusetts 01701. I am a Partner with ScottMadden, Inc.

5

6    **Q2.    On whose behalf are you testifying?**

7    A2.    I am submitting this testimony on behalf of DTE Electric Company (“DTE  
8           Electric” or the “Company”) before the Michigan Public Service Commission (the  
9           “Commission”).

10

11   **Q3.    What is your educational background?**

12   A3.    I hold a bachelor’s degree from St. Anselm College, a master’s degree in economics  
13           from The Pennsylvania State University, and a master’s degree in business  
14           administration from Babson College.

15

16   **Q4.    What is your professional experience?**

17   A4.    I have more than 30 years of experience in the utility industry. I started my career  
18           in 1985 at Boston Gas Company, eventually becoming Director of Rates and  
19           Revenue Analysis. In 1993, I moved to Providence Gas Company, eventually  
20           becoming Vice President of Marketing and Regulatory Affairs. Starting in 2001, I  
21           held management consulting positions in the energy industry first at KEMA and  
22           then at Quantec, LLC. In 2005, I became Vice President of Sales and Marketing at  
23           Vermont Gas Systems, Inc. before joining Sussex Economic Advisors, LLC  
24           (“Sussex”) in 2013. ScottMadden acquired Sussex in 2016. A summary of my  
25           professional experience and education is included in Exhibit A-32 Schedule V1.

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1   **Q5.   Have you been previously sponsored testimony before the Michigan Public**  
2           **Service Commission?**

3   A5.   Yes. I sponsored testimony in Case Nos. U-21490, U-21308, U-20650, U-20322,  
4           and U-18010. I have also sponsored testimony before more than 30 U.S. and  
5           Canadian regulatory agencies.

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1    **II.    PURPOSE OF TESTIMONY**

2    **Q6.    What is the purpose of your testimony?**

3    A6.    The purpose of my testimony is to support the Company's use of constant dollar  
4           averaging to develop its cost forecasts. Specifically, my testimony demonstrates  
5           that constant dollar averaging is consistent with economic principles, ensures cost  
6           forecasts adjust for inflationary trends, and is a recognized practice in developing  
7           cost forecasts.

8

9    **Q7.    Are you sponsoring any exhibits in this proceeding?**

10   A7.    Yes. I am sponsoring the following exhibit:

| <u>Exhibit</u> | <u>Schedule</u> | <u>Description</u>                                           |
|----------------|-----------------|--------------------------------------------------------------|
| A-32           | V1              | Professional Experience and Education of Timothy<br>S. Lyons |

14

15   **Q8.    Were these exhibits prepared by you or under your direction?**

16   A8.    Yes, they were.

17

18   **Q9.    Please summarize your testimony.**

19   A9.    Constant dollar averaging of historical costs – or inflation adjusting of historical  
20           costs – is a necessary step in developing cost forecasts because inflation over time  
21           reduces the purchasing power of goods and services. That is, if cost forecasts  
22           assume the dollars spent in the future are the same exact dollars spent in the past,  
23           then cost forecasts will yield fewer goods and services that can be purchased in the  
24           future due to inflation. In other words, if the same volume of goods and services

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1           were used in the future – primarily, materials and labor – they would cost more  
2           because of inflation.

3  
4           The Company’s Distribution Operations (DO) cost forecast relies on historical  
5           costs that are inflation-adjusted through constant dollar averaging to reflect cost of  
6           goods and services to be purchased in the future. Absent such inflation adjustment  
7           through constant dollar averaging, the Company will be unable to purchase in the  
8           future the same volume of goods and services – or perform the same volume of  
9           work – as in the past.

10  
11          Developing forecasts based on constant dollar averaging is a recognized practice in  
12          cost forecasting and financial planning. The Department of Defense (DoD) and the  
13          Government Accountability Office (GAO), for example, rely on inflation-adjusted  
14          historical costs to achieve cost forecasting integrity and fiscal accountability. In  
15          the utility industry, several jurisdictions including California, Oregon, and  
16          Massachusetts have recognized the necessity of constant dollar averaging of  
17          historical costs.

18  
19          In the Company’s most recent rate case proceeding, the Commission expressed  
20          concern that certain DO cost categories demonstrated cost variability without  
21          necessarily demonstrating a consistent upward trend in costs that would indicate  
22          inflation. As a result, the Commission denied Company’s use of constant dollar  
23          averaging to develop certain cost forecasts.

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1 This testimony demonstrates there is an upward trend in material and labor costs  
2 that reflects inflation, supporting the Company's use of constant dollar average to  
3 develop its cost forecasts.

4

5 **Q10. How is the remainder of your testimony organized?**

6 A10. The remainder of my testimony includes the following sections:

7 Section III Economic Justification for Inflation Adjustments

8 Section IV Constant Dollar Averaging as a Recognized Practice

9 Section V Recent Commission Decision

10 Section VI DTE Electric's Cost Trends related to Materials and Labor

11 Section VII Conclusion

12

13 **III. ECONOMIC JUSTIFICATION FOR INFLATION ADJUSTMENTS**

14 **Q11. How does constant dollar averaging adjust for inflation?**

15 A11. Constant dollar averaging adjusts historical costs upward to reflect current (or  
16 constant) dollar values. The approach, in effect, converts actual "nominal" dollars  
17 to constant "real" dollars via an upward adjustment in dollars to reflect inflation.

18 The United States Census Bureau explains the real-dollar value as follows:

19 "Constant-dollar value (also called real-dollar value) is a value  
20 expressed in dollars adjusted for purchasing power. Constant-dollar values  
21 represent an effort to remove the effects of price changes from statistical series  
22 reported in dollar terms. The result is a series as it would presumably exist if prices  
23 were the same throughout as they were in the base year-in other words, as if the  
24 dollar had constant purchasing power."<sup>1</sup>

---

<sup>1</sup> <https://www.census.gov/topics/income-poverty/income/guidance/current-vs-constant-dollars.html>

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1 **Q12. Does constant dollar averaging align with economic principles?**

2 A12. Yes. Constant dollar averaging adjusts for the impact of inflation on historical  
3 costs, providing for a more accurate forecast of future costs. That is, constant dollar  
4 averaging maintains the purchasing power of being able to purchase the same units  
5 of materials and labor over time.

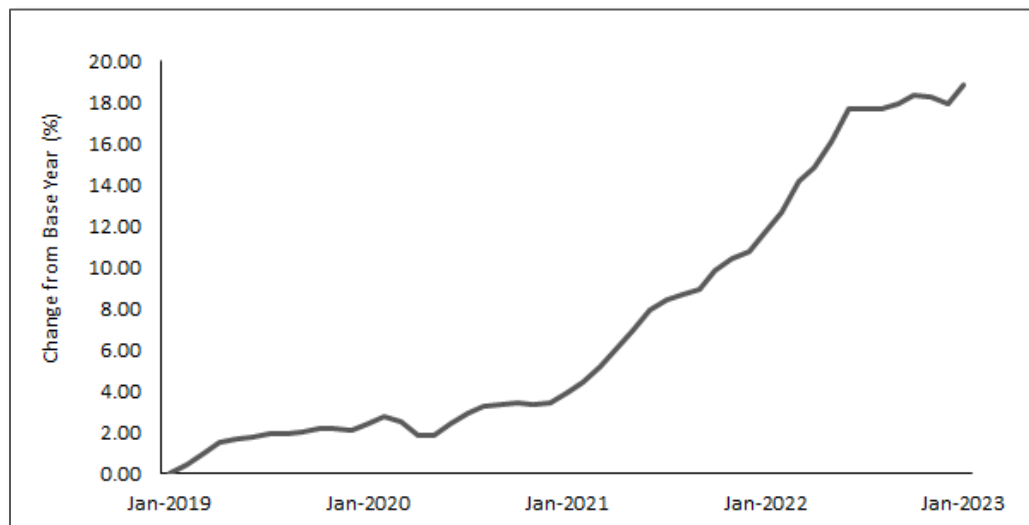
6  
7 **Q13. Do macroeconomic trends demonstrate inflation in utility materials and labor**  
8 **over time?**

9 A13. Yes. Inflation has increased substantially over the historic January 2019 through  
10 December 2022 period based on the U.S. consumer price index (“CPI”).  
11 Specifically, the CPI rose approximately 18.00 percent over the historic January  
12 2019 through December 2022 period, as shown in Figure 1 (below).

13

14

**Figure 1 Consumer Price Index for All Urban Consumers (CPI-U)**



15

Source: U.S. Bureau of Labor Statistics



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1   **Q14. What are the implications of inflation?**

2   A14. The presence of inflation demonstrates a decline in purchasing power. In other  
3       words, doing the same volume of work in 2023 as was done in 2019 would cost  
4       approximately 18.00 percent more due to inflation.

6   **Q15. Does constant dollar averaging adjust for the decline in purchasing power?**

7   A15. Yes. Constant dollar averaging adjusts for the decline in purchasing power due to  
8       inflation. Specific benefits of constant dollar averaging include:

- 9       • **Removes the impact of changes in price levels:** Prevents the  
10       understatement of future costs due to inflation, ensuring projections reflect  
11       real economic conditions.
- 12       • **Establishes a comparable baseline:** Eliminates year-over-year  
13       fluctuations caused by price level changes, making cost comparisons more  
14       accurate and reliable.
- 15       • **Minimizes the potential for budget shortfalls:** Ensures financial planning  
16       aligns with long-term economic trends and actual cost structures, reducing  
17       the risk of underfunding essential operations and infrastructure investments.

19   **IV. CONSTANT DOLLAR AVERAGING AS A RECOGNIZED PRACTICE**

20   **Q16. Is constant dollar averaging a recognized practice in cost forecasting and**  
21       **planning?**

22   A16. Yes. Developing cost forecasts based on constant dollar averaging of historical  
23       costs is a recognized practice in cost forecasting and planning. The Department of  
24       Defense (DoD) and the Government Accountability Office (GAO), for example,

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1 rely on inflation-adjusted historical costs to achieve cost forecasting integrity and  
2 fiscal accountability.

3 The DoD states, “Constant-year dollars are the appropriate units for  
4 presenting the stream of costs when comparing alternatives. Decision makers need  
5 to understand which alternative is more cost-effective after removing distortions to  
6 the purchasing power of the dollar caused by different expenditure timing.”<sup>2</sup>

7 The GAO states that “expressing an estimate in base year dollars  
8 removes the effects of inflation and enables comparing separate  
9 estimates...Normalizing the data to make them consistent is imperative to obtain  
10 good results. All cost data should be converted to a constant base year.”<sup>3</sup>

11

12 **Q17. Is constant dollar averaging a recognized practice in the utility industry?**

13 A17. Yes. Constant dollar averaging of historical costs is a recognized practice in the  
14 utility industry, as shown in Table 1 (below).

15 **Table 1 Select Jurisdictions Practicing Constant Dollar Averaging**

| Utility            | Description                                                                                                                   |
|--------------------|-------------------------------------------------------------------------------------------------------------------------------|
| SDG&E (CA)         | Applies inflation adjustment to 5-year average of historic capital additions <sup>4</sup>                                     |
| National Grid (MA) | Applies inflation adjustment to 5-year average of historic capital additions, escalating to current year dollars <sup>5</sup> |
| PECO (PA)          | Normalizes storm expenses based on the average storm expense during a 5-year period, as adjusted for inflation <sup>6</sup>   |

<sup>2</sup> U.S. Department of Defense Inflation and Escalation Best Practices for Cost Analysts, December 2021, p. 85

<sup>3</sup> GAO-20-195G, Cost Estimating and Assessment Guide, March 2020, p.74 & p.114, [Access Link](#)

<sup>4</sup> CPUC A.22-05-015, Direct Testimony of Melanie Hancock, May 2022, p.8 [Access Link](#)

<sup>5</sup> DPU 22-22, Order, November 30, 2022, [Access Link](#)

<sup>6</sup> Pennsylvania PUC, Docket No. R-2024-3046931, Direct Testimony of Michael J. Trzaska, Exhibit MJT-2, p. 78, [Access Link](#)

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| Utility                        | Description                                                                                                                           |
|--------------------------------|---------------------------------------------------------------------------------------------------------------------------------------|
| Atco Electric (Alberta)        | Applies inflation adjustment to 5-year average of historic capital additions, escalating to current year dollars <sup>7</sup>         |
| Portland General Electric (OR) | Applies inflation adjustment to 3-year historic average of non-fuel materials and supplies costs to current year dollars <sup>8</sup> |

1

2 In Oregon, for example, the Public Utilities Commission approved constant dollar  
3 averaging of non-fuel materials and supplies:

4 “We find that the use of a three-year average, adjusted for inflation, strikes  
5 the right balance between ensuring a reasonable test year balance based on the  
6 company's historic balance and capturing any trend of increases.”<sup>9</sup>

7

8 Additionally, the California Public Utilities Commission stated:

9 “Restating all accounts in constant dollars provides greater comparability  
10 among different years because all expenses appear in the same “current year  
11 average dollars,” regardless of when the expenses were incurred.”<sup>10</sup>

12

13 **V. RECENT COMMISSION DECISION**

14 **Q18. What concerns did the Commission raise in the Company’s prior rate case**  
15 **regarding constant dollar averaging?**

16 A18. The Commission’s Order in the Company’s prior rate case (Case No. U-21534)  
17 denied Distribution cost forecasts based on constant dollar averaging of historical

---

<sup>7</sup> Atco Ltd. Financial Information for the nine months ended September 30, 2023, p. 15, [Access Link](#)

<sup>8</sup> Oregon UE 435, Staff Exhibit 1500, Moore Opening Testimony, p.3, Footnote 2; Oregon Public Utility Commission, UE 435, Order, December 20, 2024, p. 24, [Access Link](#);

<sup>9</sup> Oregon Public Utility Commission, UE 435, Order, December 20, 2024, p. 24, [Access Link](#)

<sup>10</sup> CPUC Resolution T-17132 as Modified by Decision 11-05-036, Attachment 1, January 29, 2009, p. 10, [Access Link](#)

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1 costs. The Commission's primary concern was insufficient evidence that the  
2 Company's historical costs demonstrated inflation. The Commission's Order  
3 states:

4 "...its response to the use of constant dollar averaging might be different if the  
5 evidence showed that these expenditure categories are both volatile and  
6 consistently trending upwards."<sup>11</sup>

7

8 **Q19. What expenditure categories were specifically referenced in the Commission**  
9 **Order?**

10 A19. The Commission's Order referenced the following Distribution Operations  
11 expenditure categories:

- 12 • Emergent Replacements (storm, non-storm, and substation reactive)
- 13 • Connections, New Load, and Relocations
- 14 • Electric System Equipment, Normal Retirement Units Changeout (NRUC)
- 15 and Improvement Blankets
- 16 • General Plant, Tools & Equipment.<sup>12</sup>

17

18 **Q20. What evidence did the Commission rely on to support its decision?**

19 A20. The Commission's Order stated certain Distribution cost categories demonstrated  
20 variability without necessarily demonstrating a consistent upward trend in costs that  
21 would indicate inflation. The Commission's Order states:

22 "[The Company's Exhibit] shows downward trends for emergent  
23 replacements (storm) in 2020 and 2022 (2 years out of 5), and for emergent  
24 replacements (substation reactive) in 2019, 2020, and 2022 (3 years out of 5). The

---

<sup>11</sup> Michigan PSC, Case No. Case No. U-21534, Order, January 23, 2025, p. 73

<sup>12</sup> Id., p.74

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costs reflect variability but no consistent upward trend. The Commission finds that application of the inflation factors to a simple five-year average for 2023, 2024, and 2025 is appropriate, but the prior historical adjustment that the company uses in the instant case...is not.”<sup>13</sup>

The referenced costs are summarized in Table 2 (below).

**Table 2 Emergent Replacement Costs (2018-2022)**

| Program                                     | 2018    | 2019    | 2020    | 2021    | 2022    |
|---------------------------------------------|---------|---------|---------|---------|---------|
| Emergent Replacements (storm)               | 142,108 | 178,931 | 150,897 | 395,286 | 181,326 |
| Emergent Replacements (substation reactive) | 44,275  | 40,386  | 38,131  | 46,008  | 40,382  |

**Q21. What factors drive variability in the expenditures in Table 2 (above)?**

A21. A significant driver of variability in the expenditures is volume of work, as shown in Table 3 (below).

**Table 3 Customer Interruptions (2019-2022)**

|                        | 2018      | 2019      | 2020      | 2021      | 2022    |
|------------------------|-----------|-----------|-----------|-----------|---------|
| Customer Interruptions | 1,103,025 | 1,233,700 | 1,080,677 | 1,825,882 | 965,393 |
| Percentage Change      |           | 11.80     | -12.40    | 69.00     | -47.10  |

The year-over-year reductions in emergent replacements (storm) of 15.70 percent in 2020 and 54.10 percent in 2022 as shown in Table 2 can be explained by year-over-year reductions in customer restorations and interruptions of 12.40 percent in 2020 and 47.10 percent in 2022 as shown in Table 3. The tables show the weather events in 2020 and 2022 resulted in fewer customer outages and fewer customer

<sup>13</sup> Michigan PSC, Case No. Case No. U-21534, Order, January 23, 2025, pp.73-74

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1 restorations, which resulted in a reduction in volume of work and expenditures. A  
2 reduction in overall expenditures therefore should not necessarily be viewed as an  
3 indication of the absence of inflation but in these cases a reduction in volume of  
4 work. A similar relationship generally applies to the other expenditures in Table 2  
5 (above): that is, fluctuations in expenditures from one year to the next can generally  
6 be explained by changes in the cost of materials and labor as well as the volume of  
7 activity.

8

9 **Q22. Are costs inflated twice under the constant dollar averaging?**

10 A22. No, and the Commission has recognized this. On page 73 of the Order, the  
11 Commission stated:

12 “The Commission notes that no year within the 2018-2022 five-year  
13 average period nor any year in the bridge or test periods is actually inflated twice.”<sup>14</sup>

14

15 **VI. DTE ELECTRIC’S COST TRENDS RELATED TO MATERIALS AND**

16 **LABOR**

17 **Q23. Do you agree there is no upward trend in emergent replacement (storm) costs?**

18 A23. No. Decreases in emergent replacement costs in Table 2 (above) do not necessarily  
19 represent the absence of inflation. Specifically, emergent replacement (storm) costs  
20 comprise two types of costs – materials and labor – that both demonstrate an  
21 upward trend in costs.

---

<sup>14</sup> Id.

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1 **Q24. Has there been an upward trend in costs for materials commonly replaced**  
2 **during emergent replacements in recent years?**

3 A24. Yes. There has been an upward trend in costs for materials commonly replaced  
4 during emergent replacements that well exceeds the increase in CPI-U, as shown in  
5 Table 4 (below)

6 .

7 **Table 4 Cost Increases for Materials Replaced during Emergent**  
8 **Replacements<sup>15</sup>**

| Material Category       | Stock Item Description                    | 2020– 2024 % Change |
|-------------------------|-------------------------------------------|---------------------|
| Transformer-Overhead    | 50 kVA pole top transformer               | 318%                |
| Transformer-Underground | 50 kVA padmount transformer               | 468%                |
| Pole-Wood               | 45' Class 3 wood pole-Cedar               | 114%                |
| Underground Cable       | 1000 kcmil AL UG EPR<br>(Price Per Foot)  | 68%                 |
| Overhead Conductor      | 636 OH Conductor<br>(Price Per Foot)      | 40%                 |
| Overhead Crossarms      | CROSSARM_with Center Bracket              | 36%                 |
| Fuse Carriers           | CUTOUT_FUSED,OP N,POLYMER,7.2-14.4KV,110K | 47%                 |
| Insulators              | INSULATOR_ELECT, CLAMP TOP,28KV,POLYMER   | 43%                 |
| Substation              | 50MVA Power Transformer                   | 54%                 |
| Substation              | Load Tap Changer                          | 21%                 |

<sup>15</sup> see Testimony of Brian L. Hill, Table 1.

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1 The Table shows cost increases for materials commonly replaced during emergent  
2 replacements including transformers, poles, overhead conductors, insulators, fuse  
3 carriers, underground cable, and substation equipment have exceeded the rate of  
4 inflation, as measured by the CPI-U index.<sup>16</sup> For example, costs for overhead and  
5 underground transformers have increased by more than 300.00 percent and 400.00  
6 percent, respectively, since 2020.

7

8 **Q25. What are the implications of increases in material costs?**

9 A25. Increases in material costs over the past several years have reduced the Company's  
10 purchasing power, that is, the Company is unable to replace the same number of  
11 units for the same dollar amount.

12

13 **Q26. Has there been an upward trend in Distribution Operations contract labor**  
14 **rates over the past several years?**

15 A26. Yes. There has been an upward trend in distribution operations contract labor rates  
16 over the past several years based on the Company's collective bargaining  
17 agreements, as shown in Figure 2 (below). Company Witness Fix discusses DTE  
18 Electric's labor rate escalations in his direct testimony.

---

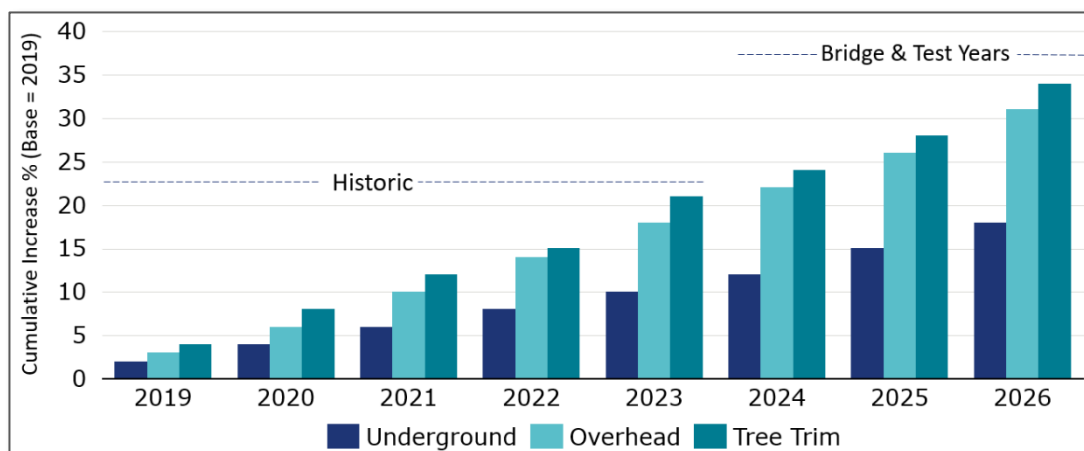
<sup>16</sup> id.



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1

**Figure 2 : Increase in Distribution Operations Contract Labor Rates<sup>17</sup>**



2

3 **Q27. What are the implications of the increases in Distribution Operations contract**  
4 **labor rates?**

5 A27. Increases in the Company's distribution operations contract labor rates over the past  
6 several years have reduced the Company's purchasing power for labor. For  
7 example, contract labor rates for overhead workers since 2019 will have increased  
8 more than thirty percent by 2026. Consequently, the same dollar amount in 2026  
9 pays for 30.00 percent fewer labor hours for overhead labor work than in 2019. It  
10 is important to note that overhead workers are a key resource during emergent  
11 events.

12 Without adjustments for inflation, cost forecasts based on  
13 unadjusted historical labor costs do not reflect a decline in purchasing power, which  
14 results in a cost forecast with fewer labor hours.

15

16 **Q28. Do the upward trends in contract labor rates support use of constant dollar**  
17 **averaging?**

<sup>17</sup> see Testimony of Brian L. Hill, Figure 1.

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1 A28. Yes. Constant dollar averaging adjusts for upward trends in contract labor rates to  
2 ensure cost projections maintain in the future the same volume of repair work  
3 during emergent events as in the past.  
4

5 **Q29. Do cost increases for materials and labor generally apply to Distribution**  
6 **Operations expenditures described above?**

7 A29. Yes. Cost increases for materials and labor generally apply to Distribution  
8 Operations expenditures described above. However, fluctuations in expenditures  
9 from one year to the next can generally be explained by changes in the cost of  
10 materials and labor, as described earlier, as well as the volume of activity.  
11

12 **VII. CONCLUSION**

13 **Q30. What are your conclusions?**

14 A30. My conclusions are summarized below:

15 • Inflation reduces the purchasing power of goods and services. Cost  
16 forecasts that assume the dollars spent in the future are the same exact  
17 dollars that were spent in the past will yield fewer goods and services that  
18 can be purchased in the future, meaning the Company cannot perform the  
19 same volume of repair work during emergent events today at the spending  
20 incurred in historical periods.

21 • The Company's cost forecast relies on historical costs that are inflation-  
22 adjusted through constant dollar averaging to reflect the cost of goods and  
23 services to be purchased in the future. Absent such inflation adjustment  
24 through constant dollar averaging, the Company will be unable to purchase  
25 in the future the same volume of goods and services as in the past.

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- 1                   • Cost forecasts based on constant dollar averaging is a recognized practice
- 2                   in cost forecasting and financial planning. The Department of Defense and
- 3                   the Government Accountability Office, for example, rely on inflation-
- 4                   adjusted historical costs to achieve cost forecasting integrity and fiscal
- 5                   accountability. In the utility industry, several jurisdictions have recognized
- 6                   the necessity of constant dollar averaging, including California, Oregon,
- 7                   and Massachusetts.

8

9   **Q31. Does this conclude your direct testimony?**

10   A31. 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-21860

## QUALIFICATIONS

AND

## DIRECT TESTIMONY

OF

BILL CHIU

**DTE ELECTRIC COMPANY**  
**QUALIFICATIONS AND DIRECT TESTIMONY OF BILL CHIU**

Line  
No.

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

2   A1.   My name is Bill Chiu. My business address is One Energy Plaza, Detroit, Michigan  
3       48226. I am employed by DTE Electric (“DTE Electric” or the “Company”).

4

5   **Q2.   On whose behalf are you testifying?**

6   A2.   I am testifying on behalf of DTE Electric.

7

8   **Q3.   What is your educational and professional background?**

9   A3.   I received a Bachelor of Science degree in electrical engineering with emphasis in  
10       Power System Engineering from California Polytechnic State University. I earned  
11       a Master of Science in electrical engineering and a Master of Business  
12       Administration from the University of Southern California. I am also a registered  
13       professional engineer in the state of California.

14

15       I joined DTE Electric in 2024 as Vice President of Distribution Engineering and  
16       Technology with responsibility for central engineering, operational technology and  
17       asset strategy for the distribution grid at DTE Electric. Prior to joining DTE  
18       Electric, I served as the Vice President of Operations for Puerto Rico-based Luma  
19       Energy from 2022 to 2024, where I was responsible for the operation, maintenance,  
20       and capital improvements of the bulk power grid for the islands of Puerto Rico.  
21       Prior to my role at Luma Energy, I held several executive leadership roles at  
22       Southern California Edison (“SCE”), including managing director of major capital  
23       expansion programs for the bulk power grid, managing director of the Grid  
24       Modernization and Resiliency Program Management Office, and several other  
25       leadership roles across engineering, operations, and business strategy related to the

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transmission and distribution power grid from 1998 to 2022. Prior to SCE, I held technical leadership and engineering roles from 1989 to 1998 in the development of distribution design/construction standards, major UHV transmission projects with deployment of Flexible AC Transmission System (FACTS) technology such as SVCs, and Series Caps for line compensations, HVDC converters, and distribution system engineering.

**Q4. What are your current job responsibilities?**

A4. As Vice President of Distribution Engineering and Technology for DTE Electric, I lead the Company's strategy to improve electric system reliability and to modernize the power grid to accommodate greater levels of distributed energy resources. This includes overseeing the Company's Distribution Operations ("DO") engineering, grid modernization and reliability strategy, deploying technology applications, as well as driving improvements in asset management and work management practices.

**Overview and Executive Summary**

**Q5. Please summarize your testimony.**

A5. My testimony outlines the strategic investments the Company is making in the electric distribution grid to improve reliability. The Company operates one of the oldest electric grids in the country, and that system is showing its age. Much of the grid is composed of aged lines and equipment that create capacity constraints, pose safety and operational challenges, and impede efficient restoration during outages. The Company is taking concrete action to modernize the grid, but maintaining safe and reliable operation in the future will require more than the current level of

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1 investments or routine maintenance. The investment plans detailed in this case  
2 provide a roadmap and framework for accomplishing our commitment to  
3 customers, including our goal to reduce power outages by 30% and cut outage time  
4 in half by 2029. We know from our recent reliability performance that when we  
5 invest, it works.  
6  
7 The Company's strategic investments in the electric distribution grid align with  
8 direction from the Commission. Specifically, the Company's proposed  
9 investments in the distribution grid meet the objectives set forth by the Commission  
10 in the Service Quality and Reliability Standards ("SQRS") proceeding, and in the  
11 February 27, 2025 Order in the Financial Incentives and Disincentives docket (Case  
12 No. U-21400). They also advance recommendations in the DTE Electric Utility  
13 Distribution Audit Report ("Audit" or "Audit Report")<sup>1</sup>, conducted by Liberty  
14 Consulting Group and filed in Case No. U-21305, which finds that the Company's  
15 2023 Distribution Grid Plan (DGP)<sup>2</sup>, if fully executed, would improve reliability  
16 for customers over the next five years. In short, the Audit reaffirmed the need for  
17 reliability improvements and largely supports the Company's strategy for how to  
18 improve distribution operations and power delivery service for customers. Most  
19 importantly, the Company's emphasis on reliability improvements and plans to  
20 improve the grid are responsive to our customers and other stakeholders, for whom  
21 safety, reliability, and resiliency issues are chief priorities.

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<sup>1</sup> Though the title indicates DTE Energy Company (DTE Energy), the audit findings apply to DTE Electric, a wholly owned subsidiary of DTE Energy. The DTE Electric Audit Reports are available in filing ## U-21305-0012 and U-21305-0013 at <https://mi-psc.my.site.com/s/case/5008y000005KkdgAAC/in-the-matter-on-the-commissions-ownmotion-to-investigate-audit-and-review-the-methods-employed-by-dte-electric-company-and-consumers-energycompany-to-secure-good-electric-service-and-the-safety-of-the-public-pursuant-to-mcl-460555-and-mcl-460556> (accessed February 15, 2025)

<sup>2</sup> Case No. U-21860, Exhibit A-23, Schedule M8

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1 The electric grid faces a variety of challenges related to capacity, resiliency, and  
2 new technology that change the way electricity is generated, delivered, and used.  
3 This context in which the Company is operating helps to inform and drive the need  
4 for the projects and expenditures presented in this case. First, increasing storm  
5 activity and extreme weather events pose a growing threat to an already-aged fleet.  
6 Second, electrification trends related to the shift from fossil-based energy sources  
7 will have implications for the capacity of the existing distribution system. Finally,  
8 the Company must adapt to accommodate the proliferation of new distributed  
9 generation and distributed storage resources, which introduce certain distribution  
10 grid-specific complications.

11

12 In line with our plan for significant and sustained investment in the distribution  
13 system, the Company invested \$1.6 billion for the historical 12-month period  
14 ending December 31, 2023 and is requesting \$3.2 billion of capital investments for  
15 the 24-month period ending December 31, 2025, and \$1.9 billion of capital  
16 investments for the 12-month projected test year ending December 31, 2026. These  
17 capital investments are driven principally by four essential pillars that work  
18 together to form a holistic strategy across the more near-term improvements while  
19 the Company embarks on the more extensive rebuilds for portions of the grid. First,  
20 the Company continues its emphasis on the Tree Trimming pillar, which will see  
21 the end of the Tree Trim Surge in 2025 followed by implementation of a risk-based  
22 cycles approach to vegetation management.<sup>3</sup> Second, the Company will pursue

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<sup>3</sup> Tree trimming is not included the strategic capital, except where specifically required to support a capital project.



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1 programs in the Infrastructure Resilience and Hardening pillar. Specifically, it will  
2 enhance the Pole-Top Maintenance and Modernization Program (“PTMM”) and  
3 complete the 4.8 kV Hardening Program in Detroit by 2027 to replace failing poles  
4 and equipment. Third, the Company’s Infrastructure Redesign and Modernization  
5 pillar focuses on converting the aged and overloaded 4.8 kV ungrounded system to  
6 a modern 13.2 kV grounded system, and rebuilding and relocating portions of the  
7 subtransmission system. These efforts are designed to enhance safety and  
8 reliability, and address capacity constraints. Finally, the Company plans to invest  
9 in the Technology and Automation pillar, with specific investment in smart grid  
10 technology, including recloser installation. Other investments in this pillar will  
11 support grid management, planning, and operations to most efficiently and reliably  
12 deliver power to the Company’s customers.

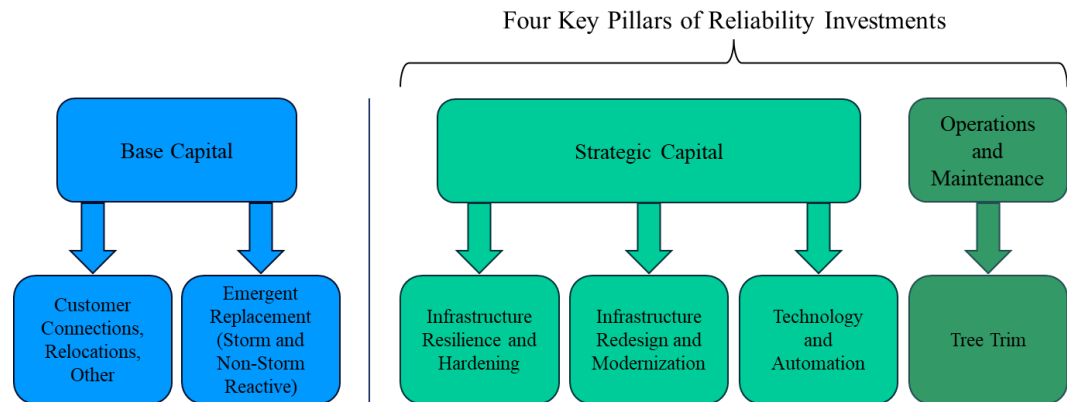
13

14 Beyond these four key pillars of reliability focused investments, there is Base  
15 Capital that supports the necessary and critical set of investments that are  
16 responsive to emergent or specific customer needs including Customer  
17 Connections, Relocations, Others, and the Emergent Replacements for Storm, Non-  
18 Storm, and Substation Reactive programs. The overall approach is summarized  
19 pictorially below with base capital shown in blue and planned strategic capital (and  
20 Tree Trim O&M) investment shown in green.

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**Figure 1 DO Capital Investments and O&M Expenses**



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I also discuss the Company's capital variance for distribution operations. Overall, the Company deployed \$1.5 billion of capital in 2024, as compared to the \$1.4 billion authorized in Case No. U-21534, which demonstrates that the Company's projections of system needs and expenditures are on target, reasonable, and prudent. Throughout the past year, the Company was able to address emerging needs such as storm restorations, support changing timelines for new customer line extensions and developments, adjust to agency permitting delays, as well as address seasonal loading contingencies that impact outage windows for capital work. Taken together, however, the capital variance is modest and closely aligns to the Company's demonstrated financial needs.

**Q6. What is the purpose of your testimony?**

A6. The purpose of my testimony is to provide an overview of the state of the Company's distribution power grid that serves a population of approximately five million people across the 2.3 million residential, commercial, and industrial customers in the 7,600 square miles of DTE Electric's service area. I will also

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1 discuss the Company's distribution operations and related expenditures, as well as  
2 introduce the witnesses who will explain in greater detail these concepts and  
3 support DTE Electric's planned distribution grid investments that are needed to  
4 continue to safely and reliably serve our customers, to harden the power grid against  
5 the inclement weather conditions of greater frequency and intensity, and to address  
6 the increasing reliance on electricity while facilitating the transition to a future with  
7 more diverse distributed energy resources (DERs). At a high level, my testimony  
8 will:

9 (i) Discuss the state of the electric grid and DTE Electric's improving  
10 reliability performance;

11 (ii) Outline the challenges and opportunities brought about by the changing  
12 external factors impacting the performance of the grid;

13 (iii) Address the Company's analysis of the Audit Report from Liberty  
14 Consulting, including adjustments to prior investment plans that the  
15 Company is proposing as a result of the Audit's findings, as well as  
16 areas where the Company believes a different course of action is  
17 appropriate;

18 (iv) Provide an overview of the Company's proposed four pillars of strategic  
19 capital investments;

20 (v) Introduce the analytics of the Company's Global Prioritization Model  
21 ("GPM") and Reliability Model, which drive and support the  
22 Company's DO planning, investment decisions and priorities in this  
23 proceeding; and in response to Commission feedback in Case No. U-  
24 21534 and other proceedings, discuss DTE Electric's approach to  
25 benefit-cost analysis, including an outline of our plan to enhance and

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1 bolster this element of investment planning, both in this case and in  
2 future cases;

3 (vi) Discuss the DO portion of the Company's capital variance for the  
4 historical year of 2023 and bridge years 2024 and 2025, and

5 (vii) Describe the Company's proactive measures to improve municipal  
6 project coordination.

7

8 **Q7. How is your testimony organized?**

9 A7. My testimony consists of seven parts:

10 Part I State of the Grid and Need for Sustained Investment

11 Part II The Changing Grid

12 Part III Audit Report and DTE Electric Response

13 Part IV Strategic Capital Overview

14 Part V GPM / Reliability Models and Benefit-Cost Analysis

15 Part VI Capital Variance – Distribution Operations

16 Part VII Municipal Project Coordination

17

18 **Q8. Are you sponsoring any exhibits in this proceeding?**

19 A8. Yes. I am supporting the following exhibits:

| 20 | <u>Exhibit</u> | <u>Schedule</u> | <u>Description</u>                                 |
|----|----------------|-----------------|----------------------------------------------------|
| 21 | A-23           | M1              | U-21534 2023 Forecast vs. U-21860 Comparison       |
| 22 | A-23           | M2              | U-21534 2024 Forecast vs. U-21860 Comparison       |
| 23 | A-23           | M3              | U-21534 2025 Forecast vs. U-21860 Comparison       |
| 24 | A-23           | M8              | 2023 Distribution Grid Plan, MPSC Case No. U-20147 |

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1 **Q9. Were these exhibits prepared by you, under your direction, or otherwise**  
2 **developed by the organization you lead?**

3 A9. Yes.

4

5 **Q10. Are there other witnesses providing testimony on distribution operations**  
6 **issues in this proceeding?**

7 A10. Distribution Operations capital and O&M expenditures, as well as other related  
8 activities, are supported by seven DO witnesses in this case. Together, these  
9 witnesses discuss the reasonableness and prudence of DO capital and O&M  
10 expenditures, exhibit content, Tree Trim, Environmental Justice (“EJ”), and other  
11 topics related to DO. A high-level summary of these seven witnesses’ scope of  
12 testimony is introduced in Table 1 below.

13

14

**Table 1 DO Witnesses Introduction<sup>4</sup>**

| <b>Witness</b> | <b>Scope of Testimony</b>                                                                                                                                                                                                         |
|----------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Kryscynski     | Distribution O&M and related exhibits, the Company’s Global Prioritization and Reliability Models, and approach to Environmental Justice in investment planning.                                                                  |
| Hill           | Base Capital programs, Emergent Replacements and Customer Connections, Relocations & Other.                                                                                                                                       |
| Steudle        | Tree Trimming Surge Program, O&M expenses for past and projected periods, and explanation of the program’s future post-Surge.                                                                                                     |
| Robinson       | Strategic capital pillar of Infrastructure Resilience and Hardening.                                                                                                                                                              |
| Stowe          | Strategic capital pillar of Infrastructure Redesign and Modernization.                                                                                                                                                            |
| Rademacher     | Strategic capital pillar of Technology & Automation                                                                                                                                                                               |
| De Stigter     | Benefit-cost analysis for four distribution investment programs<br>1) Pole and Pole Top Maintenance & Modernization,<br>2) Strategic Undergrounding,<br>3) Distribution Automation, and<br>4) Grid Automation Telecommunications. |

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<sup>4</sup> See additional details described by Witness Leslie in her testimony.

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1 **PART I: State of the Grid and Need for Sustained Investment**

2 **Q11. What is the state of the electric grid in the Company's service territory**  
3 **today?**

4 A11. Michigan – and the City of Detroit, in particular – has one of the oldest electric  
5 grids in the country, and that system is showing its age. Approximately 19,000  
6 miles, or 45% of the Company's approximately 42,000 miles of distribution  
7 infrastructure, is composed of aged 4.8 kV lines that were primarily constructed  
8 between 1930 and 1965 and pose significant operational and safety challenges.  
9 These operational and/or safety challenges are due to capacity constraints,  
10 incompatibility with surrounding 13.2 kV infrastructure, back lot access  
11 constraints, as well as longer outage restoration times when outages occur due to  
12 having obsolete equipment where replacement parts are no longer available.

13  
14 While the Company has begun conversion efforts based on the need to address  
15 capacity constraints, only about 220 miles of those lines (about 1%+) have been  
16 converted to the more modern 13.2 kV system to date. There is much more work  
17 to be done. Even as the Company has worked to integrate newer, safer, and more  
18 reliable technologies, those updates have struggled to keep pace with the vast aging  
19 and deteriorating legacy system. Dated lines, poles, and hardware are only getting  
20 older, and with that age comes increased risk for reliability issues. While the  
21 Company's investments to date have improved grid safety, reliability, resilience,  
22 and operability, modernizing the system in line with current industry standards and  
23 maintaining safe operation in the future will require significant and sustained  
24 investment.

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1     **Q12. What are the recent reliability metric trends for the Company’s system?**

2     A12. There are two metrics that are most commonly used to measure the reliability  
3         performance of the distribution grid in terms of the frequency and duration of the  
4         outages – namely the System Average Interruption Frequency Index (“SAIFI”) and  
5         the System Average Interruption Duration Index (“SAIDI”). These metrics also  
6         have two different variations that are commonly referred to as “all-weather” to  
7         account for all outages regardless of the severity of the weather conditions and “Ex-  
8         MED,” which excludes major event days.<sup>5</sup> There is a third commonly used metric,  
9         the Customer Average Interruption Duration Index (“CAIDI”), which is defined as  
10        the mathematical relationship of SAIDI divided by SAIFI. DTE Electric’s all-  
11        weather performance in 2024 was in the 3<sup>rd</sup> quartile for the outage duration (SAIDI)  
12        and in the 2<sup>nd</sup> quartile for outage frequency (SAIFI).<sup>6</sup> A combination of the  
13        reliability capital improvements in the grid and less extreme weather resulted in a  
14        nearly 70% decrease in outage duration times between 2023 and 2024. Looking  
15        back further in recent history, electric outages decreased by 14% and the amount of  
16        time customers were without power decreased by 38% in 2024 compared to the  
17        five-year average (2019 to 2023). This is further validation that when the Company  
18        makes these investments, as we have been in recent years, reliability improvements  
19        become a reality as described by the respective witnesses for these reliability  
20        investment pillars. While these are marked improvements in the service reliability  
21        that our customers are experiencing due to investment in the system to date, the  
22        Company anticipates ongoing challenges as a large portion of the grid assets are  
23        expected to have increasing failure rates as the equipment approaches the wearout

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<sup>5</sup> See IEEE 1366, IEEE Guide for Electric Power Distribution Reliability Indices for further discussion on the various reliability performance indices and the method for the exclusion of major event days.

<sup>6</sup> The quartile performance is benchmarked with the latest available data from IEEE as of February of 2025.

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1 phase of the “bathtub curve”<sup>7</sup> with the grid continuing to grow older each year.  
2 This is an important consideration, and the success of previous investment  
3 demonstrates the need to be proactive in investments that will harden and  
4 modernize the grid in supporting continued improvements in safety, reliability, and  
5 resiliency.

6

7 **Q13. Given the state of the electric grid in DTE Electric’s service area, how does**  
8 **DTE Electric plan to improve electric service reliability?**

9 A13. All electric distribution systems require routine maintenance, systematic upgrades,  
10 and regular replacement of assets that are constantly aging and deteriorating. Just  
11 maintaining reliability requires considerable work. For example, assuming a power  
12 grid with 10,000 circuit breakers with an average of a 50-year lifespan, more than  
13 200 of those breakers will need to be replaced each year just to maintain status quo.  
14 DTE Electric’s system, in its current state, requires more than maintenance-level  
15 investment. Modest contributions or short-term injections of capital will not  
16 advance the system beyond the status quo. To meaningfully improve the system  
17 from its current state, it will require a significant and sustained level of investment  
18 over many years. The Company’s customers and other stakeholders have been  
19 clear; virtually every intervenor in recent cases has advocated for increased  
20 reliability. The reality, however, is that improved reliability must come through  
21 consistent, and prioritized investment in the system. Greater reliability is only  
22 possible with increased investment in DTE Electric’s distribution grid  
23 infrastructure for the benefit of our customers. This is the basis for the Company’s

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7 See additional explanation by the National Institute of Standards and Technology (NIST) on the concept of the “bathtub” curve (<https://www.itl.nist.gov/div898/handbook/apr/section1/apr124.htm>), accessed April 8, 2025.



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1 2023 Distribution Grid Plan, which describes the path forward to both improve  
2 near-term reliability and provide a roadmap for the required investment necessary  
3 to improve and maintain long-term reliability. That theme was also echoed in the  
4 Audit Report issued last year.

5  
6 Today, DTE Electric's system is at a critical juncture; the Company has  
7 opportunities to invest proactively, focusing strategically on areas for maximum  
8 improvement and impact. If meaningful upgrade efforts are delayed, substantial  
9 investment will still be required, only it will be driven by operational failures rather  
10 than optimized and prudent planning. A reactive approach results in higher costs  
11 for customers due to the emergency nature of the reactive work. Reactive spending  
12 rather than planned strategic investment will only grow the longer these proactive  
13 investments are delayed (not to mention the negative reliability impacts to the  
14 Company's customers) as will the aggregate cost associated with addressing the  
15 underlying issues.

16

17 **Q14. Does the Audit address the state of the DTE Electric grid and the need for**  
18 **distribution and subtransmission system improvement?**

19 A14. Yes. The Audit goes into detail regarding the needs of the aging DTE Electric  
20 distribution system<sup>8</sup>.

21

22 The Audit acknowledges the drawbacks of the Company's 4.8 kV system, noting  
23 that it imposes limits on capacity and requires more time to locate faults and to  
24 restore than the 13.2 kV systems<sup>9</sup>. Likewise, nearly 40% of DTE Electric's 4.8 kV

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<sup>8</sup> Case No. U-21305, Audit, Part One, pg. 10

<sup>9</sup> Case No. U-21305, Audit, Part One, pg. 2

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1 substation transformers have installation dates before 1960, with some dating back  
2 as far as 1924<sup>10</sup>, making portions of the Company’s substation assets more than 100  
3 years old – much older than that of similarly situated utilities. The Audit states that  
4 the Company’s circuit breakers are also more aged than those of other similarly  
5 situated utilities, with approximately 40% of them installed between 1930 and  
6 1960<sup>11</sup>. Much of the 4.8 kV system was also constructed using small diameter,  
7 weaker copper conductor, which is more easily broken by trees, wind, and ice than  
8 modern larger diameter aluminum conductor steel reinforced (“ACSR”) primary  
9 conductor, which has been the standard for conductors installed since the 1960s.

10

11 As an additional challenge, the Audit also notes that approximately 52% of the  
12 Company’s overhead primary circuits are located in backlots, including brush-filled  
13 alleys, making it more expensive to maintain and to trim trees due to difficulty with  
14 using standard equipment.<sup>12</sup> In addition to this access challenge, 90% of the  
15 Company’s secondary circuits use legacy open wires, as compared to modern  
16 multiplex cable. The Audit explains that this is associated with longer wait times  
17 required for repairing open wire when damaged<sup>13</sup>.

18

19

## **PART II: The Changing Grid**

20 **Q15. In addition to the age and condition-related issues you describe in Part I,**  
21 **what are the primary challenges facing the distribution grid today?**

22 A15. The electric grid faces a variety of challenges related to capacity, resiliency, and  
23 new technologies that change the way electricity is generated, delivered, and used.

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10 Case No. U-21305, Audit, Part One, pgs. 2, 24

11 Case No. U-21305, Audit, Part One, pgs. 2, 24

12 Case No. U-21305, Audit, Part One, pgs. 2, 15, 24

13 Case No. U-21305, Audit, Part One, pgs. 2, 16, 24

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1 Aside from the aging distribution system described above, there are three additional  
2 emerging external factors on the horizon that are driving the Company's investment  
3 priorities in this case. First, increasing storm activity and extreme weather events  
4 pose a growing threat to an already-aged fleet of equipment and introduces more  
5 opportunity for failure. Second, the State of Michigan's clean energy goals as  
6 outlined in the MI Healthy Climate Plan<sup>14</sup> and the associated electrification trends  
7 related to the shift from fossil-based fuel sources such as the growing electric  
8 vehicle market, as well as increasing use of electric appliances, electronics, and  
9 computing devices will have noteworthy cumulative implications for the capacity  
10 of the existing distribution system. Finally, the Company must adapt quickly to  
11 accommodate the proliferation of new Distributed Generation ("DG") and  
12 Distributed Storage ("DS") resources, which introduce certain distribution-grid  
13 specific complications. Meeting these challenges, which were first identified and  
14 described in the Company's 2023 DGP, will require thoughtful planning and  
15 meaningful investment in the coming years.

16

17 **Q16. Can you describe the challenges posed by the increases in severe storms and**  
18 **extreme weather?**

19 A16. Like many areas of the country, Michigan is experiencing storms and extreme  
20 weather events with increasing frequency and intensity. Figure 2 shows the recent  
21 trend of the Climate Extreme Index for the Upper Midwest region<sup>15</sup>.

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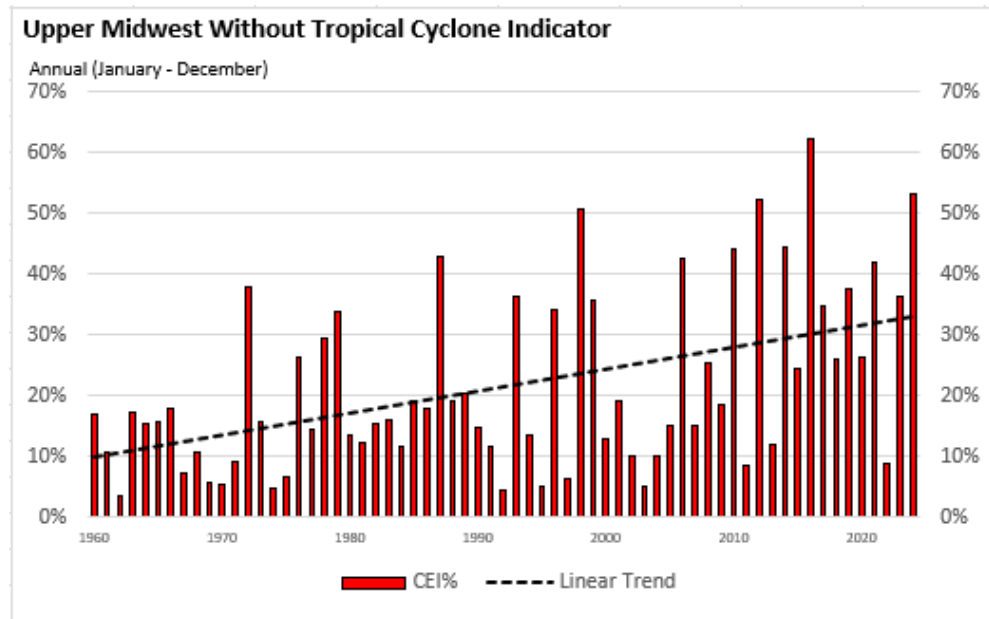
<sup>14</sup> MI Healthy Climate Plan, <https://www.michigan.gov/egle/about/organization/climate-and-energy/mi-healthy-climate-plan>, accessed April 10, 2025

<sup>15</sup> Source: U.S. Climate Extremes Index (CEI) | Graph | National Centers for Environmental Information (NCEI). CEI is the average of extreme conditions in temperature, drought, moisture surplus, precipitation, tropical storms and hurricane wind. Upper Midwest covers MI, WI, MN and IA

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**Figure 2 Climate Extreme Index for Upper Midwest Region**



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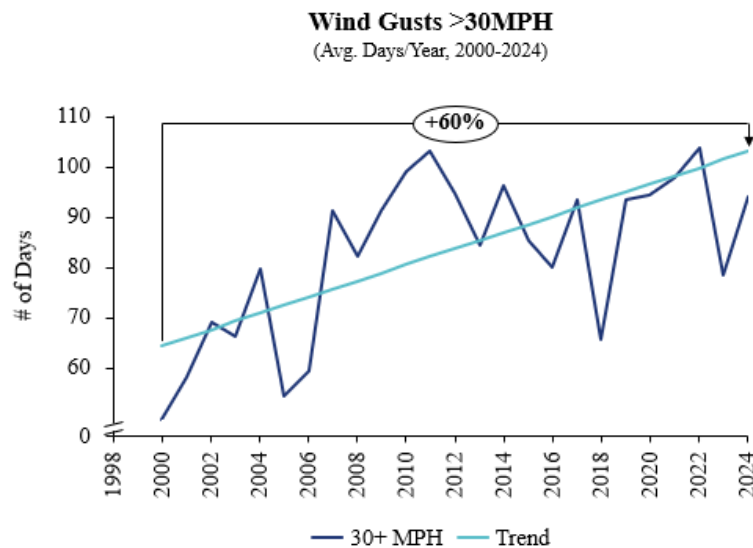
10

The Climate Extreme Index from NOAA's National Centers for Environmental Information is a compilation of key weather parameters, including extreme temperatures (both maximum and minimum), above average precipitation and its frequency, landfalling tropical storms, and hurricane wind velocities. The data clearly shows that the Company is experiencing an increasing trend of extreme weather in our service area. The evolving climate change has brought about more frequent occurrence of intense storms to the DTE Electric service area. Figure 3 shows the trend in the recorded wind speed exceeding 30 mph in our service area.

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1

**Figure 3 Michigan Wind Gusts 2000-2024**



2

3 Moreover, we are also seeing grid impacts from the microbursts<sup>16</sup> in thunderstorms  
 4 that are not uniquely tracked in the broader Climate Extreme Index. A recent  
 5 example of the microburst condition the Company experienced took place in the  
 6 early summer of 2024 where severe thunderstorms caused microbursts to develop  
 7 and led to extensive damage to our system. During that same period of time,  
 8 Southeast Michigan was also experiencing one of the longest heatwaves in 20 years.  
 9 Coupled with the extreme heat, these microbursts created a localized condition on  
 10 June 19 with wind speed exceeding 60 mph, brought down large trees and caused  
 11 extensive damage in communities including Southfield, Berkley, Beverly Hills, and  
 12 Farmington Hills. These microbursts caused some of the most significant damage  
 13 DTE Electric has ever seen in terms of damaged equipment per customer. Pictures

<sup>16</sup> A microburst is a localized column of sinking air within a thunderstorm and is usually less than or equal to 2.5 miles in diameter. Wind speeds in microbursts can reach up to 100 mph, or even higher, which is equivalent to an EF-1 tornado. See [https://www.weather.gov/bmx/outreach\\_microbursts](https://www.weather.gov/bmx/outreach_microbursts) for additional details, Accessed March 17, 2025

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1 1-4 below provide illustrative examples of the damage to the Company's overhead  
2 powerlines from the June 19 microburst.

3  
4 **Picture 1-4 – Examples of Damage from Extreme Weather Events**



5  
6 Even with this extensive damage, the Company restored roughly 93% of the  
7 impacted customers within 48 hours and within approximately three days restored  
8 more than 125,000 customers and replaced 375 poles, 550 cross-arms, 33,000 feet  
9 of conductor, and 350 transformers. This is a vivid example of the fundamental  
10 changes in the environment that the grid infrastructure from the prior century was  
11 simply not designed for, yet must be able to withstand going forward. This weather  
12 related damage is why the Company plans to accelerate the system hardening and  
13 modernization of the grid that serves the approximately five million people and all

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1 the businesses and industries that are the growth engine of the economy in our  
2 region.

3

4 The Audit noted the risks posed by increasingly damaging severe weather<sup>17</sup>, and  
5 the Company is making appropriate adjustments such as making the necessary ramp  
6 up on the much-needed PTMM program, as described by Company Witness  
7 Robinson in his testimony, to address this burgeoning threat. The Company is also  
8 taking strategic, proactive measures to minimize the impact of power outages on  
9 customers and quickly restore power following severe weather events. These  
10 efforts include attention to maintenance and inspection of all infrastructure to  
11 identify system issues or weaknesses, continued tree-trimming emphasis to  
12 minimize storm-related outages, maintaining critical equipment inventory to  
13 facilitate quick repairs of storm damage, coordination with other utilities to share  
14 resources and bolster the restoration workforce, and enhanced customer  
15 communication before, during, and after storms. Company Witnesses Hill and  
16 Ambrose address these efforts in more detail in their direct testimonies.

17

18 **Q17. How does increasing electrification affect the Company's investment**  
19 **planning for the distribution grid?**

20 A17. Changes in electricity usage are expected to increase circuit and system loading on  
21 parts of the grid. The Company is seeing an increase in electrification for cooking,  
22 space heating and cooling, and general appliances. The Veridian at County Farm  
23 community is a recent example in Ann Arbor of a 100% all-electric housing  
24 development.<sup>18</sup> Electrification of transportation, particularly the increase of

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<sup>17</sup> Case No. U-21305, Audit, Part Two, pg. 25

<sup>18</sup> Veridian at County Farm, available at <https://www.veridian.community/about>, accessed April 3, 2025

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1 residential electric vehicle adoption and partial electrification of vehicle fleets, will  
2 increase the electric system load. Currently, there are nearly 60,000 electric  
3 vehicles registered in Southeast Michigan. The Company projects this number will  
4 rise to approximately 334,000, including medium and heavy-duty vehicles by 2029.  
5 Company Witness Leuker addresses this forecast in more detail in his direct  
6 testimony. Likewise, increasing development and use of energy intensive  
7 technologies and the proliferation of connected smart devices will also contribute  
8 to increased electric loads. These additional loads will exacerbate current capacity  
9 limitations on the distribution system, requiring investments to initially address  
10 equipment overloads at the grid edge and eventually mitigate impacts on upstream  
11 equipment, including substations. In a number of areas, these marginal increases  
12 in load take away the designed contingency capability of the distribution circuits,  
13 thus reducing the ability for an adjacent circuit to pick up neighboring load during  
14 certain outage conditions, impacting reliability and response time to restore  
15 outages. These changes accelerate the need to increase the load serving capacity of  
16 the system. Witness Stowe expands on these points regarding the capacity driven  
17 conversions of the Company's older 4.8 kV system in his testimony on the  
18 Infrastructure Redesign and Modernization section.

19

20 **Q18. How does the increasing adoption of DG and DS technologies impact the**  
21 **distribution grid?**

22 A18. As new renewable energy generation technologies and behind-the-meter distributed  
23 energy resources become more popular and prevalent at a customer level, they will  
24 have an impact on the grid. In part, this is because the electric grid was not  
25 originally designed to accommodate these types of technology. Historically, the



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1 grid was designed to take electricity generated at a central generating facility and  
2 transport it – in one direction – to homes, businesses, and other end users. DG and  
3 DS technologies operate differently. Users both receive and transmit generated or  
4 stored electricity at the grid edge, which requires the grid to accommodate the bi-  
5 directional flow of electricity. Not only must the grid handle this new electricity  
6 flow pattern, but it must build in new levels of monitoring and controls to ensure  
7 the safety and reliability of a substantially more complex grid infrastructure with  
8 new load dynamics and increased coordination of operations. Modernizing the grid  
9 to enable this new era of electric generation and distribution requires technological  
10 upgrades and automation. The Company's proposals in this case advance these  
11 efforts. Witness Rademacher expands on this topic in his testimony regarding the  
12 need for additional investment in Technology and Automation.

13

14 **PART III: Audit Report and DTE Response**

15 **Q19. What are the key findings of the Audit?**

16 A19. The Audit<sup>19</sup> included a physical audit of the Company's electric infrastructure as  
17 well as a review of its programs and processes. Overall, the Audit mentioned that  
18 the Company's proposed investment plan will likely deliver the improvement in  
19 reliability that our customers demand and deserve<sup>20</sup> as well as recognizing the talent  
20 and experience of the DTE Electric team.<sup>21</sup> In the final report, the audit included  
21 the following observations:

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<sup>19</sup> On October 5, 2022, the Commission issued an order for a third-party audit of the electric distribution systems of DTE Electric Company, pursuant to MCL 460.555 and 460.556, in case number U-21305."

<sup>20</sup> Case No. U-21305, Audit, Part Two, pg. 58

<sup>21</sup> Case No. U-21305, Audit, Part Two, pg. 4.

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1                   *“We found DTE’s modeling used for evaluating, comparing, and*  
2                   *prioritizing reliability initiatives, sound. DTE’s Global Prioritization*  
3                   *model, which systematically compares and evaluates competing system*  
4                   *improvement and reliability-enhancing projects and programs across 10*  
5                   *important improvement dimensions, seems a balanced and logical*  
6                   *application of the “best fit, most reasonable cost” economic approach to*  
7                   *investment optimization. Its application at DTE is consistent with other*  
8                   *utility strategic investment good practices that Liberty has experienced.*<sup>22</sup>

9  
10           There were also 42 recommendations included in the Audit across the following  
11           three categories:

- 12                   • Safety: recommendations with the potential to improve the safety of the  
13                   distribution system in the near term;
- 14                   • Adherence to Work Standards: recommendations related to whether certain  
15                   components of the distribution system are in adherence to the Company’s  
16                   internal work standards; and
- 17                   • Distribution Plan: that recommendations that Commission Staff found  
18                   should be addressed by DTE Electric in its next distribution investment and  
19                   maintenance plan filing.

20  
21           On November 15, 2024, the Company filed its Implementation Plan, and on January  
22           17, 2025, the Company filed its Reply Comments on the Audit report in MPSC  
23           Case No. U-21305.

24  
25           In short, while the Audit identifies several key areas for improvement in the  
26           Company’s distribution operations, most of which the Company agrees with, it

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<sup>22</sup> Case No. U-21305, Audit, Part Two, pages 24- 25.

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1 fundamentally underscores the reality that there is a need to bolster the Company's  
2 reliability investments and continue to improve distribution operations and power  
3 delivery service for our customers.

4

5 **Q20. Are there any components of the Audit you would like to highlight in this**  
6 **case?**

7 A20. As mentioned earlier, the Company has filed comments in Case No. U-21305 that  
8 comprehensively addressed each of the Audit's recommendations; however, I  
9 would like to briefly address several recommendations with which the Company  
10 agrees, and that are driving the proposed investments in this case.

11

12 First and foremost, as stated previously, safety for the Company's employees and  
13 the public is the Company's paramount priority. The Audit included  
14 recommendations on the approach to the initial response to secure wire down  
15 scenes<sup>23</sup>. This is an important focus area for the Company and changes have been  
16 made to incorporate these recommendations, as further described by Witness Hill.  
17 Moreover, the Company is also expanding its effort with respect to mitigation  
18 measures to address the potential safety risks associated with wire downs.  
19 Recognizing the longer time frame it takes to rebuild the 4.8 kV system that account  
20 for the majority of the wire downs, the Company is proposing to include more near-  
21 term actions that aim to expand the current mitigation approach from reactive  
22 response to include additional efforts on prevention, such as small wire replacement  
23 and the use of infrared thermography to identify hot spots as a leading indicator for

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<sup>23</sup> Case No. U-21305, Audit. Part Two, pg. 126.

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1 potential conductor failure. Witness Robinson discusses these efforts in his  
2 testimony.

3

4 The Audit recognizes the importance of the Company's PTMM program, but notes  
5 that it needs to be augmented with pole-top visual inspections on shorter cycles.  
6 Specifically, it recommends a four-to-five year visual overhead circuit inspection  
7 program, focusing on securing visual control of the system.<sup>24</sup> Commission Staff  
8 supports this audit recommendation as "cost-effective," "beneficial," and  
9 "proactive."<sup>25</sup> The costs included in this case reflect the reality that, in the short-  
10 term, this inspection work will increase both O&M and capital costs as the  
11 Company identifies more opportunities to correct identified deficiencies and  
12 replace equipment. The tradeoff is that in the longer term, the frequency and cost  
13 of storm and trouble events is expected to decrease as more and more of the system  
14 is being hardened and modernized. See Witness Kryscynski testimony for  
15 discussion on emergent cost reductions from O&M activities and capital  
16 investments. Company Witness Robinson addresses the Company's proposal on  
17 PTMM in more detail.

18

19 Similarly, the Company appreciates and supports the Audit's endorsement of DTE  
20 Electric's ongoing tree trimming activities; in fact, the Audit emphasized the  
21 importance of sustaining the elevated level of tree trimming investments for at least  
22 two cycles before transitioning to more of a maintenance level program.<sup>26</sup> The

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<sup>24</sup> Case No. U-21305, Audit, Part Two, pg 33

<sup>25</sup> Michigan Public Service Commission Staff Comments on DTE Electric and Consumers Energy Audit Reports, MPSC Case No. U-21305, December 16, 2024. <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000RTl8zAAD>

<sup>26</sup> Case No. U-21305, Audit, Part Two, pgs. 69 – 70.

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1 Commission Staff likewise supports DTE Electric's tree trimming efforts.<sup>27</sup> The  
2 Company reiterates the importance of maintaining and investing in the vegetation  
3 management program to ensure the system remains on-cycle and mitigates  
4 vegetation interference with our overhead equipment. Moving forward, the  
5 Company is expanding its approach to a more holistic vegetation management  
6 approach that includes hazard tree removals both inside and outside of the right-of-  
7 way within which the Company's distribution system equipment is located. Time  
8 and time again, the Company has seen that progressive hazard tree removals are  
9 important to improving service reliability. As Company Witness Steudle explains,  
10 however, a single system-wide cycle length for the diverse set of distribution  
11 circuits may limit the Company's ability to optimize resources and reliability  
12 improvements. The Company sees an opportunity to start exploring a risk-based  
13 cycle driven by advanced modeling and field observations that strategically targets  
14 shorter cycles in areas with faster growing tree species to increase reliability, while  
15 avoiding excessive trimming in areas with fewer tree-related events.

16  
17 With respect to 4.8 kV and related targeted conversion efforts, the Audit recognizes  
18 the need for system conversions, but recommends prioritizing the specific  
19 investment projects necessary for increasing capacity<sup>28</sup>. As the Company clarified  
20 in its Reply Comments, over the next five years, all proposed 4.8 kV conversion  
21 projects are intended to address system capacity needs, and will include the other  
22 benefits of conversion, including wire down reductions and system reliability and  
23 operability improvements.

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<sup>27</sup> Case No. U-21534 6 TR 2989, 5146 and 6 TR 2983, 2996 and 5147

<sup>28</sup> Case No. U-21305, Audit, Part Two, pg. 85

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1 Finally, the Company agrees with the Audit's recommendation to dedicate  
2 resources to eliminate inspection and repair backlogs and prioritize the repair and  
3 replacement of equipment through inspections based on safety and reliability<sup>29</sup>.  
4 The Company continues to evaluate the impacts of the current backlogs and  
5 determine the appropriate pace to catch up on these backlogs. In this rate case, the  
6 Company is proposing a plan to meet the targeted inspection cycle. Company  
7 Witness Robinson addresses this issue and the associated funding request in his  
8 testimony.

9

10 **Q21. Do you have any other comments on the Audit's findings and**  
11 **recommendations?**

12 A21. The Company appreciates Liberty Consulting's professionalism and thoroughness  
13 in the Audit process and the recognition that the Company's plan for achieving  
14 meaningful improvement on the distribution grid is capable of bringing about such  
15 change. The Audit acknowledges and the Company understands that this effort will  
16 require considerable investment, and the Company is mindful of and working to  
17 mitigate the rate impacts for customers. That said, while the pace of investment is  
18 an important consideration, materially reducing necessary investments in the short-  
19 term will ultimately result in a long-term higher total cost, which will not benefit  
20 customers. As I explained in more detail above, the continued aging and  
21 deterioration of equipment during a period of delay will require investment with  
22 higher cost at a later date to address in-service failure as opposed to the proactive  
23 planned replacements the Company proposes. In addition to capital investments,  
24 prudent utility practice necessitates additional O&M expenditures today, including

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<sup>29</sup> Case No. U-21305, Audit, Part Two, pages 16-18

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1 proposed infrared thermography programs, cable testing and condition  
2 assessments, enhanced tree trimming, thorough asset inspections, and foundational  
3 improvements in data quality and processes. These efforts are essential for feeding  
4 accurate information into reliability analytics, ultimately delivering more efficient  
5 and reliable utility service. Company Witnesses Kryscynski, Rademacher and  
6 Robinson address these funding requests in their direct testimony.

7  
8 **PART IV: Strategic Programs Overview**

9 **Q22. Please provide an overview of the Company's strategic pillars.**

10 A22. The Company's DO strategic investment programs consist of four essential pillars:  
11 (1) Tree Trimming; (2) Infrastructure Resilience and Hardening; (3) Infrastructure  
12 Redesign and Modernization; and (4) Technology and Automation. Below is an  
13 overview of each pillar.

14  
15 **Tree Trimming:** DTE Electric has increased tree trimming efforts to address  
16 power outages caused by falling trees and limbs, which historically account for  
17 two-thirds of customer outages. Over the past five years, the Company has  
18 employed more than 1,300 trimmers. As of the end of 2024, the Company trimmed  
19 approximately 92% of its overhead circuit miles. The goal is to trim all 31,000  
20 overhead circuit miles to Enhanced Tree Trimming Program standards by the end  
21 of 2025. Company Witness Steudle supports this pillar in her direct testimony.

22  
23 **Infrastructure Resilience and Hardening:** The Infrastructure Resilience and  
24 Hardening pillar includes two key initiatives: enhancing the PTMM Program by  
25 increasing investment and aiming for a 10-year cycle to ensure structural integrity

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1 of the power poles and adding a five-year overhead detail inspection and  
2 remediation program, as well as completing the 4.8 kV Hardening Program in  
3 Detroit by 2027 to replace failing poles and equipment, which will improve  
4 reliability. Company Witness Robinson addresses this pillar in his direct testimony.

5 **Infrastructure Redesign and Modernization:** DTE Electric's original  
6 distribution system, largely built before 1965, requires modernization as it will  
7 continue to fall behind current and evolving electrification trends and reliability  
8 demands. The Infrastructure Redesign and Modernization pillar is designed to  
9 convert the old 4.8 kV ungrounded system to a modern 13.2 kV grounded system,  
10 which would enhance safety and reliability, and increase capacity for electric  
11 vehicles and distributed generation/storage. This involves significant system  
12 rebuilding and potential underground wire placement. Additionally, the Company  
13 plans to invest in the subtransmission system in order to address loading constraints  
14 and resolve system contingency constraints to provide reliable and secure power.  
15 Company Witness Stowe addresses this pillar in his direct testimony.

16  
17 **Technology and Automation:** DTE Electric plans to invest in smart grid  
18 technology to manage the increasing grid complexity and support improved  
19 reliability and faster restorations after an outage. This includes installing reclosers  
20 to maintain and improve outage response and safety, and fully automating the  
21 distribution grid. The foundation for this transition included the new Electric  
22 System Operations Center and Advanced Distribution Management System that  
23 became operational in 2023. Additional technology investments will support grid  
24 management, planning, and operations. Company Witness Rademacher addresses  
25 this pillar in his direct testimony.



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1     **Q23. How do the different pillars interconnect to support overall grid**  
2           **improvement?**

3     A23. Parts I and II of my testimony lay out the needs of the current state of the grid as  
4           well as the expected future grid needs due to increasing storm activity,  
5           electrification, and adoption of DG and DS technologies. Investments in each of  
6           the four pillars, as described below, address some of these needs, although it is only  
7           through the combined investments across all four pillars that current and future grid  
8           needs are fully met.

- 9                     • Tree Trimming: addresses current grid needs by improving near-term  
10                    reliability and safety. Maintaining and optimizing the tree trim cycle in  
11                    the long-term is also necessary to reduce the impact potential future  
12                    storm activity may have on the system.
- 13                    • Resilience and Hardening: primarily focused on meeting current grid  
14                    needs and a key driver of near-term reliability improvements. Like the  
15                    Tree Trimming Program, achieving a five-year PTMM cycle for  
16                    overhead equipment also addresses the future grid need of being more  
17                    resilient to increasing severe weather activity.
- 18                    • Redesign and Modernization: one of the most comprehensive pillars in  
19                    terms of meeting current and future needs. Near-term projects are  
20                    primarily driven by the needs for capacity relief and provide meaningful  
21                    reliability and safety benefits, yet the benefits of renewing the system  
22                    through 4.8kV Conversion, Subtransmission rebuilding, and System  
23                    Loading projects address all three future grid needs by building a system  
24                    that is more resilient to weather, increases capacity for electrification,  
25                    and supports higher penetration of DG and DS technologies. While the

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1 benefits of these projects are comprehensive, the pace at which the grid  
2 can be renewed is slower and the Company must continue to rebuild  
3 portions of the grid now coupled with investments in the other pillars.

4 • Technology and Automation: broad deployment of distribution  
5 automation such as reclosers, coupled with the previous investments in  
6 the Electric System Operations Center and Advanced Distribution  
7 Management System, will provide material near-term reliability  
8 benefits and also make the system more resilient to increasing storm  
9 activity by reducing the impact of outages. This pillar also addresses  
10 long-term grid needs by increasing the monitoring of load from electric  
11 vehicles, DG and DS technologies. While these monitoring capabilities  
12 are instrumental in managing an ever-more complex grid brought about  
13 by the dynamic bi-directional flow of electricity these capabilities must  
14 also be paired with an upgraded physical grid achieved through the  
15 projects found in the Redesign and Modernization pillar.

16

17 Combined, investments in the four pillars complement each other to provide  
18 comprehensive near-term reliability improvements and address the grid  
19 infrastructure needs that will take a longer time frame to execute.

20

21 **Q24. What is the overall capital investment and O&M expenditure Distribution**  
22 **Operations is requesting in this case?**

23 A24. The Company is requesting \$3.2 billion of Distribution capital investments for the  
24 24-month bridge period ending December 31, 2025 and \$1.9 billion of capital  
25 investments for the 12-month projected test year ending December 31, 2026, as

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1 shown in Exhibit A-12, Schedule B5.4, Page 1, Line 23, supported and sponsored  
2 by Witnesses Hill, Robinson, Stowe, Rademacher, and Steudle in base rates.

3  
4 The Company is including \$505.5 million of operation and maintenance (O&M)  
5 expenses in the projected test period as shown in Exhibit A-13, Schedule C5.6, Page  
6 1, Line 27, sponsored by Witnesses Kryscynski and Hartley.

7

8 **Q25. Why are these proposed levels of capital and O&M necessary?**

9 A25. The levels of capital investments and O&M expenses are necessary to achieve the  
10 goals of the Company, Commission, and other stakeholders and case participants  
11 to provide safe, reliable, and increasingly clean electricity to DTE Electric  
12 customers. These investments also lay the foundation for the grid modernization  
13 needed to support our customers' evolving needs for greater resiliency in the face  
14 of increasingly frequent and severe storms, electrification, and the integration of  
15 distributed energy resources.

16

17 **Q26. Why is the Company seeking an increased level of O&M in this proceeding**  
18 **when compared to past rate cases?**

19 A26. There is a need for additional foundational grid activity beyond the amount  
20 supported by current rates. This includes increased maintenance associated with a  
21 more complex and increasingly sophisticated grid where additional devices are  
22 connected, and changing load dynamics that must be more closely monitored and  
23 controlled in new ways. Recognizing the large amount of investment necessary to  
24 upgrade the vast aging infrastructure across the entire grid, the Company is also  
25 prudently applying corrective maintenance where appropriate instead of complete

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1 replacement. Company Witness Kryscynski details the O&M request in his direct  
2 testimony.

3

4 **Q27. Does the Company incorporate environmental justice considerations in the**  
5 **selection and prioritization of its distribution investments?**

6 A27. Yes. Environmental justice is an important consideration in the Company's overall  
7 distribution investment allocations across the DTE Electric service area. Company  
8 Witness Kryscynski addresses the Company's environmental justice analysis  
9 conducted as part of his direct testimony in this proceeding to ensure that vulnerable  
10 customers are prioritized appropriately both within the proposed rate case  
11 investments and within the Infrastructure Recovery Mechanism (IRM). This  
12 analysis shows that vulnerable communities are receiving high levels of  
13 distribution-level grid investment, resulting in improving reliability metrics for  
14 those customers.

15

16 **Q28. Does the Company anticipate continued investment in the grid to support its**  
17 **safety and reliability objectives?**

18 A28. Yes. This case is focused on the investments and expenses required to lay the  
19 foundation for grid modernization in the 2026 projected test year, however, the  
20 Company will continue to invest in the years beyond the current rate case.  
21 Investments beyond the projected test year are required to achieve both the  
22 Company's and customers' expectations of an increasingly resilient and reliable  
23 grid. As such, the Company believes it is appropriate to expand its IRM to include  
24 key strategic investment programs beyond the projected test year. Company  
25 Witness Willis describes the proposal to extend the IRM through calendar year

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1 2029 and the benefits it brings to DTE Electric customers. Company Witnesses  
2 Robinson, Stowe, and Rademacher support the specific investment programs and  
3 costs in their respective testimony.

4

5 **PART V: GPM / Reliability Models and Benefit-Cost Analysis**

6 **Q29. How does the Company identify, select, and prioritize its capital strategic**  
7 **investments?**

8 A29. The Company prioritizes its investment proposals based using two Company-  
9 developed models: the Global Prioritization Model (GPM) and the Reliability  
10 Model. These models consider a variety of benefit attributes, including safety,  
11 customer requirements, operational need, and project cost to rank priorities for  
12 projects that are needed in the DTE Electric system. While these models naturally  
13 encompass a level of benefit-cost analysis, in response to feedback from the  
14 Commission<sup>30</sup>, the Company is also presenting a more comprehensive benefit-cost  
15 analysis with respect to certain programs and projects in this rate case.

16

17 **Q30. What is the GPM?**

18 A30. The GPM is a tool designed by the Company's DO team to prioritize investments  
19 by ranking projects and programs according to the benefits they provide for a  
20 certain level of investment. The model was initially developed in 2018 and has  
21 gone through iterative and continuous improvements over the years. As noted in  
22 the Audit, the prioritization ranking utilizes an economic evaluation method—the  
23 “best fit, most reasonable cost”<sup>31</sup> method—to prioritize projects. The recent  
24 transparency in developing and executing the model has been positively received

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<sup>30</sup> Case No. U-21534 January 23, 2025 Order, pages 108, 142, 148, and 154

<sup>31</sup> Case No. U-21305, Audit Report, Part Two, pg. 14-15

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1 by both the Commission in its 2024 rate case order.<sup>32</sup> While certain aspects of the  
2 GPM may continue to be improved over time, it provides a rigorous and accepted  
3 methodology for evaluating the priority of investments to meet the grid needs  
4 identified in the Company's grid modernization process.

5  
6 The GPM ranking was previously achieved by assessing a project across ten impact  
7 dimensions, which represent the potential benefits of proposed projects, and  
8 calculating a total project score based on the weight of each dimension. While the  
9 Company is confident in the output of the GPM model as used in Case No. U-  
10 21534, DTE Electric has a culture of continuous improvement and is always  
11 working to further optimize the analytics driving its capital project selections. In  
12 this case, as described by Company Witness Kryscynski in his direct testimony, the  
13 Company is proposing slight modifications to the GPM, which will streamline the  
14 evaluation to use eight impact dimensions instead of ten. Witness Kryscynski also  
15 presents the results of the GPM analysis and explains how that analysis drives the  
16 Company's investment proposals in this case.

17  
18 **Q31. What is the Reliability Model?**

19 A31. The Reliability Model is another vehicle for prioritizing the Company's DO  
20 projects that are focused on reliability improvements. Unlike the GPM, the  
21 Reliability Model evaluates reliability performance metrics (SAIFI and/or SAIDI)  
22 based on data from actual outage events. It also forecasts, on a circuit-level basis,  
23 how reliability will be improved as a result of the proposed project. Company

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<sup>32</sup> Case No. U-21534 January 23, 2025 Order, page 97

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1 Witness Kryscynski describes the Reliability Model in more detail and presents the  
2 results of its analysis in his direct testimony in this proceeding.

3

4 **Q32. Besides the GPM and the Reliability Model, does the Company use other**  
5 **approaches to conduct benefit-cost analyses?**

6 A32. The GPM and Reliability Model incorporate certain components of benefit-cost  
7 analysis, so weighing of costs and benefits already happens as part of the  
8 Company's modeling process. However, the Company has heard the Commission's  
9 feedback, as noted above, that additional benefit-cost analysis would be helpful in  
10 evaluating the various capital requests.

11

12 Certain customer benefits, like safety and resiliency, are difficult to quantify or  
13 monetize as these concepts do not lend themselves to having a quantified dollar  
14 value, therefore, they have been considered on a largely qualitative basis. The  
15 Company agrees with the Commission that "conducting a complete benefit-cost  
16 analysis for every investment category is neither practical nor advisable."<sup>33</sup>

17

18 **Q33. How is the Company including additional benefit-cost analysis in its**  
19 **investment planning in this case?**

20 A33. DTE Electric began incorporating additional benefit-cost analysis into its case in  
21 2024 and noted that it was doing a new type of benefit-cost analysis specifically for  
22 the PTMM and certain underground programs, with plans to continue growing its  
23 use of this methodology. For example, in the area of vegetation management, in  
24 light of the emergence of remote sensing and advanced data analytics for vegetation

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<sup>33</sup> Case No. U-21534 January 23, 2025 Order, pg. 97

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1 management programs, the Company is moving towards a variable, risk-based  
2 cycle for tree trimming that will refine the current maintenance program by setting  
3 trim cycles based on known growth rates, which will help to optimize spending to  
4 achieve the greatest benefit. This analysis will help the Company quantify the  
5 safety and resiliency benefits of proposed improvements by putting more certainty  
6 and data around the impact of external factors that were previously not modeled.

7  
8 The Company has also engaged 1898 & Co. ("1898"), an engineering consultancy  
9 with extensive experience performing reliability investment benefit cost analyses  
10 in many regulatory jurisdictions, to model and quantify additional benefit-cost  
11 analyses associated with the Company's updated approach to PTMM and  
12 undergrounding and expanded the benefit cost analysis (BCA) to include  
13 Distribution Automation and associated telecommunication needs. Company  
14 Witnesses Robinson and Rademacher address these issues respectively in greater  
15 detail in their direct testimony, as does Company Witness De Stigter, the Director  
16 of Utility Investment Planning in 1898's Utility Consulting Practice, with respect  
17 to benefit-cost analyses for the programs.

18

19 **Q34. What is the interplay of the GPM, Reliability Model, and Benefit-Cost**  
20 **Analysis in the Company's strategic planning and project evaluation**  
21 **process?**

22 A34. When combined with the rigorous analytical tools already deployed in the  
23 Company's investment planning process, a renewed emphasis on bolstered benefit-  
24 cost analysis allows the Company to provide thoughtfully developed and well-  
25 supported proposals that address pressing system issues while ensuring those



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1 projects provide strong customer value. The complement of the three analytical  
2 tools provides a strong framework for ranking and selecting projects and the  
3 supporting benefit valuation that these investments will provide for our customers.

4

5 **PART VI: Capital Variance – Distribution Operations**

6 **Q35. Please explain the variances between the capital investment authorized by**  
7 **the Commission and actual capital investment.**

8 A35. Overall, the Company deployed \$1.554 billion of capital in 2024 as compared to  
9 the \$1.425 billion authorized in Case No. U-21534. The table below lists the high-  
10 level categories of the Company's capital plan for the recent rate cases for the 2024  
11 calendar years.<sup>34</sup> These incremental capital expenditures are necessary investments  
12 to support the ordinary (although constantly evolving) customer needs in DTE  
13 Electric's 7,600 square mile service territory. Witnesses Hill, Robinson, Stowe,  
14 and Rademacher discuss these expenditures with further details in their respective  
15 testimony. On balance, the Company's projections of system needs and  
16 expenditures are on target, reasonable, and prudent, and are closely aligned with  
17 the Company's demonstrated actual financial needs.

---

<sup>34</sup> The dollar amounts shown in the Table 2 exclude the amounts authorized for recovery through the Investment Recovery Mechanism (IRM).

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1                   **Table 2        Comparison of the Capital Plan in the Recent Rate Cases**  
2                                   **(U-21534 and U-21860 for 2024, \$ millions)**

| Base/Strategic | Category                                     | 2024<br>U-21534<br>Request | 2024<br>U-21534<br>Order | 2024<br>U-21860<br>Actual | % Variance<br>between U-<br>21534 Order<br>and U-21860<br>Request |
|----------------|----------------------------------------------|----------------------------|--------------------------|---------------------------|-------------------------------------------------------------------|
| Base           | Emergent Replacements                        | \$493                      | \$448                    | \$472                     | 5%                                                                |
| Base           | Customer Connections,<br>Relocations & Other | \$303                      | \$270                    | \$349                     | 29%                                                               |
| Strategic      | Infrastructure Resilience<br>and Hardening   | \$295                      | \$295                    | \$320                     | 8%                                                                |
| Strategic      | Infrastructure Redesign<br>and Modernization | \$291                      | \$291                    | \$266                     | -9%                                                               |
| Strategic      | Technology and<br>Automation                 | \$122                      | \$120                    | \$148                     | 23%                                                               |
| <b>Total</b>   |                                              | <b>\$1,505</b>             | <b>\$1,425</b>           | <b>\$1,554</b>            | <b>9%</b>                                                         |

3

4   **Q36.    What are some of the reasons for these variances?**

5   A36.    In the course of operating a large power grid such as DTE Electric’s system, there  
6            are many external factors that surface between the time when the original capital  
7            plan was developed and the respective year of actual capital deployment. Based on  
8            the strategy outlined in the DGP, each year, the Company builds the capital forecast  
9            for future years based on the needed investments described earlier and incorporates  
10          various inputs and operating experience to factor in externalities such as weather  
11          conditions, regional development, and supply chain marketplace dynamics to  
12          determine the timing and pacing of these capital deployments within a given  
13          calendar year. There is also the continuous wear and tear on our existing assets  
14          leading to unavoidable breakdowns. When there is a larger than expected storm  
15          condition, the Company will shift resources from capital deployment to ensuring  
16          speedy service recovery. When there are new customer developments that are  
17          progressing at a faster pace than originally anticipated, the Company will shift  
18          resources to address the needs of line extensions to connect these new loads. For

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1 reasons like these, the actual capital spent in the base categories of Emergent  
2 Replacement, Customer Connection, Relocation and Others could be higher than  
3 originally forecasted, as is the case for both 2023 and 2024. These expenditures  
4 facilitated necessary system upgrades or improvements to continue safe and reliable  
5 service to customers and were reasonably and prudently incurred. On the other  
6 hand, other externalities such as agency permitting delays and seasonal loading  
7 contingencies can also impact the availability of outage windows where existing  
8 equipment could be shut down for proactive replacement, and as a result, the  
9 Company will experience delays in capital deployment, particularly in the area of  
10 Infrastructure Redesign and Modernization, where the project scopes are typically  
11 more extensive and more complex. 2023 and 2024 variance commentary are  
12 provided respectively in Exhibit A-23, Schedules M1, and M2; and 2025 variance  
13 schedule is found in M3.

14  
15 **PART VII: Municipal Project Coordination**

16 **Q37. What did the Commission Order in MPSC Case No. U-21534 require in**  
17 **regard to municipal project coordination?**

18 A37. The Commission stated on page 468 that:

19 “DTE Electric Company shall take proactive measures to inform  
20 municipalities and other utilities of projects it plans to commence prior to  
21 earmarking capital for the project” and “DTE Electric Company shall take  
22 proactive measures to investigate publicly available plans provided by other  
23 utilities and municipalities in an effort to coordinate work.”

Line  
No.

1     **Q38. Can you describe how the Company takes proactive measures to inform**  
2     **municipalities and other utilities of projects it plans to commence?**

3     A38. Yes. The Company informs municipalities and other utilities of its forthcoming  
4     projects through a variety of existing engagement mechanisms. For each  
5     community in the Company’s service area, there is a Regional Affairs manager who  
6     serves as the designated liaison between the Company and the community. The  
7     Regional Affairs managers are typically well known by community officials and  
8     are usually the first point of contact for a broad variety of topics, including project  
9     coordination that is supported by the engineering and project team from within the  
10    Company. Examples of coordination with these representatives include holding  
11    monthly community lighting meetings, providing reliability and resiliency updates  
12    to local elected officials in municipal governments, holding project coordination  
13    meetings (with both DTE Electric and DTE Gas), making presentations to City  
14    Council, engagement with Historic Commission and neighborhood associations,  
15    community and project open houses, general community outreach, and direct  
16    customer communication.

17

18    **Q39. In addition to the direct engagement with communities discussed above, what**  
19    **tools are available for municipalities and other utilities to see information**  
20    **about the Company’s projects?**

21    A39. In 2024, the Power Improvements Map (“PIM”) was launched and replaced the  
22    prior DTE Electric Reliability Improvements Map. The updated tool provides  
23    localized information about current, planned and past infrastructure repairs and  
24    upgrades. PIM shows work along our four essential pillars: (1) Trimming Trees  
25    (Tree Trimming); (2) Updating existing infrastructure (Infrastructure Resilience

Line  
No.

1 and Hardening); (3) Rebuilding material portions of the grid (Infrastructure  
2 Redesign and Modernization); and (4) Transitioning to a smart grid (Technology  
3 and Automation). This means that anyone can enter a county, city, zip code or  
4 personal address into the map and see what grid improvement work is currently in  
5 progress, planned over the next two years, or completed over the past three years.  
6 The map provides a localized view of reliability performance for a given area after  
7 the end of each calendar year, beginning with 2023. By using the PIM, all  
8 stakeholders, including elected and appointed officials, community leaders,  
9 regulatory officials, environmental justice advocates, customers, along with the  
10 media and others, can see the work the Company is doing and in a format that is  
11 accessible and transparent. The PIM is accessible through the Company's website,  
12 and can also be found directly at: <https://dteenergy.com/powermap>.

13

14 **Q40. What additional proactive measures has the Company taken to inform**  
15 **municipalities and other utilities of its planned projects and to investigate**  
16 **plans of other utilities and municipalities?**

17 A40. Coordination of projects at the state level is facilitated, in part, by the Michigan  
18 Infrastructure Council ("MIC"), which was formed under Public Act 323 of 2018.  
19 The MIC's mission "is to cultivate partnerships that strengthen Michigan's  
20 Infrastructure to provide the foundation for public and environmental health,  
21 economic prosperity, and quality of life."<sup>35</sup> The MIC is actively working to  
22 coordinate and collaborate with entities throughout Michigan. The MIC Project  
23 Portal ("MiDIG") is "intended to assist authorized infrastructure asset owners and  
24 managers, private utilities, and state agencies across the State of Michigan with

---

<sup>35</sup> About the Michigan Infrastructure Council, available at <https://www.michigan.gov/mic/about>, accessed on March 16, 2025.

Line  
No.

1 cross asset collaboration and coordination.”<sup>36</sup> DTE Electric is collaborating on the  
2 user agreement with the MIC to share electric and gas capital construction projects  
3 on the statewide portal. Next, the Company is expecting to test providing the  
4 project information to the MIC Project Portal early in the second quarter of 2025,  
5 and if all goes well, the Company expects to be uploading project information to  
6 the MIC Project Portal early in the third quarter of 2025.

7

8 **Q41. Does this complete your direct testimony?**

9 A41. Yes.

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<sup>36</sup> MIC Project Portal, available at <https://www.michigan.gov/mic/project-portal> , accessed on March 16, 2025.

**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-21860

QUALIFICATIONS  
  
AND  
  
DIRECT TESTIMONY  
  
OF  
  
ALLEN J. KRYSCYNSKI JR

**DTE ELECTRIC COMPANY**  
**QUALIFICATIONS AND DIRECT TESTIMONY OF ALLEN J. KRYSCYNSKI**

Line  
No.

**Background & Qualifications**

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

3     A1.     My name is Allen J. Kryscynski, and my business address is One Energy Plaza,  
4             Detroit, Michigan, 48226. I am employed by DTE Electric Company (“DTE  
5             Electric” or the “Company”).

7     **Q2.     On whose behalf are you testifying?**

8     A2.     I am testifying on behalf of DTE Electric.

10    **Q3.     What is your educational background?**

11    A3.     I earned a Bachelor of Science from the University of Michigan School of Natural  
12             Resources and Environment with a dual concentration in environmental policy and  
13             natural resource management. I also received a master’s degree in Business  
14             Administration (MBA) from the University of Michigan.

16    **Q4.     Please summarize your professional experience.**

17    A4.     I held several positions with ITC Holdings, including as Senior Regulatory Analyst,  
18             and a variety of positions within the Local Community and Community Affairs  
19             team, culminating as a Senior Local Government and Community Affairs  
20             Representative. At ITC Holdings, I worked on Federal Energy Regulatory  
21             Commission (“FERC”) and Midcontinent Independent System Operator (“MISO”) regulatory  
22             issues and represented ITC Holdings at community meetings regarding  
23             new transmission substations and transmission lines.



Line  
No.

1 I joined DTE Energy in 2014 as a Strategy and Corporate Development Associate  
2 in the Corporate Strategy group. In this role, I did work on the initial Distribution  
3 Operations (“DO”) investment strategy project to determine distribution grid  
4 investment needs as well as work on DTE workforce projections and requirements  
5 for both the DO and Fossil Generation business units. In 2016, I was appointed  
6 Manager of Distribution Operations Strategy and assumed responsibility for  
7 continued work to evolve the distribution operations investment strategy,  
8 operations strategy, and the chief of staff role for the Senior Vice President of  
9 Distribution Operations. In early 2018, I was appointed Manager in Project  
10 Management with responsibility to start and operationalize the 4.8kV Hardening  
11 Program to remove City of Detroit arc wire and harden the City of Detroit electrical  
12 infrastructure. Later in 2018, I was appointed Manager of Tree Trim Strategy,  
13 where I was responsible for managing the initial Tree Trim Surge rate case, Tree  
14 Trim contractor negotiations, the Tree Trim strategy for scheduling work, and  
15 providing an adequate supply of tree trimmers necessary to complete the work. In  
16 2020 I took over the Tree Trim Operations Manager position and managed day-to-  
17 day Tree Trim operations, including overseeing all of DTE Electric’s internal  
18 arborists and foresters as well as eight tree trim contractors and their 1,600+  
19 employees. In 2022 I was appointed as Manager of Distribution Operations  
20 Regulatory Strategy and Grid Modernization, and promoted to Director in 2023.

21

22 **Q5. What are your current duties and responsibilities?**

23 A5. As Director of Distribution Operations Long Term Capital Planning and Regulatory  
24 Operations, I have two primary areas of responsibility: 1) managing Distribution  
25 Operations regulatory activities, including rate cases, the Distribution Grid Plan

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1 filing, required reporting, and various Company/MPSC collaboratives, and 2)  
2 Distribution Operations long term grid modernization strategy and the distribution  
3 grid plan (“DGP”).  
4

5 **Q6. Have you previously sponsored testimony before the Michigan Public Service**  
6 **Commission (“MPSC” or the “Commission”)?**

7 A6. Yes. I sponsored testimony in Case Nos. U-21534 and U-21297. In addition, I  
8 supported Tree Trim testimony and witnesses in Case Nos. U-20162, U-20561, and  
9 U-20836.

10 **Overview and Executive Summary**

11 **Q7. Please summarize your testimony.**

12 A7. I present an overview of the Company’s Distribution Operations related proposed  
13 expenditures. Distribution operations are at the center of the customer experience  
14 and play a crucial role in how the Company keeps the lights on for its customers’  
15 homes and businesses. On top of the normal cost of continuing to prudently operate  
16 the system, the Company is proactively addressing the reality, acknowledged by  
17 the Liberty Audit (“Audit”) <sup>1</sup>, that its system is aging, and additional and sustained  
18 investment is needed to safely and reliably serve customers in the long term. To  
19 that end, the Company is requesting \$505.5 million in Operations and Maintenance  
20 (“O&M”) expenses in the test year to enhance the reliability, safety, and resilience  
21 of the electric distribution system. My testimony explains how this funding

---

<sup>1</sup> The DTE Electric Utility Distribution Audit Report (“Liberty Audit”) was conducted by Liberty Consulting Group and filed in Case No. U-21305. Though the title indicates DTE Energy Company (DTE Energy), the audit findings apply to DTE Electric, a wholly owned subsidiary of DTE Energy. The DTE Electric Audit Reports are available in filing ## U-21305-0012 and U-21305-0013 at <https://mi-psc.my.site.com/s/case/5008y000005KkdgAAC/> (accessed February 15, 2025)

Line  
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1 supports critical maintenance, infrastructure improvements, and workforce  
2 expansion to meet both growing demand and evolving challenges.

3

4 In addition to the Company's O&M request, I explain how the Company  
5 strategically selected capital projects presented in this case through use of its Global  
6 Prioritization Model ("GPM") and Reliability Model. Using several impact  
7 dimensions, the GPM transparently and effectively ranks potential projects based  
8 on the benefits they would deliver for a given level of investment. In this case, the  
9 Company proposes slight tweaks to optimize that model based on its experience  
10 employing it to date. The Reliability Model estimates tangible reliability  
11 improvements associated with proposed capital investments in a data-driven  
12 framework on a circuit-by-circuit basis. This rigorous analysis produces high  
13 confidence in the prioritization and reliability impact for each of the selected  
14 projects.

15

16 In previous cases, the Company has described efforts to pursue Infrastructure  
17 Investment and Jobs Act ("IIJA") funding through several available grants. While  
18 the Company was selected for one grant, negotiations with the federal government  
19 stalled with the new administration taking office. Because it is not clear what, if  
20 any, future grant funding may be available, the Company is not including any IIJA  
21 funding in this case.

22

23 Finally, I discuss the Company's ongoing commitment to advance environmental  
24 justice ("EJ"). The Company considers EJ by 1) incorporating EJ considerations  
25 in investment decisions through use of an EJ multiplier in the GPM model; 2)

Line  
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1 improving system performance for vulnerable communities experiencing poor  
2 reliability through the distribution investment programs; and 3) providing support  
3 to vulnerable customers experiencing outages during storms through community  
4 outreach efforts. The Company is proud to report that, based on an analysis of  
5 System Average Interruption Duration Index (SAIDI) and System Average  
6 Interruption Frequency Index (SAIFI) metrics by census tract, the Company's most  
7 vulnerable customers are, on average, experiencing more reliable electric service  
8 than the rest of the system. Similarly, an evaluation of investments shows that a  
9 meaningful portion of the Company's reliability improvement work is being  
10 conducted in vulnerable communities. The Company will continue investing in EJ  
11 communities through the programs and projects presented in this case.

12

13 **Q8. What is the purpose of your testimony?**

14 A8. The purpose of my testimony is to support, as reasonable, prudent, and necessary,  
15 the historical O&M expenses related to electric distribution activities for the 2023  
16 historical period and projected expenses for 2024 through December 31, 2026.  
17 Additionally, my testimony describes and supports (1) the Distribution O&M  
18 overview, (2) the Company's GPM, (3) the Company's Reliability Model, (4) the  
19 Company's efforts in securing IIJA funding grants for DO projects, and (5) the  
20 Company's approach to EJ, with corresponding exhibits.

21

22 **Q9. How is your testimony organized?**

23 A9. My testimony consists of five parts:

24 Part I Distribution O&M Overview and Exhibits

25 Part II Global Prioritization Model

Line  
No.

1 Part III Reliability Model  
2 Part IV IIJA Grant Opportunities  
3 Part V Environmental Justice  
4

5 **Q10. Are you sponsoring any exhibits in this proceeding?**

6 A10. Yes. I am sponsoring the following exhibits:

| 7  | <u>Exhibit</u> | <u>Schedule</u> | <u>Description</u>                                       |
|----|----------------|-----------------|----------------------------------------------------------|
| 8  | A-13           | C5.6            | Projected Operation and Maintenance Expenses –           |
| 9  |                |                 | Distribution Expenses                                    |
| 10 | A-23           | M12             | Reliability Model                                        |
| 11 | A-23           | M14             | Global Prioritization Model Project and Program Rankings |
| 12 | A-23           | M14.1           | Global Prioritization Model                              |

13

14 **Q11. Were these exhibits prepared by you or under your direction?**

15 A11. Yes, they were.  
16

17 **PART I: Distribution O&M Overview and Exhibits**

18 **Q12. What level of O&M spending is the Company proposing for the projected test**  
19 **period to support Distribution Operations in operating and maintaining the**  
20 **grid?**

21 A12. The Company is proposing \$505.5 million of O&M expenses to support  
22 Distribution Operations in the projected test period as shown in Exhibit A-13,  
23 Schedule C5.6, Page 1, Line 27. This consists of approximately \$143.0 million in  
24 projected distribution operation expenses and approximately \$362.5 million of  
25 maintenance expenses.

Line  
No.

1   **Q13. What operations and maintenance activities are included in the O&M exhibit**  
2       **for Distribution Operations?**

3   A13. Included in Exhibit A-13, Schedule C5.6 are key activities necessary for managing  
4       the operations and maintenance of the Company's distribution system. These  
5       include operation expenses related to supervision, engineering, load dispatching,  
6       station, overhead and underground line operations, and customer meter and  
7       installation activities, among other distribution costs. It also includes maintenance  
8       costs, which focus on inspecting, repairing, sustaining, and enhancing the  
9       distribution infrastructure, with funds allocated for the upkeep of station equipment,  
10      overhead and underground lines, and line transformers. I address certain major  
11      O&M cost components later in my testimony while other cost components are  
12      addressed in more detail by other witnesses. For example, Company Witness  
13      Hartley addresses street lighting and signal systems, and Company Witness Steudle  
14      addresses tree trim expenses.

15

16   **Q14. What do the line items listed under Distribution Expenses in Exhibit A-13,**  
17       **Schedule C5.6 describe?**

18   A14. The costs associated with dispatching, coordinating restoration, and tree trim efforts  
19       are included in FERC accounts 580 (Operation Supervision and Engineering) and  
20       581 (Load Dispatching). Accounts 582 (Station Expenses), 583 (Overhead Line  
21       Expenses), 584 (Underground Line Expenses), and 588 (Miscellaneous Expenses)  
22       incorporate the costs for developing and implementing training and work force  
23       planning for the Company's substation operators and maintenance personnel,  
24       apprentice lineman, splicers, technicians, engineers, riggers, and planners as well  
25       as the staff groups to support these critical efforts. Job skills training is conducted

Line  
No.

1 for the safety of employees and the public. Witness Hartley supports account 585  
2 (Street Lighting and Signal System Expense). Meter testing and distribution costs  
3 are incorporated into account 586 (Meter Expenses). Account 587 (Customer  
4 Installations Expenses) includes expenses to support the specific needs of  
5 customers served at primary voltages. Account 589 (Rents) reflects the expenses  
6 associated with leased facilities and attaching to poles not owned by the Company.

7

8 **Q15. Can you provide an overview of the Company's O&M cost request and explain**  
9 **why these costs are essential to delivering safe and reliable service?**

10 A15. Yes. The Company's core responsibility is to provide safe, reliable, and cost-  
11 effective electric service for customers who depend on this essential service to  
12 support their homes, businesses, and livelihoods. The Company takes that  
13 responsibility seriously, and DO team is at the center of executing on this core  
14 function. While DTE Electric is proposing a variety of initiatives to improve  
15 various components of its service across its broader operations, the Company's DO-  
16 related O&M costs request reflects the necessary funding to accomplish its most  
17 basic and essential purpose - maintaining and sustaining a power delivery system  
18 that keeps the lights on for customers. Just as routine vehicle maintenance is  
19 essential to keep a car reliably running, the presented O&M costs represent work  
20 the Company must do to keep its distribution system functioning.

21

22 Furthermore, as discussed in Witness Chiu's testimony, the Company's electrical  
23 grid is aged and in need of attention. O&M is essential to sustained operations.  
24 Witness Robinson highlights the Audit findings, which identified backlogs of both  
25 Preventive and Corrective Maintenance that must be executed to sustain and repair

Line  
No.

1 the electrical grid. Additionally, Witness Steudle explains the critical importance  
2 that tree trimming plays to continue to improve the Company's reliability  
3 performance.

4  
5 The O&M costs supported in my testimony and in this case are targeted to critical  
6 maintenance activities as well as needed system repairs. The O&M cost request is  
7 designed to ensure the continued delivery of high-quality service to customers  
8 while accounting for the evolving demands on the grid. The determination of O&M  
9 expenses accounts for, among other things, inflation-adjusted historical costs,  
10 known and measurable changes, and projected operational needs. The request also  
11 considers external factors such as the increased frequency of severe weather events,  
12 which directly influence restoration costs and necessitate prudent planning for  
13 future system resiliency. In this section, I describe the specific maintenance  
14 activities included in this request and explain how these costs were derived and  
15 adjusted to reflect projected needs.

16  
17 **Q16. What do the line items listed under Maintenance in Exhibit A-13, Schedule**  
18 **C5.6 describe?**

19 A16. Maintenance work is critical to providing safe and reliable service. Account 591  
20 (Maintenance of Structures) is to support the maintenance of existing physical  
21 structures associated with the electric distribution system such as substation control  
22 buildings. Restoration, troubleshooting and reactive maintenance work associated  
23 with substation, overhead and underground equipment is included in accounts 592  
24 (Maintenance of Station Equipment), 593 (Maintenance of Overhead Lines), and  
25 594 (Maintenance of Underground Lines), respectively. In addition, account 593



Line  
No.

1 includes the tree trim expenses supported by Company Witness Steudle. The  
2 supervision and other support costs for these important efforts are included in  
3 account 590 (Maintenance Supervision and Engineering). Company Witness  
4 Hartley supports account 596 (Maintenance of Street Lighting and Signal Systems).

5  
6 **Q17. How was the projected O&M expense amount in column (l) of Exhibit A-13,**  
7 **Schedule C5.6, page 1, derived?**

8 A17. First, the 12-month historical test period column (c) was adjusted for eliminations  
9 and temporary adjustments (i.e., eliminate Transitional Reconciliation Mechanism  
10 - “TRM”<sup>2</sup>) in columns (d) and (e) to arrive at the adjusted 12-month historical  
11 balance. Second, the adjusted 12-month historical test period in column (f) is  
12 adjusted for inflation, column (g) to (i), and other expected changes, column (j).

13  
14 **Q18. Can you explain the “eliminate TRM” adjustment and normalization**  
15 **adjustments reflected in columns (d) and (e), respectively on Exhibit A-13,**  
16 **Schedule C5.6?**

17 A18. Column (d) shows rate case adjustments of \$0.1 to eliminate expenses recovered  
18 through the TRM. Column (e) on line 27 is an O&M decrease of \$60.9 million that  
19 includes a decrease of \$91.0 million for restoration expenses offset by the  
20 normalization of \$30.1 million for temporary cost reductions in 2023. I discuss this  
21 normalization in more detail below.

---

<sup>2</sup> The TRM concluded in 2022 and was part of the Detroit Public Lighting transition of retail customers to DTE Electric.

Line  
No.

1 **Q19. How is the \$91.0 million of restoration normalization calculated and how does**  
2 **it relate to the 2023 actual spend?**

3 A19. As presented on page 3 of Exhibit A-13, Schedule C5.6, the Company forecasted  
4 restoration costs using a five-year average to develop the projected test year in the  
5 instant case. This averaging method smooths out year-to-year variation, which has  
6 the effect of moderating the variable cost impacts of extreme weather over time.  
7 The Commission has supported this methodology in previous rate cases, including  
8 in the most recent U-21534 Order.<sup>3</sup> The approximately \$91.0 million normalization  
9 adjustment is the difference between the five-year average and the 2023 actual.

10

11 **Q20. Did the Company use constant dollar averaging of historical costs to develop**  
12 **its cost forecast in the instant case?**

13 A20. Yes. Constant dollar averaging of historical costs is a necessary step in developing  
14 cost forecasts because inflation over time reduces the purchasing power of goods  
15 and services. The five-year average of restoration costs includes an adjustment for  
16 inflation. This adjustment is presented on Exhibit A-13, Schedule C5.6, page 3.  
17 Refer to Company Witness Lyons for further discussion regarding historical  
18 inflation. Company Witness Lyons' testimony supports the Company's use of  
19 constant dollar averaging to develop its cost forecasts. Specifically, his testimony  
20 demonstrates that constant dollar averaging is consistent with economic principles,  
21 ensures cost forecasts adjust for inflationary trends, and is a recognized practice in  
22 developing cost forecasts.

23

24 **Q21. What makes up the \$30.1 million of temporary cost reductions in 2023?**

---

<sup>3</sup> Case No. U-21534 Order, January 23, 2025, p. 221. ("2024 Order")

Line  
No.

1 A21. The details are listed in footnote 4 of Exhibit A-13, Schedule C5.6, page 2 and  
2 include \$16.7 million of temporary reductions for contractor spend for non-safety  
3 or non-reliability critical maintenance activities, \$7.0 million related to deferred  
4 hiring as well as reductions in training and overtime, \$4.2 million due to a  
5 temporary pause in the purchases of supplies and materials, \$1.2 million in  
6 temporary reductions in travel and telecom spend and \$0.9 million of year-over-  
7 year variability in damage claims collections. These temporary reductions were  
8 taken to mitigate the financial challenges experienced by the Company in 2023 as  
9 further discussed by Witness Bruzzano and are not planned to recur in the projected  
10 test period.

11

12 **Q22. What projected adjustments did you make to O&M as reflected in columns (g)**  
13 **through (i)?**

14 A22. Increases based on the inflation rate, as described by Company Witness Uzenski,  
15 were applied to the adjusted historical test period expenses for the period January  
16 2024 through December 2026.

17

18 **Q23. What changes are shown in the Other Adjustments in column (j) of Exhibit A-**  
19 **13, Schedule C5.6, page 1?**

20 A23. These changes are known and measurable adjustments to Distribution expenses in  
21 order to account for costs that can be specifically identified, quantified, and tracked.  
22 Exhibit A-13, Schedule C5.6, page 2, footnote 6, details all items in Other Projected  
23 Adjustments as well as the witnesses that support these adjustments. Notable  
24 changes include:

Line  
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- 1 • Maintenance of Overhead Lines-Tree Trim, Line 19, highlights a \$74.6
- 2 million increase in Tree Trim base O&M needed to maintain the current tree
- 3 trim maintenance schedule, as well as including the introduction of risk-
- 4 based cycles and proposed specification changes the Company is exploring.
- 5 This adjustment is discussed further by Company Witness Steudle.
- 6 • Adjustments related to Preventative Maintenance Backlog, Pole Top
- 7 Maintenance and Modernization (“PTMM”) program inspections,
- 8 Corrective Maintenance, and System Cable Testing program result in an
- 9 increase of \$27.1 million. These adjustments, which align to Audit
- 10 recommendations, represent costs associated with the upkeep and reliability
- 11 improvements of critical substation assets, related infrastructure, pole
- 12 replacements, conductor upgrades, other structural repairs, underground
- 13 cable maintenance, and inspections, as discussed further by Company
- 14 Witness Robinson. These expenses are spread over multiple lines in Exhibit
- 15 A-13, Schedule C5.6, page 1.
- 16 • An adjustment of \$8.3 million is required for additional engineering and
- 17 support personnel needed to support the Company’s current investment
- 18 plan.

19

20 **Q24. Why is the Company proposing to increase its engineering and support**  
21 **personnel?**

22 A24. The Company’s need for additional engineering personnel is driven by the  
23 increasing complexity and scale of its distribution system transformation. Looking  
24 ahead, a strong engineering workforce is needed to support the Company’s growth  
25 and reliability improvement efforts. For example, this support will be essential to

Line  
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1 execute on the Company's plans established in the Distribution Grid Plan ("DGP")<sup>4</sup>  
2 as discussed by Company Witness Chiu, which include a variety of initiatives to  
3 improve grid reliability. They are needed to support significant planned automation  
4 efforts, including incorporation of new smart devices and work on the Fault  
5 Location, Isolation and Service Restoration ("FLISR") project. Additional  
6 engineering staff also serve an important role in incorporating a variety of Outage  
7 Management System ("OMS") accuracy improvements, as well as reliability  
8 upgrades targeting data integrity and process-oriented enhancements. The  
9 Company is planning for increasing forecasted distributed energy resources  
10 ("DERs") interconnection volumes, which will require additional workforce and  
11 engineering expertise to accommodate. Through normal attrition, the departure of  
12 key engineering personnel and subject matter experts has created critical resource  
13 gaps that must be addressed. Without additional in-house engineering expertise, the  
14 Company risks delays in project execution, inefficiencies in system upgrades, and  
15 challenges in maintaining long-term reliability goals and improvements. Expanding  
16 the engineering workforce is essential to successfully navigating these operational  
17 demands while providing for the transfer and retention of critical technical  
18 knowledge.

19  
20 The Company's distribution system will undergo a significant transformation in the  
21 coming years, and the Company must be prepared to both execute these changes  
22 and operate under a modernized system. The Company is and will continue to  
23 actively expand its engineering personnel over the bridge and test years to meet the  
24 growing engineering demands and to enhance operational capabilities. The

---

<sup>4</sup> Exhibit A-23, Schedule M8

Line  
No.

1 expenses will fund incremental in-house engineering personnel. The Company  
2 plans to begin spending additional O&M in 2025 to cover the initial hiring needs  
3 and will utilize the \$8.3 million requested to support the personnel needed for  
4 business activities in 2026.

5  
6 In addition to in-house engineering staff, the Company is currently optimizing the  
7 engineering workforce by expanding partnerships with engineering and design  
8 firms to handle detailed design work. These partnerships utilize contracting  
9 models, like engineering, procurement, and construction agreements, to increase  
10 capacity and work volume, while adding flexibility as specific engineering needs  
11 change over time. While external engineering services are an effective supplement  
12 to the Company's workforce, the Company's engineers are needed to provide  
13 critical oversight to ensure quality and cost-effective project development. By  
14 increasing the overall engineering workforce, the Company will improve project  
15 efficiency and support the long-term reliability goals discussed by Witness Chiu,  
16 while ensuring critical engineering, technical and Company knowledge and skills  
17 are maintained as well as transferred to new team members.

18  
19 **Q25. What were the Audit's recommendations regarding engineering personnel?**

20 A25. The Audit highlighted on page 15 (Part Two) that more engineering resources than  
21 are currently available would be required for the Company to reach its reliability  
22 targets. Specifically, the Audit states that "DTE appears to require significantly  
23 more engineering personnel." The Audit goes further to note, "the inability to  
24 provide them not only risks significant delay in program execution, but in

Line  
No.

1 effectiveness and efficiency if engineering and design do not produce necessary  
2 support to meet expectations that form the basis for committing field resources.”

3

4 **Q26. Does the Company agree with the Audit recommendation?**

5 A26. Yes. The Company agrees with the recommendation and as noted above plans to  
6 increase the engineering and support personnel to address the concerns noted in the  
7 Audit.

8

9 **Q27. Finally, turning to O&M expenses related to non-discretionary corporate**  
10 **memberships, can you respond to the Commission’s directive in Case U-**  
11 **21534<sup>5</sup> to address these memberships and explain specifically why**  
12 **participation in the North American Electric Reliability Corporation**  
13 **(“NERC”) is important for the Company and its customers?**

14 A27. Participation in NERC is essential to maintaining compliance with mandatory  
15 reliability standards and maintaining a safe, reliable grid. As a NERC-registered  
16 entity, the Company must adhere to evolving reliability requirements and actively  
17 engages in shaping standards to support grid stability and the integration of new  
18 energy resources.

19

20 **Q28. Can you describe some of the benefits the Company and its customers realize**  
21 **through its memberships in required industry associations, such as NERC?**

22 A28. As discussed further by Witness Leslie<sup>6</sup> and recommended by the Commission in  
23 Order U-21534, NERC membership helps the Company remain compliant with  
24 mandatory reliability standards, directly supporting a stable and resilient grid for

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<sup>5</sup> Case No. U-21534, January 23, 2025 Order, page 466

<sup>6</sup> See Exhibit A-27, Sch. Q1.

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1 customers. Through NERC and regional entity ReliabilityFirst, the Company gains  
2 access to critical training, industry best practices, and regulatory updates. This helps  
3 improve system reliability, enhance outage response, and proactively address  
4 emerging challenges like integrating DERs. Ultimately, this membership enables  
5 the Company to deliver safer, more reliable, and cost-effective service to  
6 customers.

7  
8 **PART II: Global Prioritization Model**

9 **Q29. Can you summarize the Company's GPM framework and how the GPM**  
10 **framework supports the prioritization of DO capital strategic investments?**

11 A29. The GPM is a tool the Company's Distribution Operations team developed many  
12 years ago to prioritize investments. See Exhibit A- 23 Schedules M14 and M14.1.  
13 The GPM accomplishes this by developing a relative ranking based on the benefits  
14 the project or program delivers for a given level of investment. The ranking is  
15 accomplished through a process of an economic evaluation method, the "best-fit,  
16 most reasonable cost," to prioritize projects across eight impact dimensions that are  
17 aligned to the DTE Electric planning objectives, and develop a total project score  
18 based on the weighting of each impact dimension. Each of the eight impact  
19 dimensions within the GPM measures a benefit of the project or program. Projects  
20 delivering the most value across the eight impact dimensions are prioritized for  
21 earlier investment. The model results serve as the initial basis for the Company's  
22 investment prioritization and highlight those projects that have the highest relative  
23 benefit and/or are most urgent. In sum, the GPM helps the Company compare  
24 hundreds of vastly different types of projects and programs of different sizes and



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1 identify, within an analytical framework, which ones will be the most beneficial for  
2 customers.

3

4 **Q30. Does the GPM consider benefits and costs?**

5 A30. Yes. As I noted above, each of the eight impact dimensions within the GPM  
6 measures a benefit of the project or program. These benefits are weighed against  
7 costs in each of the dimensions. As I noted above, the GPM primarily provides a  
8 tool to prioritize the Company's investments. As Company Witness Chiu explains,  
9 however, the Company is continuing to refine its analysis of costs and benefits  
10 through an ongoing effort to incorporate greater benefit-cost analysis ("BCA"). In  
11 the context of the GPM, benefits are not converted to dollars, so a Benefit Cost  
12 Ratio ("BCR") is not generated as it would be with a full BCA.

13

14 **Q31. What was the Audit's assessment of the GPM?**

15 A31. Yes. The Audit discussed the significant progress of the GPM since its inception in  
16 2018.

17 Specifically, the Audit stated:

18 We found DTE's modeling used for evaluating, comparing, and prioritizing  
19 reliability initiatives, sound. DTE's Global Prioritization model, which  
20 systematically compares and evaluates competing system improvement and  
21 reliability-enhancing projects and programs across 10 important improvement  
22 dimensions, seems a balanced and logical application of the "best fit, most  
23 reasonable cost" economic approach to investment optimization. Its application at  
24 DTE is consistent with other utility strategic investment good practices that Liberty

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1 has experienced.<sup>7</sup> Additionally, it highlighted recent updates to the model, which  
2 included a new dimension that prioritizes projects benefiting vulnerable  
3 communities. The Audit also noted that the Company's has made strides in  
4 incorporating Environmental Justice into its distribution planning processes<sup>8</sup>.

5

6 **Q32. Did the Commission address the GPM in its 2024 Order?**

7 A32. In its Order dated January 23, 2025, in Case No. U-21534 the Commission found  
8 that the Company has responded to its directive for increased transparency  
9 regarding the foundation of the GPM and a clearer explanation of any deviations.<sup>9</sup>  
10 The Commission acknowledged the Company's efforts to provide a more  
11 comprehensive understanding of these aspects, noting that “[t]he Commission sees  
12 progress in the Company’s efforts at transparency in this case,”<sup>10</sup> and ultimately  
13 concluding that there was no need for the Company to implement extensive changes  
14 to its modeling processes.

15

16 **Q33. What determines whether a project is scored in the GPM?**

17 A33. The engineering team evaluates alternatives to meet system needs and selects the  
18 best project or program to move forward. If an investment is selected to move  
19 forward, it is scored in the GPM for prioritization.

20

21 **Q34. How does the GPM consider DTE Electric's planning objectives when**  
22 **evaluating the Company's distribution investments?**

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<sup>7</sup> Case No. U-21305; Part Two, Pages 24-25 (Conclusion No. 7)

<sup>8</sup> Case No. U-21305; Part Two, pg. 23

<sup>9</sup> Case No. U-21534 January 23, 2025 Order at 97.

<sup>10</sup> Case No. U-21534 January 23, 2025 Order at 97.

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A34. 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 outlined in the DGP<sup>11</sup>, which are: 1) Safety, 2) Reliability and Resiliency, 3) Affordability, 4) Clean Energy, and 5) Customer Accessibility and Community Focus. All impact dimensions measured in the GPM, as well as the new EJ Multiplier, are aligned to one or more of these five planning objectives as described in Table 1. 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.<sup>12</sup>

**Table 1 Mapping of GPM impact dimensions/multipliers to Planning Objectives**

|                      |                              | Planning Objectives |                        |            |       |                                         |
|----------------------|------------------------------|---------------------|------------------------|------------|-------|-----------------------------------------|
|                      |                              | Safe                | Reliable and Resilient | Affordable | Clean | Customer accessible and community focus |
| GPM Impact Dimension | Reduce Electrical Hazards    | ✓                   |                        | ✓          |       |                                         |
|                      | Overload Relief              | ✓                   | ✓                      | ✓          | ✓     | ✓                                       |
|                      | SAIDI                        | ✓                   | ✓                      | ✓          |       |                                         |
|                      | SAIFI                        |                     | ✓                      |            |       |                                         |
|                      | Major event risk             | ✓                   | ✓                      | ✓          |       |                                         |
|                      | Capacity Relief              |                     | ✓                      |            | ✓     | ✓                                       |
|                      | O&M Avoidance                |                     |                        | ✓          |       |                                         |
|                      | Capital Avoidance            |                     |                        | ✓          |       |                                         |
|                      | GPM Multiplier:              |                     |                        |            |       |                                         |
|                      | Investment In EJ Communities |                     |                        |            |       | ✓                                       |

Q35. Has the Company made any changes to the GPM framework that are included in this case?

<sup>11</sup> Exhibit A-23, Schedule M8, pg 17-19

<sup>12</sup> 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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1 A35. Yes, although the Company believes that the GPM was a robust planning tool in its  
2 previous form, the Company is continually reviewing and optimizing its investment  
3 analytics in support of customers. In that light, the Company has decided to  
4 implement three changes to the GPM to enhance its effectiveness.

5  
6 The first change is to remove the Regulatory Compliance dimension. After  
7 evaluation, while this dimension provided some value in the past, the Company  
8 determined that this dimension does not add enough meaningful value to the overall  
9 grid planning objectives to justify its continued use. In previous versions of the  
10 GPM, the Regulatory Compliance dimension only applied to two programs, PTMM  
11 and Frequent Outage, therefore this dimension was not helping to meaningfully  
12 rank and prioritize projects.

13  
14 The second change is within the safety dimension. The previous versions of the  
15 GPM had two components of safety: wire downs and manhole incidents due to  
16 failure of secondary cables. There were limited number of projects and programs  
17 addressing secondary cable failures, namely CODI projects and the program  
18 primarily driven by this dimension —Secondary Cable Replacements. This  
19 program will conclude by the end of 2026 once the butyl rubber cable risk has been  
20 eliminated. Therefore, going forward, the Reduce Electrical Hazards score for  
21 projects and program's will be based only on the reduction of wire downs alone.<sup>13</sup>

22  
23 The third change is to transform the EJ dimension into an EJ multiplier to focus the  
24 EJ impact on projects with benefits to vulnerable communities. The Company

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<sup>13</sup> For consistency of scoring year over year, six projects with secondary cable removal benefits and the Secondary Cable replacement program will receive a safety score based on the prior version of the GPM

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1 firmly believes that EJ is a factor that should be considered as part of the GPM  
2 analysis. The EJ dimension's primary value was to identify whether customers in  
3 vulnerable census tracts were positively impacted by a particular project. This was  
4 qualitatively different than the other eight dimensions of the model that quantify a  
5 project's system benefits. The EJ dimension was focused on where projects were  
6 located rather than on which projects would improve the system. In the previous  
7 version of the GPM, having the EJ score as a dimension resulted in projects that  
8 received higher scores and rankings based solely on a high EJ dimension score  
9 regardless of whether a project delivered any substantial system benefits.  
10 Theoretically, a project that demonstrated zero system benefits on the other  
11 dimensions but was located in an area with 100% vulnerable customers, could score  
12 200 in the previous GPM and could rank higher than a project that delivered system  
13 benefits but was not located in an EJ area. The new EJ multiplier allows projects  
14 with known benefits in EJ communities to be recognized and valued. This change  
15 will ensure that projects selected by the model are demonstrating customer benefits,  
16 and within that group of projects, the prioritization will favor those that have  
17 positive impacts on EJ communities.

18

19 **Q36. How does the new EJ multiplier work?**

20 A36. The EJ multiplier can range from 1.0 to 2.0 depending on the percentage of  
21 vulnerable customers impacted by the particular project or program. For example,  
22 if 80% of the customers affected by a circuit conversion project live in a vulnerable  
23 census tract, then the EJ multiplier would be 1.8 (number of vulnerable customers  
24 divided by total customers impacted by a project or program). The multiplier will  
25 increase the GPM score (the sum of the eight dimensions). As an example, if the

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1 GPM score is 100, using the example multiplier above, the final GPM score post  
2 multiplier would be 180. As a specific example in this case, the CODI: Kent/Gibson  
3 Conversion project has a score across the eight impact dimensions of 147. As 94%  
4 of the customers benefiting from this project live in vulnerable census tracts, the EJ  
5 multiplier is 1.94 and the final score is 285.

6

7 **Q37. How does the impact of the new EJ multiplier within the GPM compare to the**  
8 **previous version of the GPM where EJ was a dimension?**

9 A37. In the GPM that was submitted as part of Case No. U-21534, the EJ dimension  
10 accounted for 18% of all GPM points. With the updated multiplier approximately  
11 30% of the total points are a result of the EJ multiplier. However, with the  
12 implementation of the new multiplier, the Company has enhanced the GPM so that  
13 more of the EJ related points go to the programs or projects with the most impactful  
14 benefits in vulnerable communities and results in a higher likelihood that these  
15 projects will be selected for funding.

16

17 **Q38. Can you provide the full list of dimensions and associated weightings under**  
18 **the GPM as used in this case**

19 A38. See Table 2 below.

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**Table 2 Global Prioritization Model Impact Dimensions/Multiplier**

| Impact Dimension             | Drivers                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                    | Weight |
|------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|--------|
| Reduce Electrical Hazards    | <ul style="list-style-type: none"><li>Reduction in wire down events</li></ul>                                                                                                                                                                                                                                                                                                                                                                                                                                                              | 3      |
| Overload Relief              | <ul style="list-style-type: none"><li>Elimination of overloaded equipment</li></ul>                                                                                                                                                                                                                                                                                                                                                                                                                                                        |        |
| SAIDI                        | <ul style="list-style-type: none"><li>Reduction in duration of outage events</li></ul>                                                                                                                                                                                                                                                                                                                                                                                                                                                     |        |
| SAIFI                        | <ul style="list-style-type: none"><li>Reduction in frequency of outage events</li></ul>                                                                                                                                                                                                                                                                                                                                                                                                                                                    |        |
| Major Event Risk             | <ul style="list-style-type: none"><li>Reduction in extensive substation outage events that lead to a large amount of stranded load for more than 24 hours</li></ul>                                                                                                                                                                                                                                                                                                                                                                        | 2      |
| Capacity Relief              | <ul style="list-style-type: none"><li>Elimination of system capacity constraints</li></ul>                                                                                                                                                                                                                                                                                                                                                                                                                                                 | 1      |
| O&M Avoidance                | <ul style="list-style-type: none"><li>Trouble event reduction and truck roll reduction</li><li>Preventive maintenance investment reduction</li></ul>                                                                                                                                                                                                                                                                                                                                                                                       |        |
| Capital Avoidance            | <ul style="list-style-type: none"><li>Trouble event reduction and truck roll reduction</li><li>Reduction in capital replacement either during equipment failures or avoided planned capital work</li></ul>                                                                                                                                                                                                                                                                                                                                 |        |
| Multiplying Factor           |                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                            |        |
| Investment in EJ Communities | <ul style="list-style-type: none"><li>100% plus the percent of customers impacted by investment in EJ communities, such that the multiplication factor is 100% (or 1.0) if none of the customers impacted by a project live in vulnerable census tracts, and 200% (or 2.0) of all the customers impacted by a project live in vulnerable census tracks</li><li>The initial total GPM score (sum of the other eight impact dimensions) is multiplied by the EJ factor (which ranges from 1.0 to 2.0) to provide a final GPM score</li></ul> |        |

2

3 **Q39. How are projects and programs ranked using the GPM?**

4 A39. Strategic investments are assessed, scored, and then ranked in a quantitative manner  
5 on how they support and/or improve each impact dimension. Table 3 shows the  
6 mapping of the investments to the impact dimensions in which they generally  
7 receive a score based on the benefits the investment delivers.

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No.1     **Table 3            Selected programs and GPM impact dimensions/multiplier**

| Program                  | GPM Dimensions            |                 |       |       |                  |                 |               |                   | GPM mult.                    |
|--------------------------|---------------------------|-----------------|-------|-------|------------------|-----------------|---------------|-------------------|------------------------------|
|                          | Reduce Electrical Hazards | Overload Relief | SAIDI | SAIFI | Major Event Risk | Capacity Relief | O&M Avoidance | Capital Avoidance | Investment in EJ Communities |
| Substation Risk          |                           |                 |       |       | X                |                 |               |                   | *                            |
| 4.8kV Hardening          | X                         |                 | X     | X     |                  |                 | X             | X                 | X                            |
| PTMM                     | X                         |                 | X     | X     |                  |                 | X             | X                 | P                            |
| Cable Replacement        |                           |                 |       |       | X                |                 |               | X                 | P                            |
| Frequent Outage          |                           |                 | X     | X     |                  |                 |               |                   | P                            |
| Breaker Replacement      |                           |                 | X     | X     | X                |                 | X             | X                 | P                            |
| URD Replacement          |                           |                 | X     | X     |                  |                 |               | X                 | P                            |
| 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

2

3            Detailed analyses based on historical data, engineering assessments, and field  
4            feedback was used to quantify each investment's benefits within each impact  
5            dimension. The quantified benefits were then compared to the investment's costs  
6            to derive benefit-cost<sup>14</sup> ratios used to determine the relative difference between  
7            projects.

8

9            Unit measurements used for the benefit-cost ratios differ for each impact  
10           dimension. For example, reliability benefits are captured in customer minutes of  
11           interruption reduction whereas O&M and reactive capital benefits are captured in  
12           dollars avoided.

<sup>14</sup> As noted above the GPM does not convert all benefits to dollars as is done in traditional BCAs.



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1 Each program's benefit-cost score for each impact dimension is indexed so that a  
2 project with a benefit-cost ratio at the 95<sup>th</sup> percentile receives a score of 100.  
3 Projects scoring exceptionally high, above the 95<sup>th</sup> percentile, will receive a score  
4 above 100. This method provides three benefits. First, by aligning the 95<sup>th</sup>  
5 percentile to a score of 100, outlier projects do not skew the entire index. Second,  
6 the 100-point scale makes it easy to understand which projects are delivering the  
7 highest benefit per dollar invested – namely, the ones which score closer to 100.  
8 Finally, indexing, along with the weighting of dimensions, allows for the  
9 consideration of multiple monetary and non-monetary benefits to be combined into  
10 a single analysis.

11

12 Dimensions which align with core safety and reliability improvements, such as  
13 Reduce Electric Hazards, one of the Company's most important impact dimensions,  
14 is given the highest weight of 3. This effectively means that a score of 100 in a  
15 lower weighted dimension will not be worth as much as a 100 rating in Reduce  
16 Electrical Hazards, the highest weight. For example, if a project's Reduce  
17 Electrical Hazards score is 50 (on a 0-100 scale), it will be multiplied by a weighting  
18 factor of 3 to receive a score of 150. A project with a Capacity Expansion score of  
19 50 will be multiplied by the weighting of 2 and contribute 100 to the total scoring.  
20 This example illustrates how the impact dimension weights will rank projects  
21 higher if they provide benefits in dimensions with higher weightings. Once a  
22 program's index scores have been calculated across all impact dimensions and  
23 adjusted by weight, the index scores are summed together to determine the  
24 program's overall score. The higher the score, the better the GPM ranking.

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1 **Q40. How do the GPM results support the Company's distribution investment**  
2 **decisions?**

3 A40. The Company uses the GPM to select the highest relative benefit projects that will  
4 have the greatest impact improving the grid and the overall customer experience.  
5 Projects and programs are analyzed and ranked using the GPM on an annual basis.  
6 Investments that score highest in the GPM rankings are the ones that are generally  
7 selected for the Company's distribution infrastructure strategic investment plan. As  
8 described in detail below, there are some projects that are chosen outside of the  
9 GPM process or lower ranked projects within the process that are funded for various  
10 specific operational reasons.

11  
12 Projects and programs that span multiple years are evaluated every year and may  
13 experience a change in GPM ranking if additional information modifies the  
14 expected project costs or benefits. However, to keep scoring relatively consistent  
15 year over year, the entire project cost as well as project benefits are still used when  
16 scoring the project or program, although the project costs and benefits will be  
17 adjusted for known changes (examples include costs changes, or increased  
18 benefits).

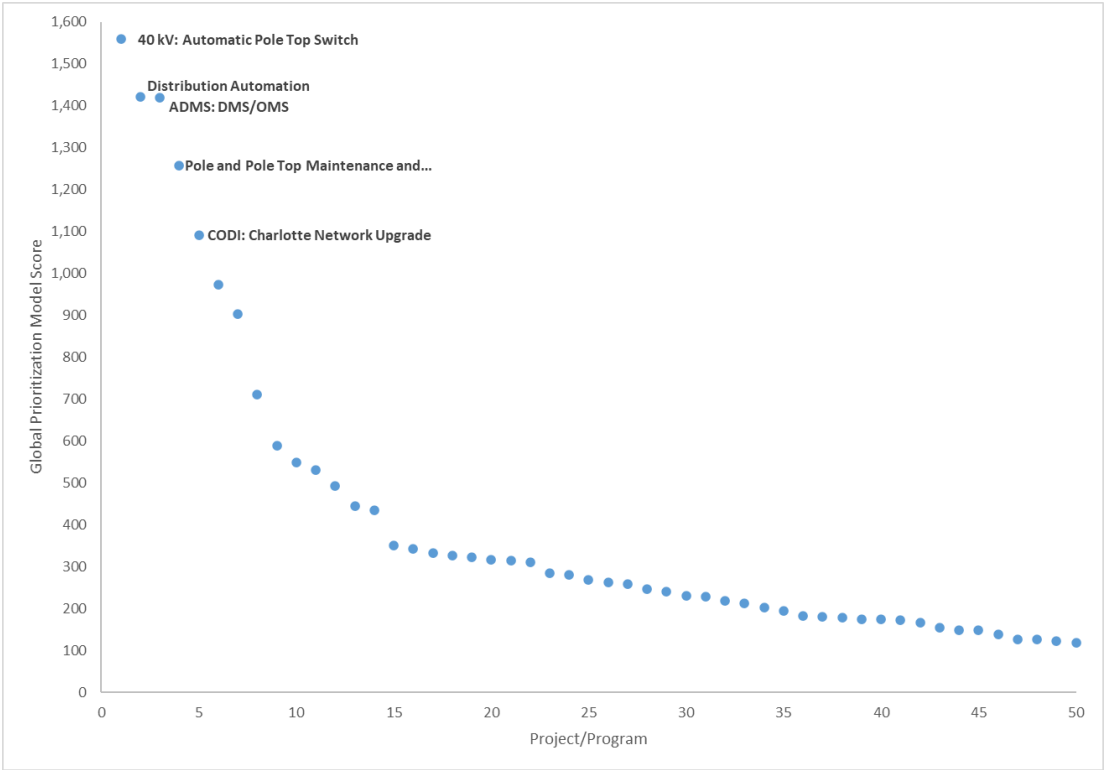
19  
20 **Q41. What are the GPM scores for the projects and programs proposed in this case?**

21 A41. The total GPM scores for strategic capital projects and programs, ranked from  
22 highest to lowest, are illustrated in Figure 1. In addition, Table 4 lists the names of  
23 the top 50 capital projects and programs. GPM scores for the top 50 projects and  
24 programs, including scores for each of the 8 impact dimensions, are included in  
25 Exhibit A-23 M14 GPM Project and Program Rankings.

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**Figure 1. Overall GPM Scores for top 50 strategic capital programs and projects**



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**Table 4 Top 50 Strategic Capital Programs and Projects Based on GPM**

| Rank | Capital Program/Project                                          | Rank | Capital Program/Project                                  |
|------|------------------------------------------------------------------|------|----------------------------------------------------------|
| 1    | 40 kV: Automatic Pole Top Switch                                 | 26   | Small Wire Replacement Program                           |
| 2    | Distribution Automation                                          | 27   | Subtransmission Redesign & Rebuild: Tie 6907             |
| 3    | ADMS: DMS/QMS                                                    | 28   | 4.8 kV CC: Hilton Substation and Circuit Conversion      |
| 4    | Pole and Pole Top Maintenance and Modernization (PTMM)           | 29   | Subtransmission Redesign & Rebuild: Trunk 4217           |
| 5    | CODI: Charlotte Network Upgrade                                  | 30   | Subtransmission Redesign & Rebuild: Trunk 7333           |
| 6    | 4.8 kV CC: Hawthorne Relief and Circuit Conversion               | 31   | 4.8kV CC: SCOTN                                          |
| 7    | 4.8 kV Hardening                                                 | 32   | URD Replacement Program                                  |
| 8    | 4.8 kV CC: Grosse Pointe Substation and Circuit Conversion South | 33   | Substation Risk: Chestnut                                |
| 9    | 8.3 kV CC: Pontiac Overhead/Underground Conversion               | 34   | Cable Replacement Program                                |
| 10   | Subtransmission Redesign & Rebuild: Tie 1568                     | 35   | NWA: Port Austin Load Relief                             |
| 11   | Subtransmission Redesign & Rebuild: Trunk 2237-ST                | 36   | Subtransmission Redesign & Rebuild: Bernard              |
| 12   | CODI: Garfield Network Upgrade                                   | 37   | CODI: Corktown Substation                                |
| 13   | CODI: Targeted Network Secondary Cable Replacement               | 38   | Subtransmission Redesign & Rebuild: Trunk 7105           |
| 14   | Frequent Outage Program (CEMI)                                   | 39   | 4.8kV CC: Hemlock Decommissioning and Circuit Conversion |
| 15   | 4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade)    | 40   | Breaker Replacement Program                              |
| 16   | CODI: Howard Conversion                                          | 41   | Distribution Sensing and Monitoring (inclg Line Sensors) |
| 17   | 4.8 kV CC: Zenon Circuit Conversion Phase 2                      | 42   | Substation Risk: Savage Switchgear Replacement           |
| 18   | 4.8 kV CC: McKinstry Sub Decommission                            | 43   | Subtransmission Redesign & Rebuild - Trunk 2448          |
| 19   | 4.8 kV CC: Birmingham Decommissioning and Circuit Conversion     | 44   | 4.8 kV CC: New Baltimore                                 |
| 20   | Subtransmission Redesign & Rebuild: Trunk 7106                   | 45   | Subtransmission Redesign & Rebuild: Trunk 1444           |
| 21   | 4.8 kV CC: ISO Conversion Program                                | 46   | Subtransmission Redesign & Rebuild: Trunk 0359           |
| 22   | Subtransmission Redesign & Rebuild: Trunk 2255                   | 47   | Station Upgrade: Warren (Relay Replacement)              |
| 23   | CODI: Kent/Gibson Conversion                                     | 48   | 4.8 kV CC: Belleville Substation and Circuit Conversion  |
| 24   | 4.8 kV CC: Buckler Circuit Conversion                            | 49   | 4.8kV CC: Pittsfield Substation and Circuit Conversion   |
| 25   | CODI: Islandview Substation                                      | 50   | Subtransmission Redesign & Rebuild: Hurst                |

3

4 **Q42. Are there other factors besides the GPM ranking that could impact the final**  
5 **project and program selection and timing?**

6 A42. Yes. While the benefit-cost scores of programs and projects and their prioritization  
7 ranking provide the foundation for the Company's strategic investment decisions,  
8 there are other considerations that could impact project selection and timing, as  
9 listed below:

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- 1 • Investment timing for programs and projects considers the impact on  
2 workforce needs. Resources required for engineering, design, project  
3 management, scheduling, and construction need to be evaluated not only by  
4 project type (substation, overhead or underground) but also by geographic  
5 location. Resource gaps and balancing are evaluated before project  
6 sequencing decisions are made. Investment decisions also consider the  
7 Company's capacity to perform the work, as the Company often partners  
8 with third parties to plan and execute projects as noted above in Part I.
- 9 • System operational constraints and stability, occasionally including  
10 transmission, can cause the Company to adjust the timing of a project. For  
11 example, a project may be needed to address subtransmission system  
12 integrity caused by load growth.
- 13 • Regulatory requirements or guidance also influence the selection of some  
14 projects and programs. NERC requirements, for example, require system  
15 upgrades to ensure the bulk electric system is unaffected by subtransmission  
16 outages. These NERC-driven projects have benefits that are difficult to  
17 quantify in GPM.
- 18 • Safety issues that cannot be easily quantified and indexed could warrant an  
19 investment regardless of the scoring within the GPM model to protect our  
20 customers or employees. For instance, subtransmission disconnect switches  
21 and the Pontiac vault projects are necessary to meet operational safety  
22 needs.
- 23 • Pilot projects may be pursued independently of how they score and rank in  
24 the GPM as they are used to determine what the expected benefits and cost  
25 may be to complete an activity that the Company believes could be

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1           beneficial to its customers. In other words, the pilots help provide the data  
2           for a more adequate accounting of potential future project benefits. An  
3           example is non-wire alternative (“NWA”) projects. These NWA pilot  
4           projects focus on using alternative technologies to address circuit or  
5           substation overload concerns to help delay or offset traditional grid  
6           upgrades. These pilots are supported by Company Witness Rademacher  
7           and detail is provided in Exhibit A-12 Schedule B5.4.1 through B5.4.7.  
8           Future pilots would be considered through the Commission’s expedited  
9           pilot process.

10           •     Capital projects are subject to certain development and execution risks in  
11           the conceptual design and early development stages, including land  
12           availability and property purchases, municipal approvals and construction  
13           permits, right-of-way acquisition and easements, and lead times when  
14           procuring major equipment. While the Company takes proactive measures  
15           to mitigate these execution risks, many of these early-stage developments  
16           are difficult for the Company to control and can introduce schedule delays  
17           or cost increases. Therefore, the Company’s investment and maintenance  
18           plan is designed to include some flexibility to accommodate these  
19           unpredictable variations in timing and cost.

20           •     Some capital replacement programs are funded annually to avoid  
21           acceleration of asset failures and the risk that a large quantity of assets  
22           would reach end-of-life concurrently, thus exceeding available resources to  
23           replace them (e.g., the underground residential distribution cable program).

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- 1 • If the Company is awarded grant money from the state or federal
- 2 government for specific projects, it could impact project selection due to
- 3 grant project completion requirements.
- 4 • Projects already in active construction are prioritized.
- 5 • Some Operational Technology (“OT”) projects are not evaluated through
- 6 the GPM, as the GPM is largely designed for investments which upgrade
- 7 the physical distribution grid. The specific benefits which OT projects
- 8 deliver are discussed in more detail in Witness Rademacher’s testimony.

9

10 It is important to note that some programs and projects may not be funded in a  
11 particular year due to lower benefit-cost scores relative to other projects. All the  
12 programs and projects identified by the Company and evaluated by the GPM  
13 provide system improvements and benefits to customers and may be funded at some  
14 point over the next several years. While the strategic capital investment plan is  
15 primarily driven by the GPM, the Company may adjust the annual plans based on  
16 changing circumstances and grid needs.

17

18 **Q43. Do the GPM scores and rankings have the potential to change over time?**

19 A43. Yes. As the Company continues to make investments in distribution infrastructure,  
20 the benefits of capital investment are examined on a regular basis and the GPM  
21 scores may change over time as new data becomes available, and the prioritization  
22 ranking of the programs and projects may change accordingly. As the Commission  
23 acknowledged in its 2024 Order, the Company’s top 50 list and the associated cost  
24 estimates are not static.<sup>15</sup>

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<sup>15</sup> Case No. U-21534 January 23, 2025 Order at 97

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**PART III: Reliability Model**

**Q44. Please describe the Company's Reliability Model.**

A44. The Reliability Model is an analytical tool that estimates tangible reliability improvements associated with proposed capital investments in a data-driven framework and on a circuit-by-circuit basis. See Exhibit A-23 Schedule M12. The model calculates improvements from investment programs and projects on the basis of industry-standard performance metrics and includes an adjustment for post-investment degradation over time, providing a way to numerically estimate the reliability benefits that the proposed projects will provide. Alongside the GPM and BCA tools, the Reliability Model is an important vehicle for evaluating and ranking capital investments so that the Company is delivering maximum value and impact for customers.

**Q45. How does the Company calculate reliability improvement projections?**

A45. The reliability calculations are performed at a circuit level based on historical performance and the estimated impact of planned investments on those circuits. The projected performance of all circuits with program investment is then summed to provide a system level projection. The process to project reliability performance within the model can be summarized in five steps:

1. **Baseline:** Calculate circuit-level baseline reliability performance.
2. **Program effectiveness:** Estimate impact the modelled reliability programs would have if a circuit undergoes an investment, generally calculated as a percent reduction in event volume or a reduction in customer interruptions and customer minutes per event.
3. **Degradation impact:** Estimate impact of system degradation over time.



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1                   4. **Investment plan:** Enter planned or expected in-service schedule for  
2                   reliability programs into model.

3                   5. **Calculate performance with major event days excluded (“Ex-MED”):**  
4                   Combine baseline performance with investment plan and effectiveness of  
5                   the investments on a circuit level to project future performance.

6                   6. **Calculate All-weather performance:** Scale Ex-MED output to all  
7                   weather output and expected ranges

8                   Each of these steps is described briefly below.

9

10 **Q46. How is the starting point, or circuit baseline calculated?**

11 A46. Each circuit has a baseline of reliability performance based on 2018-2022, non-  
12 MED event volume. Events are further divided into tree and non-tree, single and  
13 multiple, and outage and non-outage caused events. An average customers  
14 interrupted (“CI”) and customer minutes interrupted (“CMI”) per event is used to  
15 convert the volume of events to a SAIDI Ex-MED and SAIFI ex-MED baseline.

16

17 **Q47. Which reliability investments are included in the model?**

18 A47. The model’s purpose is to forecast system reliability and investment impact based  
19 on outage events on the overhead distribution system (where the vast majority of  
20 the Company’s outage events occur) as well as the impact of projects and programs  
21 which have the potential to reduce the impact of overhead outage events. The  
22 model accounts for reliability improvements from six large investment programs:  
23 Tree Trimming, 4.8kV Hardening, PTMM (both pole work and pole-top work),  
24 Customer Excellence, 4.8kV Conversion, and Automation.

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1   **Q48. How does the Company estimate the effectiveness of the reliability**  
2       **investments?**

3   A48. Of the six large investment programs included in the reliability model, four utilize  
4       historical data to evaluate effectiveness. These programs are Tree Trimming, 4.8kV  
5       Hardening, PTMM, and Customer Excellence. The method to establish  
6       effectiveness begins by setting a baseline of non-MED circuit performance for  
7       years prior to the reliability improvement being deployed. Non-MED event data  
8       for years post deployment is compared to the baseline to calculate the reliability  
9       improvement. The year the investment is made is not used in the effectiveness  
10      analysis as the timing of the work being completed could impact in-year  
11      performance. For example, if PTMM is performed in January, reliability  
12      improvement would be expected for most of the year. If it were performed in  
13      December, little improvement would be expected that year. For the Automation and  
14      4.8kV Conversions Programs, the reliability improvement is based either on the  
15      assessment from industry subject matter experts, including DTE Electric's  
16      Engineering, by comparing the newer program to similar established programs, or  
17      by using a smaller subset of circuit outage data.

18

19      In the model, investments reduce the type of event that is likely to be influenced by  
20      that investment. For example, if a circuit has tree trimming planned, the model will  
21      project a reduction in tree-related multiple events.

22

23   **Q49. Have the effectiveness analyses utilized in the Reliability Model been updated**  
24       **since case U-21534?**

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1 A49. Yes, the effectiveness analyses presented in Exhibit A-23 Schedule M12 have been  
2 updated in three ways compared to what was used in Case No. U-21534. The first  
3 update is that they are based on the 12-month calendar year data, an update from  
4 the 10-month data that was used in Case No. U-21534. The second update is that  
5 actual reliability performance from 2023 and 2024 is incorporated into the analysis.  
6 Finally, the reliability performance during the year in which the investment made  
7 is excluded from the analysis, as described in the question above.

8

9 **Q50. How is future circuit performance projected?**

10 A50. The proposed investment plan by program and project is entered into the model on  
11 a circuit level basis. For example, the model has a list of circuits with planned  
12 PTMM in 2025 that aligned with the Company's investment plan. Circuits which  
13 have Tree Trimming, 4.8kV Conversion, 4.8kV Hardening, or PTMM work will  
14 have the program benefits applied to them in the form of reducing the future volume  
15 of events. Half of the maximum benefit will be applied in the year of the  
16 investment, with the simple assumption that with some investments occurring early  
17 in the year and some later in the year, on average, projects will be constructed and  
18 useful for half of the year. The full benefit is then applied in the first year after the  
19 investment. The benefit will decrease over time due to factors such as the regrowth  
20 of trees, and the continued aging of overhead equipment. The model assumes that  
21 significant rebuild work provided by 4.8kV Conversion will deliver a consistent  
22 benefit for 10 years after the investment without any degradation. The impact of  
23 the Automation investment is a reduction in the CI per event on the circuit, but there  
24 is no associated reduction in event volume. If a circuit has no planned investment  
25 indicated in the model, the model will calculate an increase in future event volume,

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1 or degradation, over time. This is because the equipment on that circuit is assumed  
2 to degrade over time without inspection and periodic replacement.

3

4 **Q51. How are Ex-MED and All-Weather reliability projections calculated within**  
5 **the Reliability Model?**

6 A51. The primary output of the model is a projection of ex-MED event volume, which  
7 is translated into SAIFI ex-MED and SAIDI ex-MED using a historical event  
8 average CI and CMI per event. The ex-MED results are scaled to all-weather  
9 projections by calculating the ex-MED to all weather performance relationship of  
10 64 large utilities based on historical data available on EIA.gov. As an example, for  
11 utilities who had a SAIDI ex-MED of 100 minutes in a given year, the range of All-  
12 Weather SAIDI outcomes, excluding the top and bottom 20% of outcomes, was  
13 140 minutes to 342 minutes. If the model projects the Company's SAIDI ex-MED  
14 performance to be 100 minutes, it would also calculate a range of expected all-  
15 weather outcomes to be 140 to 342 minutes, with an average performance  
16 calculated as the median of the data set. This range, based on industry performance,  
17 accounts for weather variability.

18

19 **Q52. Do other programs not included in the Reliability Model have reliability**  
20 **benefits?**

21 A52. Yes. Other programs such as Subtransmission projects, URD Replacement, Cable  
22 Replacement, Breaker Replacement, Substation Risk projects, and Preventive  
23 Maintenance Programs will also reduce outage events and impact reliability. For  
24 specific benefits from these projects and programs, please refer to testimony from  
25 Witnesses Robinson, Stowe, and Rademacher.

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1 **Q53. Is the Company confident in the reliability improvement estimates?**

2 A53. Yes. First, the model is based on ex-MED events and reliability, which has less  
3 inherent variability than all-weather performance. Second, by modeling the system  
4 on a circuit level basis, this methodology accounts for benefits from separate  
5 programs on the same circuit without double counting. Finally, as circuit  
6 performance is disaggregated into many event types (tree vs. non tree, single vs.  
7 multiple, outage vs. non-outage), program improvements can more accurately be  
8 modeled against the events they are most likely to address.

9

10 **Q54. Does the reliability model project emergent cost reductions?**

11 A54. Yes. The Reliability Model projects emergent cost reduction, based on number of  
12 events reduced, which is shown in Exhibit A-12, Schedule B5.4, page 1, line 6.

13

14 **Q55. Is the Company incorporating any important changes to the Reliability Model**  
15 **as part of the instant case when compared to the model used in U-21534?**

16 A55. Yes. In addition to the updated effectiveness analysis discussed above, the  
17 Company has bifurcated PTMM in the model into pole work and pole-top work,  
18 with separate effectiveness, to align with how the PTMM work will be implemented  
19 performed. The model also updates how Customer Excellence benefits are  
20 calculated. Rather than applying Customer Excellence benefits to specific circuits,  
21 system level benefits are calculated based on historical performance and the  
22 projected volume of future work. This methodology was changed because  
23 Customer Excellence circuits are identified based on recent reliability performance,  
24 and are not selected more than a year in advance. The previous model only

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1 accounted for Customer Excellence benefits in one year (2024), even though the  
2 program will continue to address circuits in future years.

3

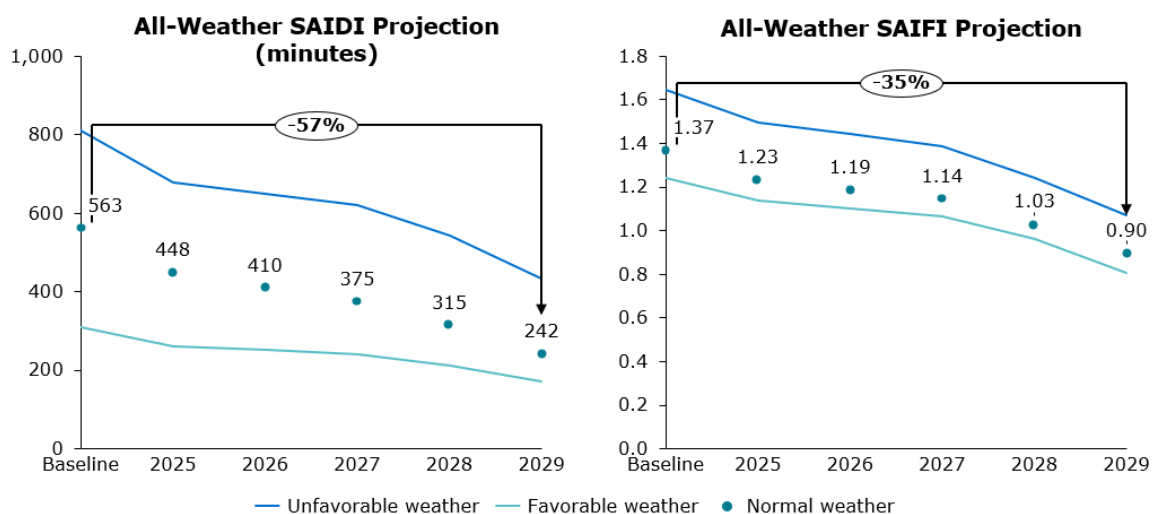
4 **Q56. Turning to the results of the model, based on DO investments proposed in this**  
5 **case, what system reliability improvements are expected?**

6 A56. The Company's Reliability Model projects that customers are expected to  
7 experience an all-weather SAIDI of 448 minutes in 2025 and 410 minutes in 2026  
8 versus a historical baseline of 563 minutes, assuming normal weather. Similarly,  
9 all-weather SAIFI will improve to 1.23 in 2025 and 1.19 in 2026 from the historical  
10 baseline of 1.37. Graphs of expected reliability improvements through 2029 are  
11 shown in Figure 2. As I discussed above, these estimates are conservative in that  
12 they do not include the improvement impact of all proposed investments.

13

14

**Figure 2. All-Weather Reliability Projections<sup>16</sup>**



<sup>16</sup> The baseline is the 2018-2022 five year average for All-Weather SAIDI and SAIFI

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1 **Q57. How did the Reliability Model prediction for 2024 from Case No. U-21534**  
2 **compare to actual performance?**

3 A57. The Reliability Model utilized in the previous case predicted an All-Weather SAIDI  
4 performance of 504, the Company's year-end performance was 483. SAIFI was  
5 predicted to be 1.30 in the model and actual performance was 1.25.

6

7 **PART IV: IIJA Grant Opportunities**

8 **Q58. What are IIJA grants?**

9 A58. The federal IIJA was enacted in November 2021. The goal of the IIJA grants is to  
10 provide funding opportunities in multiple types of investments to catalyze public  
11 and private investment to enhance the nation's infrastructure, with a particular  
12 focus on helping America's disadvantaged communities. For electric  
13 infrastructure, the grants are primarily administered in three broad categories:  
14 improving grid resilience, building smart grids, and pursuing grid innovation.

15

16 **Q59. Can you provide an overview of the Company's efforts in securing IIJA funds?**

17 A59. The Company aggressively pursued IIJA grant opportunities to fund reasonable  
18 investments at a reduced cost to customers. In October 2023, the Department of  
19 Energy ("DOE") notified the Company that its application for the Adaptive  
20 Networked Microgrid ("ANM") pilot program was successful. The Company was  
21 in the process of negotiating details of the ANM grant through January 2025. As  
22 described below, since that time, federal agencies, including the DOE, have paused  
23 all communications with external parties regarding IIJA grants, and the Company  
24 was unable to reach a final agreement prior to the halt in communication. The  
25 Company is awaiting further guidance regarding pending grant projects.

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1 **Q60. Will the Company continue to seek additional IIJA grant funding to invest in**  
2 **the distribution system in 2025?**

3 A60. As I noted above, the DOE has currently paused all federal grant negotiations. At  
4 this time, the Company has not been informed when, or if, such negotiations on  
5 previously awarded grants will continue, or if additional grants will be awarded.  
6 The Company also anticipates that, in the event grant negotiations and awards are  
7 resumed, there may be changes in project funding, scope, and oversight, which will  
8 likely further challenge the timing and progress of such grant projects, ultimately  
9 impacting the Company's customers. Consequently, the Company is suspending  
10 its efforts to secure federal grants and will develop future applications later if there  
11 is a change in status. No costs related to federal grants are included in this  
12 proceeding.

13

14 **PART V: Environmental Justice**

15 **Q61. How does the Company define environmental justice?**

16 A61. The Company defines EJ in the context of the State of Michigan's MiEJ Screening  
17 tool<sup>17</sup> definition of environmental justice as "the equitable treatment and  
18 meaningful involvement of all people, regardless of race, color, national origin,  
19 ability, or income in the development and application of laws, regulations, and  
20 policies that affect the environment, as well as the places people live, work, play,  
21 worship, and learn."<sup>18</sup>

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<sup>17</sup> MiEJScreen: Environmental Justice Screening Tool (michigan.gov) available at  
<https://www.michigan.gov/egle/maps-data/miejscreen?adlt=strict>.

<sup>18</sup> State of Michigan, Department of Environment, Great Lakes, and Energy,  
<https://www.michigan.gov/egle/public/learn/environmental-justice>, accessed March 18, 2025.



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1 **Q62. How did DTE Electric incorporate EJ in grid planning as described in the 2023**  
2 **DGP?**

3 A62. Building on the 2021 DGP, the Company developed three key EJ objectives for the  
4 2023 DGP; (1) incorporate EJ considerations in investment decisions by including  
5 an EJ component in the GPM, (2) improve system performance for vulnerable  
6 communities experiencing poor reliability through our investment programs, and  
7 (3) provide support to vulnerable customers experiencing outages during storms  
8 through community outreach efforts.

9

10 **Q63. Can you provide an overview of the findings of the Audit regarding the**  
11 **Company's efforts to incorporate EJ into its planning.**

12 A63. The Audit noted that the Company has made strides in integrating EJ into  
13 distribution planning and intends to continuing enhancing these efforts over time.  
14 The Audit stated that "the Company's ongoing plans to significantly invest in the  
15 hardening and replacement of aging 4.8kV infrastructure, while not targeted to  
16 Detroit's most vulnerable communities, will benefit electric reliability of those  
17 communities."<sup>19</sup>

18

19 **Q64. What were the Commission's findings in Case No. U-21534 related to EJ in the**  
20 **Company's system reliability and capital investment?**

21 A64. The Commission found that the Company illustrated reasonable and prudent EJ  
22 considerations, thus justifying its City of Detroit Infrastructure (CODI) spending as  
23 it also reviews multiple factors such as reliability and safety in addition to EJ to  
24 support its grid objectives for all customers. The Commission also found that the

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<sup>19</sup> Case No. U-21305; Part Two; Ch. 1; p. 23.

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1 Company's use of the MiEJScreen tool to be a reasonable starting point for equity-  
2 related analyses and acknowledged the Company's mapping of reliability  
3 investments to vulnerable communities, with significant investments in 4.8kV  
4 Hardening and 4.8kV Conversions. The Commission noted that it looks forward to  
5 the Company's continued work with interested persons to incorporate additional  
6 EJ-related considerations.<sup>20</sup>

7

8 **Q65. How has DTE Electric Distribution Operations defined a vulnerable**  
9 **community for use with the MiEJScreen Tool?**

10 A65. An 80% threshold definition was adopted for vulnerable communities using the  
11 MiEJScreen Tool score, consistent with the previously available U.S. EPA  
12 EJScreen tool.<sup>21</sup> Following this approach, census tracts with a MiEJScreen  
13 composite score at or above the 80<sup>th</sup> percentile are considered vulnerable  
14 communities for the purpose of this testimony and associated analysis. The  
15 MiEJScreen composite score is calculated using categories and indicators for  
16 environmental and census population data as shown in Figure 3 below. On  
17 November 18, 2022, the Commission directed its Energy Affordability and  
18 Accessibility Collaborative to address definitions of terms such as environmental  
19 justice, grid equity, and energy justice (Case No. U-20836, November 18, 2022  
20 Order, pp. 461-464).

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<sup>20</sup> Case No. U-21534 January 23, 2025 Order at 443-444.

<sup>21</sup> EPA, [EJScreen Technical Documentation for Version 2.3](#), accessed March 19, 2025.

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1

**Figure 3. MiEJScreen Overall Score Calculation**

| Categories | Environmental Exposure                                                                                                                                                    | Environmental Effects                                                                                                                                                                                                               | Sensitive Populations                                                                                                                                            | Socioeconomic Factors                                                                                                                                                                                          |
|------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Indicators | NATA Air Toxics Cancer Risk<br>NATA Respiratory Hazard Index<br>NATA Diesel Particulate Matter<br>Particulate Matter (PM <sub>2.5</sub> )<br>Ozone<br>Traffic Density     | Proximity to Cleanup Sites<br>Proximity to Hazardous Waste Facilities<br>Impaired Water Bodies<br>Proximity to Solid waste Sites and Facilities<br>Lead Paint Indicator<br>Proximity to RMP Sites<br>Wastewater Discharge Indicator | Asthma<br>Cardiovascular Disease<br>Low Birth Weight Infants<br>Blood Lead Level<br>Life Expectancy                                                              | Low Income Population<br>Black, Indigenous, People of Color Population<br>Educational Attainment<br>Linguistic Isolation<br>Population Under Age 5<br>Population Over Age 64<br>Unemployment<br>Housing Burden |
| Sub Scores | <b>Environmental Conditions</b><br>(Average percentile of Environmental Exposure indicators + 0.5 x average percentile of Environmental Effects indicators)<br><u>1.5</u> |                                                                                                                                                                                                                                     | <b>Population Characteristics</b><br>(Average percentile of Sensitive Population indicators + average percentile of Socioeconomic Factor indicators)<br><u>2</u> |                                                                                                                                                                                                                |
| Score      | Final Composite Score = Environmental Conditions score x Population Characteristics score<br><b>MiEJScreen Score</b>                                                      |                                                                                                                                                                                                                                     |                                                                                                                                                                  |                                                                                                                                                                                                                |

2

3 **Q66. Using available data, is the Company able to provide a geographic**  
 4 **representation of 2024 electric reliability data by census tracts?**

5 A66. Yes. Using the residential customer meters that are matched to census tracts, DTE  
 6 Electric developed reliability data for SAIFI and SAIDI by census tract and grouped  
 7 the data into DTE Electric reliability quartiles, with first quartile customers (shown  
 8 below in green) experiencing the best reliability and fourth quartile customers  
 9 (shown below in red) experiencing the worst reliability. Looking specifically at  
 10 outage frequency, first quartile reliability customers have a 2024 All-Weather  
 11 SAIFI performance of fewer than 0.48 interruptions, second quartile customers  
 12 range between 0.48 and 1.01 interruptions, third quartile customers are between  
 13 1.01 and 1.65 interruptions, and fourth quartile customers have performance greater

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1 than 1.65 interruptions. Looking at outage duration, first quartile reliability  
2 customers have a 2024 All-Weather SAIDI performance less than 96 minutes,  
3 second quartile customers range between 96 and 267 minutes, third quartile  
4 customers are between 267 minutes and 625 minutes, and fourth quartile customers  
5 have experienced outage duration above 625 minutes. Maps for SAIFI and SAIDI  
6 by census tract are included in Figure 4 to Figure 7.

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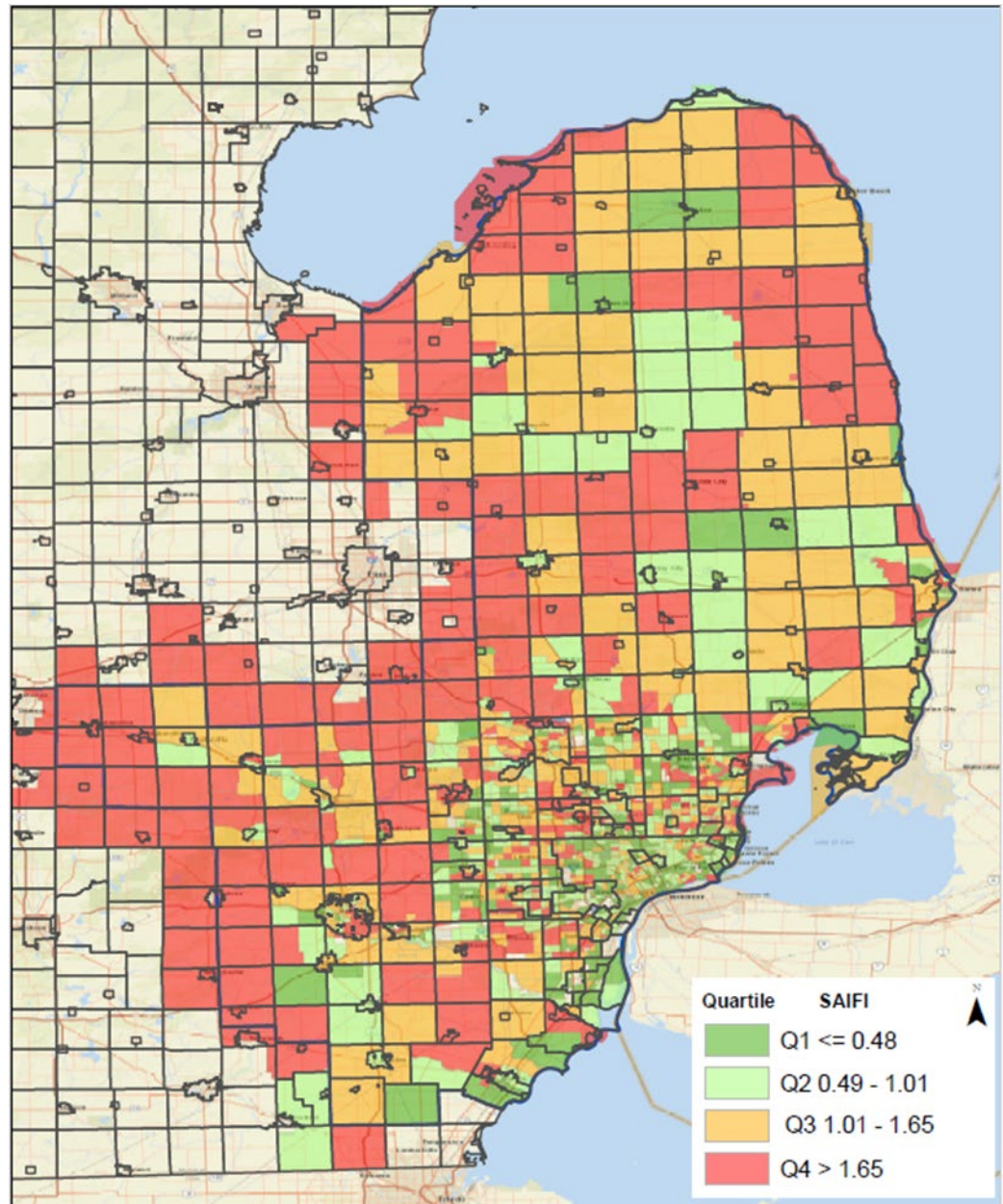
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**Figure 4. 2024 All Weather SAIFI by Census Tract for DTE Electric (Full**

2

**Electric Service Area)**

3

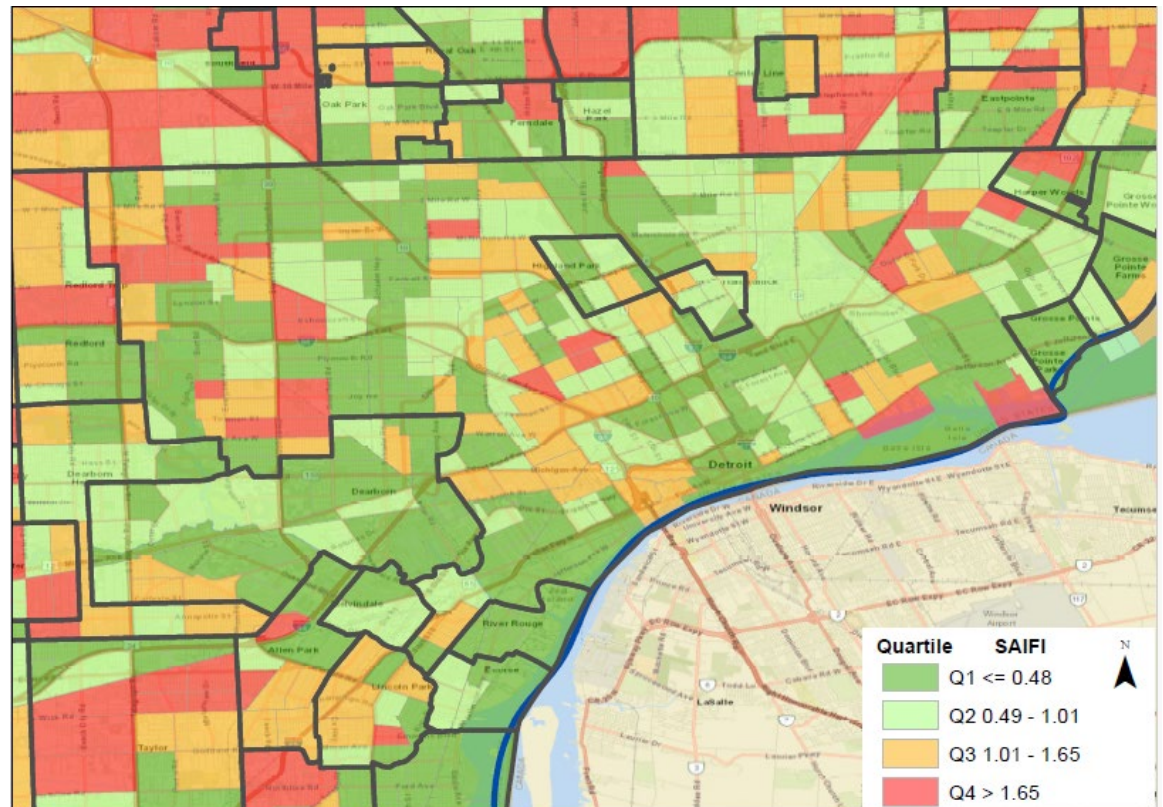




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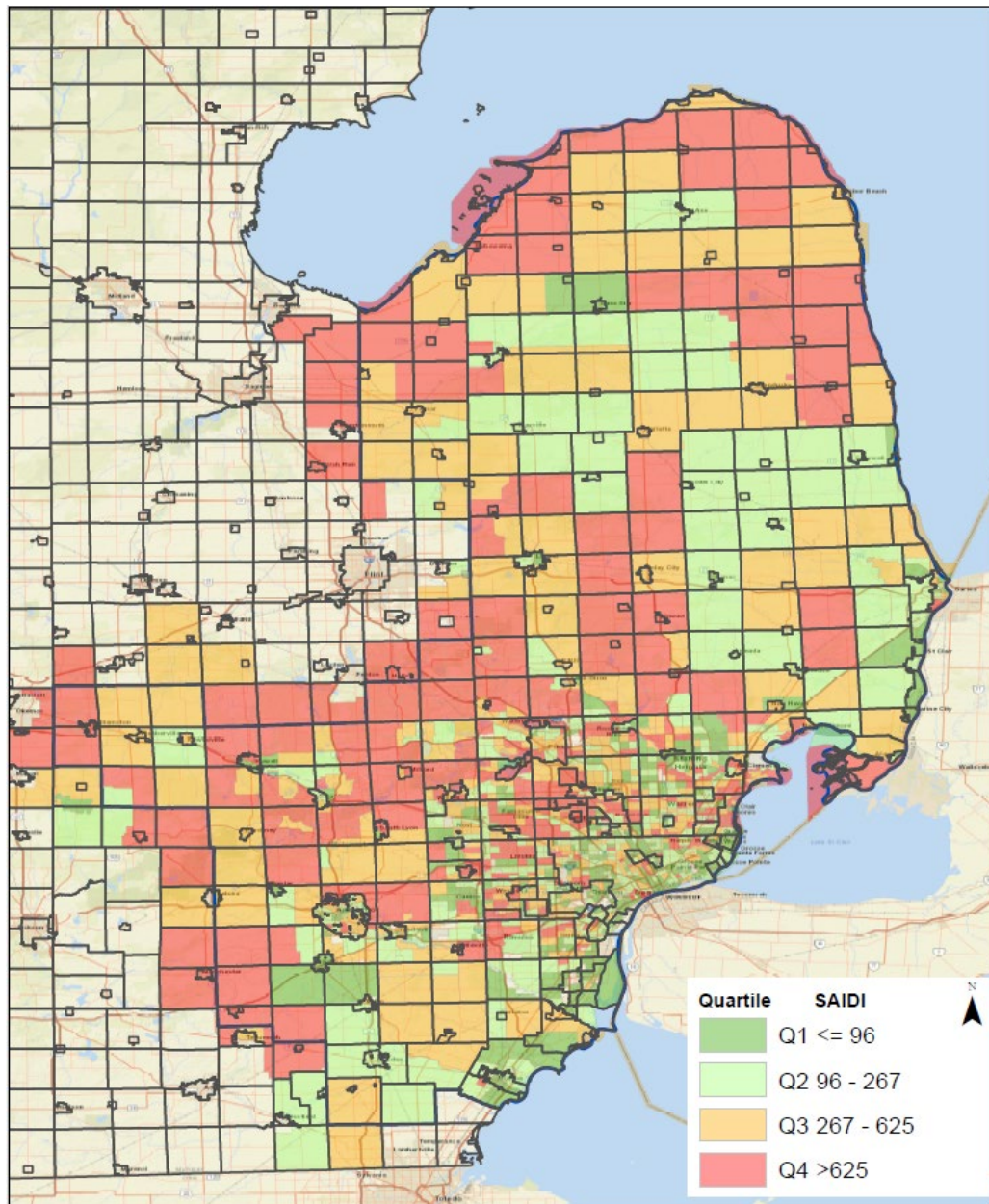
**Figure 5. 2024 All Weather SAIFI by Census Tract for DTE Electric (Metro Detroit Area)**



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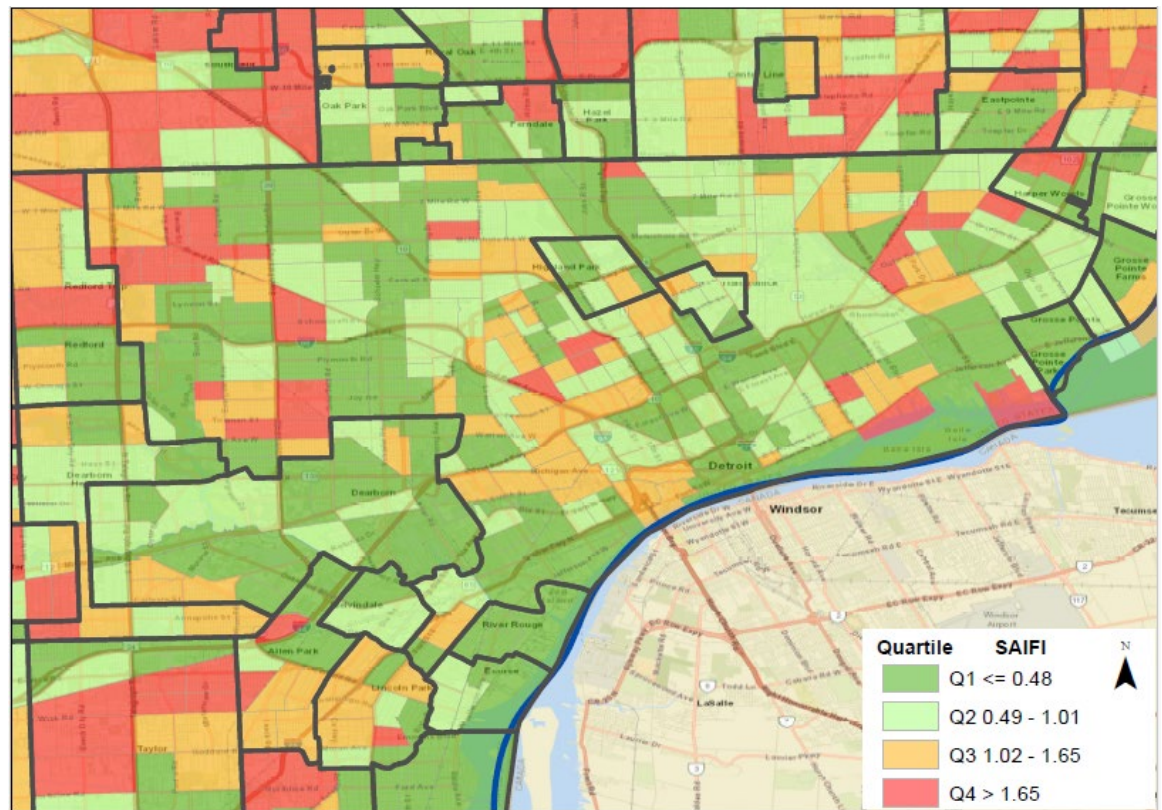
**Figure 6. 2024 All Weather SAIDI by Census Tract for DTE Electric (Full  
Electric Service Area)**





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**Figure 7. 2024 All Weather SAIDI by Census Tract for DTE Electric (Metro Detroit Area)**



**Q67. Are all census tracts equal in geographic size and population?**

A67. 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.<sup>22</sup> 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 viewed in a map, as shown above, the lightly populated,

<sup>22</sup> US Census Bureau, Glossary, available at [Glossary \(census.gov\)](https://www.census.gov/programs-surveys/geography/about/glossary.html?adlt=strict#par_textimage_13), [https://www.census.gov/programs-surveys/geography/about/glossary.html?adlt=strict#par\\_textimage\\_13](https://www.census.gov/programs-surveys/geography/about/glossary.html?adlt=strict#par_textimage_13) accessed March 19, 2025.



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1 geographically large census tracts can visually skew the true reliability impact on  
2 customers.

3

4 **Q68. How many vulnerable census tracts are there in DTE Electric's service**  
5 **territory?**

6 A68. In the DTE Electric service territory, there are 483 census tracts that fall into the  
7 range of having a composite MiEJScreen score at or above 80<sup>th</sup> percentile. These  
8 483 census tracts represent 29% of the total census tracts in DTE Electric's service  
9 area and account for approximately 550,000 residential customers.<sup>23</sup> Additionally,  
10 these tracts include a total of 1,032 circuits out of DTE Electric's 3,273 distribution  
11 circuits (32% of total circuits) and contain 8,080 circuit miles compared to 41,905  
12 total distribution circuit miles (19% of total distribution miles).

13

14 **Q69. Can you show the 2020-2024 reliability data for the grouped EJ customers?**

15 A69. Yes. The reliability performance in years 2020 through 2024, for SAIDI and SAIFI  
16 metrics excluding MEDs and All-Weather compared to the systemwide levels, are  
17 shown in Tables 5-8.

---

<sup>23</sup> There are a total of 1,643 census tracts in DTE Electric's service territory.

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1                   **Table 5            All Weather SAIFI Reliability Performance of Census Tracts**  
2                                   **(MiEJ score of 0% to 100%) Versus System Average**

3

| Census Tract EJ %<br>Group | Category | 2020<br>SAIFI | 2021<br>SAIFI | 2022<br>SAIFI | 2023<br>SAIFI | 2024<br>SAIFI |
|----------------------------|----------|---------------|---------------|---------------|---------------|---------------|
| 0 to 5                     | AW       | 3.12          | 2.88          | 2.37          | 3.01          | 2.42          |
| >5 to 10                   | AW       | 2.46          | 2.47          | 1.95          | 2.22          | 2.42          |
| >10 to 15                  | AW       | 1.68          | 2.29          | 1.94          | 1.97          | 1.90          |
| >15 to 20                  | AW       | 2.13          | 2.00          | 1.49          | 2.02          | 2.07          |
| >20 to 25                  | AW       | 1.55          | 2.29          | 1.56          | 2.15          | 1.39          |
| >25 to 30                  | AW       | 1.47          | 2.01          | 1.43          | 1.99          | 1.33          |
| >30 to 35                  | AW       | 1.26          | 1.96          | 1.49          | 1.93          | 1.48          |
| >35 to 40                  | AW       | 1.32          | 1.72          | 1.31          | 2.21          | 1.22          |
| >40 to 45                  | AW       | 1.08          | 1.50          | 1.12          | 1.86          | 1.08          |
| >45 to 50                  | AW       | 1.42          | 1.58          | 1.17          | 1.64          | 1.22          |
| >50 to 55                  | AW       | 1.25          | 1.53          | 1.16          | 1.68          | 1.21          |
| >55 to 60                  | AW       | 1.10          | 1.39          | 1.37          | 1.52          | 1.22          |
| >60 to 65                  | AW       | 1.18          | 1.29          | 0.96          | 1.51          | 1.12          |
| >65 to 70                  | AW       | 1.15          | 1.48          | 1.18          | 1.90          | 1.36          |
| >70 to 75                  | AW       | 1.29          | 1.58          | 1.13          | 1.58          | 1.27          |
| >75 to 80                  | AW       | 1.20          | 1.50          | 1.08          | 1.71          | 1.16          |
| >80 to 85                  | AW       | 1.23          | 1.56          | 1.18          | 1.47          | 1.24          |
| >85 to 90                  | AW       | 1.11          | 1.14          | 1.12          | 1.54          | 0.98          |
| >90 to 95                  | AW       | 1.04          | 1.33          | 1.03          | 1.52          | 1.00          |
| >95 to 100                 | AW       | 0.83          | 1.19          | 1.15          | 1.49          | 0.73          |
| No EJ Score                | AW       | 0.83          | 0.92          | 1.01          | 1.27          | 0.77          |
| Sytem Average              | AW       | 1.29          | 1.58          | 1.25          | 1.72          | 1.25          |

|  |                                 |
|--|---------------------------------|
|  | Over performing system average  |
|  | Under performing system average |
|  | System average                  |

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1                   **Table 6           Excluding MEDs SAIFI Reliability Performance of Census**  
2                   **Tracts (MiEJ score of 0% to 100%) Versus System Average**

| Census Tract EJ %<br>Group | Category | 2020<br>SAIFI | 2021<br>SAIFI | 2022<br>SAIFI | 2023<br>SAIFI | 2024<br>SAIFI |
|----------------------------|----------|---------------|---------------|---------------|---------------|---------------|
| 0 to 5                     | Ex-MED   | 2.36          | 1.84          | 1.94          | 1.56          | 1.98          |
| >5 to 10                   | Ex-MED   | 1.71          | 1.35          | 1.54          | 1.27          | 1.86          |
| >10 to 15                  | Ex-MED   | 1.17          | 1.47          | 1.55          | 1.01          | 1.47          |
| >15 to 20                  | Ex-MED   | 1.57          | 1.15          | 1.25          | 1.17          | 1.62          |
| >20 to 25                  | Ex-MED   | 1.15          | 1.42          | 1.33          | 1.15          | 1.08          |
| >25 to 30                  | Ex-MED   | 1.12          | 1.16          | 1.17          | 1.13          | 1.00          |
| >30 to 35                  | Ex-MED   | 0.97          | 1.06          | 1.16          | 0.88          | 1.03          |
| >35 to 40                  | Ex-MED   | 1.02          | 0.99          | 1.00          | 1.10          | 0.83          |
| >40 to 45                  | Ex-MED   | 0.91          | 0.85          | 0.88          | 0.81          | 0.76          |
| >45 to 50                  | Ex-MED   | 1.14          | 0.94          | 0.98          | 0.75          | 0.86          |
| >50 to 55                  | Ex-MED   | 1.07          | 0.85          | 0.91          | 0.82          | 0.89          |
| >55 to 60                  | Ex-MED   | 0.88          | 0.84          | 1.10          | 0.77          | 0.91          |
| >60 to 65                  | Ex-MED   | 0.95          | 0.76          | 0.75          | 0.75          | 0.80          |
| >65 to 70                  | Ex-MED   | 0.98          | 0.84          | 0.98          | 0.93          | 1.03          |
| >70 to 75                  | Ex-MED   | 1.07          | 0.95          | 0.90          | 0.75          | 1.00          |
| >75 to 80                  | Ex-MED   | 1.01          | 0.93          | 0.85          | 0.87          | 0.94          |
| >80 to 85                  | Ex-MED   | 0.93          | 0.92          | 0.92          | 0.70          | 0.91          |
| >85 to 90                  | Ex-MED   | 0.85          | 0.68          | 0.78          | 0.71          | 0.80          |
| >90 to 95                  | Ex-MED   | 0.80          | 0.78          | 0.76          | 0.71          | 0.74          |
| >95 to 100                 | Ex-MED   | 0.65          | 0.64          | 0.77          | 0.78          | 0.59          |
| No EJ Score                | Ex-MED   | 0.71          | 0.58          | 0.86          | 0.60          | 0.59          |
| Sytem Average              | Ex-MED   | 1.01          | 0.92          | 0.98          | 0.86          | 0.94          |

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|  | Over performing system average  |
|  | Under performing system average |
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**Table 7 All Weather SAIDI Reliability Performance of Census Tracts**

2

**(MiEJ score of 0% to 100%) Versus System Average**

3

| Census Tract EJ %<br>Group | Category | 2020<br>SAIDI | 2021<br>SAIDI | 2022<br>SAIDI | 2023<br>SAIDI | 2024<br>SAIDI |
|----------------------------|----------|---------------|---------------|---------------|---------------|---------------|
| 0 to 5                     | AW       | 978           | 2656          | 1262          | 3278          | 937           |
| >5 to 10                   | AW       | 863           | 1657          | 909           | 1604          | 867           |
| >10 to 15                  | AW       | 384           | 930           | 916           | 1618          | 625           |
| >15 to 20                  | AW       | 605           | 1096          | 576           | 1184          | 813           |
| >20 to 25                  | AW       | 510           | 1291          | 527           | 1937          | 495           |
| >25 to 30                  | AW       | 414           | 1174          | 611           | 1521          | 551           |
| >30 to 35                  | AW       | 306           | 1211          | 692           | 1748          | 670           |
| >35 to 40                  | AW       | 351           | 1027          | 666           | 1889          | 643           |
| >40 to 45                  | AW       | 222           | 940           | 433           | 1834          | 433           |
| >45 to 50                  | AW       | 330           | 999           | 426           | 1584          | 537           |
| >50 to 55                  | AW       | 292           | 946           | 458           | 1482          | 474           |
| >55 to 60                  | AW       | 300           | 775           | 531           | 1268          | 490           |
| >60 to 65                  | AW       | 297           | 764           | 473           | 1363          | 498           |
| >65 to 70                  | AW       | 228           | 816           | 416           | 1745          | 464           |
| >70 to 75                  | AW       | 336           | 844           | 472           | 1515          | 475           |
| >75 to 80                  | AW       | 325           | 820           | 389           | 1509          | 376           |
| >80 to 85                  | AW       | 480           | 978           | 556           | 1419          | 539           |
| >85 to 90                  | AW       | 351           | 705           | 735           | 1699          | 342           |
| >90 to 95                  | AW       | 329           | 840           | 749           | 1675          | 362           |
| >95 to 100                 | AW       | 266           | 804           | 923           | 1133          | 221           |
| No EJ Score                | AW       | 203           | 355           | 300           | 778           | 224           |
| Sytem Average              | AW       | 352           | 927           | 584           | 1542          | 483           |

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|--|---------------------------------|
|  | Over performing system average  |
|  | Under performing system average |
|  | System average                  |

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**Table 8 Excluding MEDs SAIDI Reliability Performance of Census  
Tracts (MiEJ score of 0% to 100%) Versus System Average**

| Census Tract EJ %<br>Group | Category | 2020<br>SAIDI | 2021<br>SAIDI | 2022<br>SAIDI | 2023<br>SAIDI | 2024<br>SAIDI |
|----------------------------|----------|---------------|---------------|---------------|---------------|---------------|
| 0 to 5                     | Ex-MED   | 342           | 398           | 487           | 373           | 501           |
| >5 to 10                   | Ex-MED   | 291           | 213           | 296           | 320           | 325           |
| >10 to 15                  | Ex-MED   | 153           | 209           | 274           | 236           | 249           |
| >15 to 20                  | Ex-MED   | 218           | 150           | 238           | 212           | 274           |
| >20 to 25                  | Ex-MED   | 168           | 248           | 182           | 239           | 199           |
| >25 to 30                  | Ex-MED   | 176           | 177           | 188           | 217           | 177           |
| >30 to 35                  | Ex-MED   | 123           | 136           | 152           | 158           | 183           |
| >35 to 40                  | Ex-MED   | 147           | 138           | 146           | 173           | 171           |
| >40 to 45                  | Ex-MED   | 108           | 111           | 103           | 152           | 106           |
| >45 to 50                  | Ex-MED   | 154           | 149           | 131           | 135           | 145           |
| >50 to 55                  | Ex-MED   | 144           | 124           | 128           | 136           | 137           |
| >55 to 60                  | Ex-MED   | 102           | 112           | 150           | 155           | 160           |
| >60 to 65                  | Ex-MED   | 132           | 114           | 138           | 139           | 122           |
| >65 to 70                  | Ex-MED   | 101           | 131           | 120           | 138           | 169           |
| >70 to 75                  | Ex-MED   | 154           | 122           | 115           | 119           | 147           |
| >75 to 80                  | Ex-MED   | 124           | 128           | 106           | 145           | 146           |
| >80 to 85                  | Ex-MED   | 158           | 147           | 156           | 149           | 144           |
| >85 to 90                  | Ex-MED   | 123           | 111           | 123           | 130           | 146           |
| >90 to 95                  | Ex-MED   | 136           | 112           | 115           | 129           | 127           |
| >95 to 100                 | Ex-MED   | 118           | 94            | 129           | 142           | 101           |
| No EJ Score                | Ex-MED   | 97            | 68            | 98            | 80            | 88            |
| Sytem Average              | Ex-MED   | 142           | 136           | 146           | 157           | 159           |

|  |                                 |
|--|---------------------------------|
|  | Over performing system average  |
|  | Under performing system average |
|  | System average                  |

4

5 **Q70. What is the distribution of residential customers in each EJ gradation?**

6 A70. The distribution of residential customers in each gradation is highlighted in Table  
7 9 below. Approximately 27% of DTE Electric residential customers fall into the  
8 80% to 100% gradations.

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**Table 9 Residential Customers by EJ Gradations**

| Census Tract EJ % Group            | Number of Residential Customers | % of Residential 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%                         |
| <b>Total Residential Customers</b> | <b>2,056,630</b>                | <b>100%</b>                |

2

3 **Q71. How does the reliability performance of census tracts that have been identified**  
4 **as vulnerable communities compare with the rest of the DTE Electric system?**

5 A71. In short, the census tracts with our most vulnerable customers are, on average,  
6 experiencing more reliable electric service than the rest of the system. The data  
7 does not show any evidence to suggest that those with higher EJ scores experience  
8 comparatively worse service or reliability, and in fact, it suggests that the opposite  
9 is true.

10

11 As noted in Tables 5 through 8, vulnerable customers in the 80<sup>th</sup> percentile and  
12 above generally see better reliability than the system average in SAIFI and SAIDI  
13 in both All-Weather and Non-MED. This was also recognized in the Order in Case

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1 No. U-21534 where the Commission stated..."on average, vulnerable communities  
2 are seeing better reliability performance for both SAIDI and SAIFI in both all-  
3 weather and when excluding MEDs.<sup>24</sup>" All-Weather and Non-MEDs SAIFI is  
4 lower than the system average in every year and every vulnerable community  
5 gradient. For Non-MED SAIDI, the vast majority of years and vulnerable  
6 community gradients are better than the system average. All-Weather shows more  
7 year-gradient combinations above the system average but even for this metric, the  
8 majority of instances are better than the system average.

9

10 **Q72. Has the Company evaluated how its investment programs are reaching**  
11 **vulnerable communities to improve electric distribution infrastructure and**  
12 **reliability performance?**

13 A72. Yes. The Company has evaluated some of its largest distribution investment  
14 projects and programs - 4.8kV Hardening, 4.8kV Conversion, and Tree Trimming  
15 - with respect to if the investment was made in a vulnerable area.

16

17 **Q73. What are the results of the investment analysis related to vulnerable**  
18 **communities?**

19 A73. The results are summarized in Table 10 and show how the Company's investments  
20 are supporting vulnerable customers and communities in southeast Michigan,  
21 including the City of Detroit. This analysis is based on the MiEJScreen Tool census  
22 tract data and Company investment data on the circuits addressed by the following  
23 three programs over the timeframe 2019-2024: 4.8kV Hardening, Tree Trimming  
24 and Conversions. For each of these investment programs, Table 10 shows total

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<sup>24</sup> Case No. U-21534 January 23, 2025 Order, pg. 444.

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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 2020, 85% of work performed under the Hardening program occurred in vulnerable communities. As discussed by Witness Joseph Robinson, 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 10      2020 to 2024 Investment in Vulnerable Communities (Census Tracts with MiEJ Score of 80% to 100%)**

| Investment Program (2020-2024) | Total Investment by Program (\$M) | Total Investment by Program in Vulnerable Census Tracts (\$M) | % Of Investment in Vulnerable Census Tracts |
|--------------------------------|-----------------------------------|---------------------------------------------------------------|---------------------------------------------|
| Conversion                     | \$570                             | \$343                                                         | 60%                                         |
| 4.8kV Hardening                | \$497                             | \$423                                                         | 85%                                         |
| Tree Trim                      | \$915                             | \$212                                                         | 23%                                         |

**Q74. How will these distribution investment programs address vulnerable communities in 2025-2026 based on the Company's planned execution of investments in this case?**

**A74.** For the purpose of this analysis, the Company focused on three of the largest strategic investment programs. Witnesses Stowe, Robinson, and Steudle address the Company's planned investments for 2025 and 2026 for Conversions, Hardening, and Tree Trimming, respectively. Table 11 summarizes total



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investment dollars by program, total program investment in vulnerable communities, and percentage of program investment in vulnerable communities in 2025-2026. These percentages largely mirror the programs' previous levels of investment in vulnerable communities.

**Table 11      2025-2026 Investment in Vulnerable Communities (Census Tracts with MiEJ Score of 80% to 100%)**

| Investment Program<br>(2025-2026) | Total Investment by<br>Program (\$M) | Total Investment by<br>Program in Vulnerable<br>Census Tracts (\$M) | % Of Investment in<br>Vulnerable Census Tracts |
|-----------------------------------|--------------------------------------|---------------------------------------------------------------------|------------------------------------------------|
| Conversion                        | \$542                                | \$321                                                               | 59%                                            |
| 4.8kV Hardening                   | \$255                                | \$221                                                               | 86%                                            |
| Tree Trim                         | \$404                                | \$86                                                                | 21%                                            |

**Q75. Has the Company also analyzed investments using the 5% EJ gradations utilized in the reliability analysis above?**

A75. Yes. The Company analyzed investments pertaining to Hardening, Tree Trim, and Conversion including CODI programs, to provide information in EJ community gradations based on the MiEJScreen score as defined in the December 2023 order in Case No. 21297. 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 12 to Table 17 below demonstrate the Company's investment distribution by program for EJ gradations by year.

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**Table 12      Hardening Investments by EJ Gradations**

| EJ Gradations                | 2020<br>Investment<br>(\$000) | 2021<br>Investment<br>(\$000) | 2022<br>Investment<br>(\$000) | 2023<br>Investment<br>(\$000) | 2024<br>Investment<br>(\$000) | 2025<br>Investment<br>Forecast<br>(\$000) | 2026<br>Investment<br>Forecast<br>(\$000) |
|------------------------------|-------------------------------|-------------------------------|-------------------------------|-------------------------------|-------------------------------|-------------------------------------------|-------------------------------------------|
| 0-5%                         | \$ -                          | \$ -                          | \$ -                          | \$ 1,710                      | \$ -                          | \$ -                                      | \$ -                                      |
| 5-10%                        | \$ -                          | \$ -                          | \$ -                          | \$ -                          | \$ -                          | \$ -                                      | \$ -                                      |
| 10-15%                       | \$ -                          | \$ -                          | \$ -                          | \$ -                          | \$ -                          | \$ -                                      | \$ 3,188                                  |
| 15-20%                       | \$ -                          | \$ -                          | \$ -                          | \$ -                          | \$ -                          | \$ -                                      | \$ -                                      |
| 20-25%                       | \$ -                          | \$ -                          | \$ -                          | \$ -                          | \$ -                          | \$ -                                      | \$ 68                                     |
| 25-30%                       | \$ -                          | \$ -                          | \$ -                          | \$ -                          | \$ -                          | \$ -                                      | \$ 34                                     |
| 30-35%                       | \$ -                          | \$ -                          | \$ -                          | \$ -                          | \$ -                          | \$ -                                      | \$ -                                      |
| 35-40%                       | \$ -                          | \$ -                          | \$ 1,955                      | \$ -                          | \$ -                          | \$ -                                      | \$ 1,579                                  |
| 40-45%                       | \$ -                          | \$ -                          | \$ -                          | \$ -                          | \$ -                          | \$ -                                      | \$ 235                                    |
| 45-50%                       | \$ -                          | \$ -                          | \$ -                          | \$ -                          | \$ -                          | \$ -                                      | \$ 2,951                                  |
| 50-55%                       | \$ -                          | \$ 6,284                      | \$ -                          | \$ -                          | \$ -                          | \$ -                                      | \$ 1,688                                  |
| 55-60%                       | \$ -                          | \$ -                          | \$ -                          | \$ -                          | \$ 289                        | \$ -                                      | \$ 184                                    |
| 60-65%                       | \$ -                          | \$ 1,669                      | \$ 9,026                      | \$ -                          | \$ -                          | \$ -                                      | \$ 1                                      |
| 65-70%                       | \$ -                          | \$ -                          | \$ -                          | \$ -                          | \$ -                          | \$ -                                      | \$ -                                      |
| 70-75%                       | \$ 1,821                      | \$ 3,032                      | \$ 2,747                      | \$ -                          | \$ -                          | \$ 521                                    | \$ 8,453                                  |
| 75-80%                       | \$ 868                        | \$ 16,682                     | \$ 1,691                      | \$ 4,148                      | \$ 273                        | \$ 1,253                                  | \$ 8                                      |
| 80-85%                       | \$ 2,343                      | \$ 646                        | \$ 8,354                      | \$ 12,660                     | \$ 11,987                     | \$ 1,456                                  | \$ 9,440                                  |
| 85-90%                       | \$ 24,086                     | \$ 8,858                      | \$ 22,658                     | \$ 32,545                     | \$ 17,019                     | \$ 21,703                                 | \$ 16,439                                 |
| 90-95%                       | \$ 15,495                     | \$ 13,563                     | \$ 39,625                     | \$ 24,866                     | \$ 23,105                     | \$ 38,257                                 | \$ 46,578                                 |
| 95-100%                      | \$ 9,505                      | \$ 12,315                     | \$ 65,540                     | \$ 40,755                     | \$ 35,393                     | \$ 58,773                                 | \$ 28,004                                 |
| Unmapped/Unscored*           | \$ 1,048                      | \$ 2,313                      | \$ 5,885                      | \$ 10,326                     | \$ 4,200                      | \$ 4,106                                  | \$ 10,579                                 |
| <b>Total Investment (\$)</b> | <b>\$ 55,165</b>              | <b>\$ 65,362</b>              | <b>\$ 157,482</b>             | <b>\$ 127,010</b>             | <b>\$ 92,266</b>              | <b>\$ 126,070</b>                         | <b>\$ 129,429</b>                         |

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**Table 13      Percent of Hardening Investments by EJ Gradations**

| EJ Gradations        | 2020<br>Investment<br>(%) | 2021<br>Investment<br>(%) | 2022<br>Investment<br>(%) | 2023<br>Investment<br>(%) | 2024<br>Investment<br>(%) | 2025<br>Investment<br>Forecast<br>(%) | 2026<br>Investment<br>Forecast<br>(%) |
|----------------------|---------------------------|---------------------------|---------------------------|---------------------------|---------------------------|---------------------------------------|---------------------------------------|
| 0-5%                 | 0%                        | 0%                        | 0%                        | 1%                        | 0%                        | 0%                                    | 0%                                    |
| 5-10%                | 0%                        | 0%                        | 0%                        | 0%                        | 0%                        | 0%                                    | 0%                                    |
| 10-15%               | 0%                        | 0%                        | 0%                        | 0%                        | 0%                        | 0%                                    | 2%                                    |
| 15-20%               | 0%                        | 0%                        | 0%                        | 0%                        | 0%                        | 0%                                    | 0%                                    |
| 20-25%               | 0%                        | 0%                        | 0%                        | 0%                        | 0%                        | 0%                                    | 0%                                    |
| 25-30%               | 0%                        | 0%                        | 0%                        | 0%                        | 0%                        | 0%                                    | 0%                                    |
| 30-35%               | 0%                        | 0%                        | 0%                        | 0%                        | 0%                        | 0%                                    | 0%                                    |
| 35-40%               | 0%                        | 0%                        | 1%                        | 0%                        | 0%                        | 0%                                    | 1%                                    |
| 40-45%               | 0%                        | 0%                        | 0%                        | 0%                        | 0%                        | 0%                                    | 0%                                    |
| 45-50%               | 0%                        | 0%                        | 0%                        | 0%                        | 0%                        | 0%                                    | 2%                                    |
| 50-55%               | 0%                        | 10%                       | 0%                        | 0%                        | 0%                        | 0%                                    | 1%                                    |
| 55-60%               | 0%                        | 0%                        | 0%                        | 0%                        | 0%                        | 0%                                    | 0%                                    |
| 60-65%               | 0%                        | 3%                        | 6%                        | 0%                        | 0%                        | 0%                                    | 0%                                    |
| 65-70%               | 0%                        | 0%                        | 0%                        | 0%                        | 0%                        | 0%                                    | 0%                                    |
| 70-75%               | 3%                        | 5%                        | 2%                        | 0%                        | 0%                        | 0%                                    | 7%                                    |
| 75-80%               | 2%                        | 26%                       | 1%                        | 3%                        | 0%                        | 1%                                    | 0%                                    |
| 80-85%               | 4%                        | 1%                        | 5%                        | 10%                       | 13%                       | 1%                                    | 7%                                    |
| 85-90%               | 44%                       | 14%                       | 14%                       | 26%                       | 18%                       | 17%                                   | 13%                                   |
| 90-95%               | 28%                       | 21%                       | 25%                       | 20%                       | 25%                       | 30%                                   | 36%                                   |
| 95-100%              | 17%                       | 19%                       | 42%                       | 32%                       | 38%                       | 47%                                   | 22%                                   |
| Unmapped/Unscored    | 2%                        | 4%                        | 4%                        | 8%                        | 5%                        | 3%                                    | 8%                                    |
| Total Investment (%) | 100%                      | 100%                      | 100%                      | 100%                      | 100%                      | 100%                                  | 100%                                  |

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**Table 14      Tree Trim Investments by EJ Gradations**

| EJ Gradations        | 2020<br>Investment<br>(\$000) | 2021<br>Investment<br>(\$000) | 2022 Investment<br>(\$000) | 2023 Investment<br>(\$000) | 2024 Investment<br>(\$000) | 2025<br>Investment<br>Forecast<br>(\$000) | 2026<br>Investment<br>Forecast<br>(\$000) |
|----------------------|-------------------------------|-------------------------------|----------------------------|----------------------------|----------------------------|-------------------------------------------|-------------------------------------------|
| 0-5%                 | \$ 948                        | \$ 1,634                      | \$ 3,055                   | \$ 1,487                   | \$ 547                     | \$ 501                                    | \$ 14                                     |
| 5-10%                | \$ 11,250                     | \$ 9,290                      | \$ 4,653                   | \$ 9,113                   | \$ 2,978                   | \$ 3,025                                  | \$ 4,089                                  |
| 10-15%               | \$ 9,756                      | \$ 11,195                     | \$ 12,626                  | \$ 13,319                  | \$ 4,167                   | \$ 2,894                                  | \$ 9,184                                  |
| 15-20%               | \$ 7,037                      | \$ 7,118                      | \$ 6,069                   | \$ 8,227                   | \$ 5,178                   | \$ 6,634                                  | \$ 3,341                                  |
| 20-25%               | \$ 8,683                      | \$ 7,320                      | \$ 11,946                  | \$ 5,077                   | \$ 8,194                   | \$ 10,244                                 | \$ 2,628                                  |
| 25-30%               | \$ 8,551                      | \$ 15,421                     | \$ 12,696                  | \$ 8,208                   | \$ 8,287                   | \$ 6,355                                  | \$ 7,191                                  |
| 30-35%               | \$ 14,158                     | \$ 10,839                     | \$ 16,395                  | \$ 9,867                   | \$ 4,576                   | \$ 8,282                                  | \$ 10,098                                 |
| 35-40%               | \$ 9,332                      | \$ 7,666                      | \$ 15,467                  | \$ 8,204                   | \$ 3,557                   | \$ 12,226                                 | \$ 6,736                                  |
| 40-45%               | \$ 4,657                      | \$ 8,498                      | \$ 13,595                  | \$ 7,857                   | \$ 4,493                   | \$ 9,080                                  | \$ 8,080                                  |
| 45-50%               | \$ 4,847                      | \$ 7,315                      | \$ 11,990                  | \$ 11,789                  | \$ 6,359                   | \$ 11,153                                 | \$ 7,073                                  |
| 50-55%               | \$ 4,730                      | \$ 10,125                     | \$ 13,127                  | \$ 5,841                   | \$ 6,575                   | \$ 9,732                                  | \$ 9,062                                  |
| 55-60%               | \$ 5,338                      | \$ 6,987                      | \$ 10,363                  | \$ 6,555                   | \$ 8,082                   | \$ 9,519                                  | \$ 9,954                                  |
| 60-65%               | \$ 5,864                      | \$ 7,329                      | \$ 9,856                   | \$ 5,702                   | \$ 3,712                   | \$ 10,679                                 | \$ 6,545                                  |
| 65-70%               | \$ 5,860                      | \$ 4,182                      | \$ 11,035                  | \$ 4,402                   | \$ 4,743                   | \$ 9,204                                  | \$ 7,893                                  |
| 70-75%               | \$ 4,676                      | \$ 2,664                      | \$ 4,782                   | \$ 3,696                   | \$ 5,625                   | \$ 10,414                                 | \$ 3,253                                  |
| 75-80%               | \$ 5,980                      | \$ 5,654                      | \$ 10,001                  | \$ 5,855                   | \$ 9,589                   | \$ 12,711                                 | \$ 6,117                                  |
| 80-85%               | \$ 3,119                      | \$ 8,166                      | \$ 15,094                  | \$ 5,759                   | \$ 7,688                   | \$ 11,895                                 | \$ 7,552                                  |
| 85-90%               | \$ 7,664                      | \$ 6,750                      | \$ 13,184                  | \$ 8,647                   | \$ 20,189                  | \$ 11,861                                 | \$ 8,089                                  |
| 90-95%               | \$ 14,559                     | \$ 4,648                      | \$ 16,324                  | \$ 10,152                  | \$ 13,350                  | \$ 14,167                                 | \$ 11,217                                 |
| 95-100%              | \$ 7,846                      | \$ 8,734                      | \$ 13,113                  | \$ 15,055                  | \$ 10,884                  | \$ 10,171                                 | \$ 11,221                                 |
| Unmapped/Unscored*   | \$ 24,073                     | \$ 10,699                     | \$ 19,887                  | \$ 22,648                  | \$ 22,326                  | \$ 41,351                                 | \$ 42,228                                 |
| Total Investment (%) | \$ 168,926                    | \$ 162,235                    | \$ 245,260                 | \$ 177,459                 | \$ 161,099                 | \$ 222,099                                | \$ 181,566                                |

Line  
No.

1

**Table 15      Percent of Tree Trim Investments by EJ Gradations**

| EJ Gradations        | 2020<br>Investment<br>(%) | 2021<br>Investment<br>(%) | 2022<br>Investment<br>(%) | 2023<br>Investment<br>(%) | 2024<br>Investment<br>(%) | 2025<br>Investment<br>Forecast<br>(%) | 2026<br>Investment<br>Forecast<br>(%) |
|----------------------|---------------------------|---------------------------|---------------------------|---------------------------|---------------------------|---------------------------------------|---------------------------------------|
| 0-5%                 | 1%                        | 1%                        | 1%                        | 1%                        | 0%                        | 0%                                    | 0%                                    |
| 5-10%                | 7%                        | 6%                        | 2%                        | 5%                        | 2%                        | 1%                                    | 2%                                    |
| 10-15%               | 6%                        | 7%                        | 5%                        | 8%                        | 3%                        | 1%                                    | 5%                                    |
| 15-20%               | 4%                        | 4%                        | 2%                        | 5%                        | 3%                        | 3%                                    | 2%                                    |
| 20-25%               | 5%                        | 5%                        | 5%                        | 3%                        | 5%                        | 5%                                    | 1%                                    |
| 25-30%               | 5%                        | 10%                       | 5%                        | 5%                        | 5%                        | 3%                                    | 4%                                    |
| 30-35%               | 8%                        | 7%                        | 7%                        | 6%                        | 3%                        | 4%                                    | 6%                                    |
| 35-40%               | 6%                        | 5%                        | 6%                        | 5%                        | 2%                        | 6%                                    | 4%                                    |
| 40-45%               | 3%                        | 5%                        | 6%                        | 4%                        | 3%                        | 4%                                    | 4%                                    |
| 45-50%               | 3%                        | 5%                        | 5%                        | 7%                        | 4%                        | 5%                                    | 4%                                    |
| 50-55%               | 3%                        | 6%                        | 5%                        | 3%                        | 4%                        | 4%                                    | 5%                                    |
| 55-60%               | 3%                        | 4%                        | 4%                        | 4%                        | 5%                        | 4%                                    | 5%                                    |
| 60-65%               | 3%                        | 5%                        | 4%                        | 3%                        | 2%                        | 5%                                    | 4%                                    |
| 65-70%               | 3%                        | 3%                        | 4%                        | 2%                        | 3%                        | 4%                                    | 4%                                    |
| 70-75%               | 3%                        | 2%                        | 2%                        | 2%                        | 3%                        | 5%                                    | 2%                                    |
| 75-80%               | 4%                        | 3%                        | 4%                        | 3%                        | 6%                        | 6%                                    | 3%                                    |
| 80-85%               | 2%                        | 5%                        | 6%                        | 3%                        | 5%                        | 5%                                    | 4%                                    |
| 85-90%               | 5%                        | 4%                        | 5%                        | 5%                        | 13%                       | 5%                                    | 4%                                    |
| 90-95%               | 9%                        | 3%                        | 7%                        | 6%                        | 8%                        | 6%                                    | 6%                                    |
| 95-100%              | 5%                        | 5%                        | 5%                        | 8%                        | 7%                        | 5%                                    | 6%                                    |
| Unmapped/Unscored*   | 14%                       | 7%                        | 8%                        | 13%                       | 14%                       | 19%                                   | 23%                                   |
| Total Investment (%) | 100%                      | 100%                      | 100%                      | 100%                      | 100%                      | 100%                                  | 100%                                  |

2

3

**Table 16      Conversion Investments by EJ Gradations**

4

| EJ Gradations         | 2020<br>Investment<br>(\$000) | 2021<br>Investment<br>(\$000) | 2022<br>Investment<br>(\$000) | 2023<br>Investment<br>(\$000) | 2024<br>Investment<br>(\$000) | 2025<br>Investment<br>Forecast<br>(\$000) | 2026<br>Investment<br>Forecast<br>(\$000) |
|-----------------------|-------------------------------|-------------------------------|-------------------------------|-------------------------------|-------------------------------|-------------------------------------------|-------------------------------------------|
| 0-5%                  | \$ -                          | \$ -                          | \$ -                          | \$ -                          | \$ -                          | \$ -                                      | \$ -                                      |
| 5-10%                 | \$ -                          | \$ 127                        | \$ 51                         | \$ 399                        | \$ 1,845                      | \$ 2,495                                  | \$ 1,777                                  |
| 10-15%                | \$ 660                        | \$ 464                        | \$ 1,118                      | \$ 439                        | \$ 847                        | \$ 7,030                                  | \$ 17,375                                 |
| 15-20%                | \$ 665                        | \$ 2,359                      | \$ 5,468                      | \$ 1,748                      | \$ 4,130                      | \$ 1,889                                  | \$ 474                                    |
| 20-25%                | \$ 692                        | \$ 2,423                      | \$ 7,370                      | \$ 3,787                      | \$ 3,530                      | \$ 5,670                                  | \$ 6,864                                  |
| 25-30%                | \$ 324                        | \$ 523                        | \$ 480                        | \$ 2,094                      | \$ 7,552                      | \$ 3,998                                  | \$ 434                                    |
| 30-35%                | \$ 427                        | \$ 3,753                      | \$ 9,445                      | \$ 3,464                      | \$ 5,509                      | \$ 3,007                                  | \$ 2,896                                  |
| 35-40%                | \$ 112                        | \$ 143                        | \$ 329                        | \$ 319                        | \$ 298                        | \$ 154                                    | \$ 1,328                                  |
| 40-45%                | \$ -                          | \$ 16                         | \$ 65                         | \$ 235                        | \$ 231                        | \$ 2,149                                  | \$ 1,060                                  |
| 45-50%                | \$ 14                         | \$ 505                        | \$ 4,188                      | \$ 1,656                      | \$ 1,825                      | \$ 8,105                                  | \$ 5,622                                  |
| 50-55%                | \$ 154                        | \$ 380                        | \$ 1,141                      | \$ 887                        | \$ 2,512                      | \$ 7,650                                  | \$ 3,772                                  |
| 55-60%                | \$ 50                         | \$ 793                        | \$ 2,362                      | \$ 6,227                      | \$ 12,599                     | \$ 8,109                                  | \$ 5,356                                  |
| 60-65%                | \$ 176                        | \$ 340                        | \$ 106                        | \$ 497                        | \$ 1,586                      | \$ 4,438                                  | \$ 9,943                                  |
| 65-70%                | \$ 58                         | \$ 595                        | \$ 1,101                      | \$ 8,909                      | \$ 22,346                     | \$ 15,757                                 | \$ 9,923                                  |
| 70-75%                | \$ 114                        | \$ 1,001                      | \$ 295                        | \$ 833                        | \$ 1,909                      | \$ 2,047                                  | \$ 2,073                                  |
| 75-80%                | \$ 3,125                      | \$ 3,149                      | \$ 4,188                      | \$ 11,090                     | \$ 27,324                     | \$ 22,160                                 | \$ 18,353                                 |
| 80-85%                | \$ 183                        | \$ 816                        | \$ 3,335                      | \$ 11,149                     | \$ 12,555                     | \$ 24,419                                 | \$ 16,166                                 |
| 85-90%                | \$ 297                        | \$ 2,147                      | \$ 4,319                      | \$ 11,646                     | \$ 10,913                     | \$ 25,468                                 | \$ 20,296                                 |
| 90-95%                | \$ 1,157                      | \$ 4,732                      | \$ 8,542                      | \$ 18,081                     | \$ 28,032                     | \$ 25,348                                 | \$ 34,864                                 |
| 95-100%               | \$ 15,814                     | \$ 32,162                     | \$ 44,649                     | \$ 67,524                     | \$ 61,180                     | \$ 70,558                                 | \$ 94,743                                 |
| Unmapped/Unscored*    | \$ 437                        | \$ 2,665                      | \$ 5,930                      | \$ 11,126                     | \$ 12,756                     | \$ 22,103                                 | \$ 26,310                                 |
| Total Investment (\$) | \$ 24,460                     | \$ 59,092                     | \$ 104,483                    | \$ 162,109                    | \$ 219,479                    | \$ 262,554                                | \$ 279,627                                |

Line  
No.

1  
2

**Table 17      Percent of Conversion Investments by EJ Gradations**

| EJ Gradations        | 2020<br>Investment<br>(%) | 2021<br>Investment<br>(%) | 2022<br>Investment<br>(%) | 2023<br>Investment<br>(%) | 2024<br>Investment<br>(%) | 2025<br>Investment<br>Forecast<br>(%) | 2026<br>Investment<br>Forecast<br>(%) |
|----------------------|---------------------------|---------------------------|---------------------------|---------------------------|---------------------------|---------------------------------------|---------------------------------------|
| 0-5%                 | 0%                        | 0%                        | 0%                        | 0%                        | 0%                        | 0%                                    | 0%                                    |
| 5-10%                | 0%                        | 0%                        | 0%                        | 0%                        | 1%                        | 1%                                    | 1%                                    |
| 10-15%               | 3%                        | 1%                        | 1%                        | 0%                        | 0%                        | 3%                                    | 6%                                    |
| 15-20%               | 3%                        | 4%                        | 5%                        | 1%                        | 2%                        | 1%                                    | 0%                                    |
| 20-25%               | 3%                        | 4%                        | 7%                        | 2%                        | 2%                        | 2%                                    | 2%                                    |
| 25-30%               | 1%                        | 1%                        | 0%                        | 1%                        | 3%                        | 2%                                    | 0%                                    |
| 30-35%               | 2%                        | 6%                        | 9%                        | 2%                        | 3%                        | 1%                                    | 1%                                    |
| 35-40%               | 0%                        | 0%                        | 0%                        | 0%                        | 0%                        | 0%                                    | 0%                                    |
| 40-45%               | 0%                        | 0%                        | 0%                        | 0%                        | 0%                        | 1%                                    | 0%                                    |
| 45-50%               | 0%                        | 1%                        | 4%                        | 1%                        | 1%                        | 3%                                    | 2%                                    |
| 50-55%               | 1%                        | 1%                        | 1%                        | 1%                        | 1%                        | 3%                                    | 1%                                    |
| 55-60%               | 0%                        | 1%                        | 2%                        | 4%                        | 6%                        | 3%                                    | 2%                                    |
| 60-65%               | 1%                        | 1%                        | 0%                        | 0%                        | 1%                        | 2%                                    | 4%                                    |
| 65-70%               | 0%                        | 1%                        | 1%                        | 5%                        | 10%                       | 6%                                    | 4%                                    |
| 70-75%               | 0%                        | 2%                        | 0%                        | 1%                        | 1%                        | 1%                                    | 1%                                    |
| 75-80%               | 13%                       | 5%                        | 4%                        | 7%                        | 12%                       | 8%                                    | 7%                                    |
| 80-85%               | 1%                        | 1%                        | 3%                        | 7%                        | 6%                        | 9%                                    | 6%                                    |
| 85-90%               | 1%                        | 4%                        | 4%                        | 7%                        | 5%                        | 10%                                   | 7%                                    |
| 90-95%               | 5%                        | 8%                        | 8%                        | 11%                       | 13%                       | 10%                                   | 12%                                   |
| 95-100%              | 65%                       | 54%                       | 43%                       | 42%                       | 28%                       | 27%                                   | 34%                                   |
| Unmapped/Unscored    | 2%                        | 5%                        | 6%                        | 7%                        | 6%                        | 8%                                    | 9%                                    |
| Total Investment (%) | 100%                      | 100%                      | 100%                      | 100%                      | 100%                      | 100%                                  | 100%                                  |

3

4    **Q76.    What do the Tables 10-17 show?**

5    A76.    The tables demonstrate that a significant portion of the Company's reliability  
6           improvement work is being conducted in vulnerable communities. This data shows  
7           that the Company is following through on its commitment to improving service  
8           reliability for customers in vulnerable communities. As highlighted in Table 10,  
9           85%, 60%, and 23% of the investment in the 4.8kV Hardening, 4.8kV Conversion,  
10          and Tree Trim programs for the time period 2020 to 2024 was made in vulnerable  
11          communities. Meaningful investment is expected to continue in vulnerable  
12          communities in future years 2025-2026 as illustrated in Table 11 including 86%,  
13          59%, and 21% of the total investment in the Hardening, Conversion, and Tree Trim  
14          programs respectively. Both the Company's historical and future projected

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1 investment is consistent with DTE Electric's commitment to improving reliability  
2 in vulnerable communities.

3

4 **Q77. Beyond the GPM, how else is EJ impacting the Company's investment**  
5 **decisions?**

6 A77. The Company is using an EJ Multiplier, calculated in the same way as the GPM EJ  
7 multiplier discussed above, to adjust benefit cost ratios used for prioritizing circuits  
8 within the PTMM and Automation Programs. The Company further intends to use  
9 the EJ multiplier as an input to PTMM and Automation circuit prioritization for the  
10 2027-2029 IRM Plans going forward. Witnesses Rademacher and Robinson  
11 discuss this in their respective testimonies.

12

13 **Q78. How is the Company addressing the circuits with the worst reliability that**  
14 **have also been identified as serving vulnerable customers?**

15 A78. The Company has either already invested in recent improvements or has plans to  
16 improve the performance of the fourth quartile worst performing circuits that are in  
17 vulnerable communities through our Tree Trim, PTMM, Conversion, Customer  
18 Excellence, and 4.8kV Hardening investment programs. The Company has  
19 identified 185 distribution circuits in vulnerable communities which fall in the  
20 fourth quartile for reliability performance based on a five-year historic average.  
21 Approximately 46% of the fourth quartile circuits have recently had reliability work  
22 performed, while 51% of the circuits are planned to be addressed in 2025-2026  
23 investment programs.

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1   **Q79. What are the Company's future plans to address EJ in the context of**  
2       **distribution planning and operations?**

3   A79. DTE Electric plans to continue to analyze reliability and investment data using the  
4       MiEJScreen tool, including the consideration of any updates based on the state's  
5       release of the tool's latest version. The Company intends to continue to include EJ  
6       considerations in investment decisions for all areas, as well as continue to address  
7       poor performing circuits in vulnerable communities. Additionally, DTE Electric is  
8       working with MPSC Staff and Stakeholders on a collaborative regression analysis  
9       considering the MiEJScreen Tool Score and reliability metrics for inclusion in the  
10      Company's next DGP as directed by the Commission.<sup>25</sup>

11

12   **Q80. Does this complete your direct testimony?**

13   A80. Yes, it does.

---

<sup>25</sup> On December 1, 2023, the Commission issued an order in Case No. U-21297 (page 352) requesting DTEE to work with Commission Staff and stakeholders to develop regression analysis of customer demographics and reliability for vulnerable communities.

## 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-21860

## QUALIFICATIONS

AND

## DIRECT TESTIMONY

OF

JOSEPH E. ROBINSON



**DTE ELECTRIC COMPANY**  
**QUALIFICATIONS AND DIRECT TESTIMONY OF JOSEPH E. ROBINSON**

Line  
No.

1     **I. Background & Qualifications**

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

3     A1.    My name is Joseph E. Robinson. My business address is One Energy Plaza, Detroit,  
4            Michigan 48226. I am employed by DTE Electric (“DTE Electric” or the “Company”).

5

6     **Q2.    On whose behalf are you testifying?**

7     A2.    I am testifying on behalf of DTE Electric.

8

9     **Q3.    Please state your educational background.**

10    A3.    I hold a Bachelor of Science in Electrical Engineering and a Master of Science in  
11            Electrical Engineering, both from Michigan Technological University.

12

13    **Q4.    Please summarize your work experience.**

14    A4.    In 1993, I joined DTE Electric (formerly the Detroit Edison Company) as an electrical  
15            engineer in the Fossil Generation Engineering organization. I had varying and  
16            increasing responsibilities within the Engineering organization that included industrial  
17            control system design and implementation across the Fossil Generation power plants.  
18            In 2004, I was promoted to Engineering Supervisor responsible for developing and  
19            implementing the process control and technology strategy to improve power plant  
20            performance and reliability. In 2007, I was promoted to Manager of Engineering,  
21            Monroe Power Plant, and assumed overall responsibility for plant performance and  
22            reliability. One of the projects I led in this role optimized plant fuel blending  
23            capabilities and significantly reduced plant fuel costs. I remained there until early 2014,  
24            then transitioned to the role of Manager of Continuous Improvement (CI), Distribution  
25            Operations (DO). In this role, I led the team supporting advancements in the

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1 Distribution Operations CI program. In late 2014, I transitioned to the tree trimming  
2 program. As Manager of Tree Trimming, I was responsible for implementation of the  
3 enhanced tree trimming program that included: a four-phase tree trimming process,  
4 technology implementation, improved organizational structure, and contract  
5 management that resulted in a reduction of tree related outages. In late 2015, I was  
6 promoted to Director of NERC Compliance. In this role, I led the Company's NERC  
7 compliance program, reduced the risks to the security and reliability of the bulk electric  
8 system, and ensured compliance to the NERC reliability standards. In June 2019, I  
9 transitioned to Distribution Operations to the position of Director of System  
10 Operations. In this role, I was responsible for the operation of DTE Electric's electric  
11 grid that included bulk power coordination, subtransmission system operation, and  
12 distribution system operation. In December 2019, I assumed the position of Director,  
13 Central Engineering for Distribution Operations. In this role, I led the organization that  
14 is responsible for determining the health of the Company's electric distribution assets  
15 and developing projects and programs to maintain and improve their safe, reliable, and  
16 cost-effective operation. I oversaw Central Engineering activities, which include  
17 defining technical standards for the equipment to be utilized on the distribution system,  
18 long-term system planning including grid modernization, and developing major  
19 projects needed for customer connections, relocations, increasing loads, infrastructure  
20 improvements, reliability upgrades, and technology enhancements. In February 2023,  
21 I transitioned to the role of Director, Audit Response within Electric Distribution  
22 Operations (DO). In this role, I led the DTE Electric DO Audit Response team that  
23 was responsible for preparation, execution, and overall coordination to support the  
24 MPSC audit that was directed in Case No. U-21305. In July 2024, I transitioned to my  
25 current role as the Director of DO Asset & Work Management.

Line  
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1     **Q5.   What are your current duties and responsibilities?**

2     A5.   As Director of DO Asset & Work Management, I lead the team that is responsible for  
3           the power delivery asset lifecycle health and condition monitoring to obtain greater  
4           asset performance and system reliability.

5

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

8     A6.   Yes. I have sponsored testimony in the following cases:

9           U-17767       2014 DTE Electric Rate Case

10          U-20836       2022 DTE Electric Rate Case

11          U-21193       2023 DTE Electric Integrated Resource Plan

12          U-21297       2023 DTE Electric Rate Case

Line  
No.

1 **II. Overview & Executive Summary**

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

3 A7. The purpose of my testimony is to support, as reasonable, prudent, and necessary, the  
4 historical test period for both the capital and Operations and Maintenance (O&M)  
5 expenditures for 2023, and projected capital and O&M expenditures for the 24-month  
6 bridge period between January 1, 2024, through December 31, 2025, and the projected  
7 test period which runs from January 1, 2026 through December 31, 2026, in the  
8 distribution strategic capital category of the Infrastructure Resilience and Hardening  
9 pillar.

10

11 **Q8. How is your testimony organized?**

12 A8. Following the introductory material above and the executive summary material below,  
13 my testimony is organized by programs and projects within the Infrastructure  
14 Resilience and Hardening pillar as follows:

15 III. 4.8 kV Hardening Program

16 IV. The Pole and Pole-Top Maintenance and Modernization Program ("PTMM")

17 V. Small Wire Replacement Program

18 VI. Preventative Maintenance ("PM") Program

19 VII. System Equipment Replacement Program.

20 A. Substation

21 B. Overhead Equipment Investments

22 C. Underground System Investments

23 D. Station Upgrade Projects

24 VIII. Major Event Risk

25 A. Substation Risk

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1 B. Mobile Fleet Program

2 C. Portable Generators

3 IX. Pontiac Vaults

4 X. Short Cycle Maintenance Programs for Low Reliability Circuits

5 A. Frequent Outage Programs (“Customers Experiencing Multiple Interruptions,  
6 CEMI”)

7

8 **Q9. Are you sponsoring any exhibits in this proceeding?**

9 A9. Yes. I am supporting the following exhibits:

| 10 | <u>Exhibit</u> | <u>Schedule</u> | <u>Description</u>                                         |
|----|----------------|-----------------|------------------------------------------------------------|
| 11 | A-12           | B5.4            | Projected Capital Expenditures – Distribution Plant (Pages |
| 12 |                |                 | 1-3, 10, 16-23)                                            |
| 13 | A-12           | B5.4.8          | Electric Rate Case (ERC) and Infrastructure                |
| 14 |                |                 | Recovery Mechanism (IRM) Revenue Recovery Partition        |
| 15 | A-23           | M5              | Distribution Plant Capital Project Detail – The            |
| 16 |                |                 | Infrastructure Resilience and Hardening                    |
| 17 | A-23           | M9              | Wood Pole Maintenance Specification                        |
| 18 | A-23           | M10             | Pole Top Maintenance Specification                         |
| 19 | A-23           | M11             | PTMM Audit Recommendation Analysis                         |
| 20 | A-23           | M13             | PTMM Industry Standards Summary                            |
| 21 | A-23           | M15             | 4.8kV Hardening Program Alternative Analysis               |

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

2     A10. Yes, they were.

3

4     **Q11. Can you explain the focus and goals of the Company's Infrastructure Resilience**  
5     **and Hardening pillar?**

6     A11. The Infrastructure Resilience and Hardening pillar, as introduced by Witness Chiu,  
7     includes programs and projects focused on near-term grid infrastructure investments  
8     that harden the system against an increasing frequency and severity of high winds and  
9     storms,<sup>1</sup> address frequent outage circuits, and replace damaged and/or defective  
10    infrastructure, or equipment that is beyond useful life expectancy, determined by asset  
11    health assessments, as I discuss later in my testimony. Additionally, investments in this  
12    pillar are essential to maintain the Company's electric distribution system and meet  
13    customer expectations for safety, reliability, power capacity, and quality.

14

15    **Q12. What investment are you supporting with this testimony in the instant case?**

16    A12. My testimony supports both capital and operations and maintenance (O&M) costs  
17    related to the Infrastructure Resilience and Hardening pillar. Supported capital  
18    investments include, approximately \$379 million in the 2023 historical test year,  
19    approximately \$707 million within the 24-month bridge period between January 1,  
20    2024, through December 31, 2025, and approximately \$449 million in the projected  
21    test year spanning from January 1, 2026, to December 31, 2026.<sup>2</sup> The O&M projected  
22    adjustments supported through this testimony is approximately \$27 million in the  
23    projected test year spanning from January 1, 2026, to December 31, 2026.<sup>3</sup>

---

<sup>1</sup> See the discussion by Company Witness Chiu on the severity of recent storm impacts to a grid that is in need of significant system hardening.

<sup>2</sup> U-21860 Ex. A-12, Sch. B5.4, p 1

<sup>3</sup> U-21860 Ex. A-13, Sch. C5.6, p. 2

Line  
No.

1     **Q13. What O&M costs are you sponsoring?**

2     A13. I sponsor the Pole Top Maintenance inspections, both pole and pole top inspections,  
3           infrared thermography, as well as the Preventative Maintenance (PM) program and  
4           Corrective Maintenance (CM), with the Corrective Maintenance category split between  
5           capital and O&M. Additionally, I sponsor system cable testing within the system cable  
6           program.

7  
8     **Q14. How does the Infrastructure Resilience and Hardening pillar relate to the**  
9           **Company's Distribution Operations Business Unit's investment strategy?**

10    A14. As Company Witnesses Chiu and Kryscynski explain in their direct testimonies, the  
11          Company's Distribution Operations Business Unit ("Distribution Operations" or  
12          "DO") identified the operating priorities of: (1) employee and public safety, (2) keeping  
13          the lights on, (3) connecting new load, and (4) reliability improvements and the  
14          strategic investments associated with those priorities are divided across four pillars,  
15          one of which is the Infrastructure Resilience and Hardening pillar. The Infrastructure  
16          Resilience and Hardening pillar is comprised of programs and projects designed to  
17          improve the foundation of DTE Electric's distribution system and make it safer and  
18          more reliable and resilient.

19  
20          In that regard, it focuses investments on equipment replacement for equipment that fails  
21          inspection, is defective and prone to premature failure, is at or nearing the end of its  
22          useful life, or is obsolete, meaning there is limited availability of spare replacement  
23          parts. Replacing failed, failing, and obsolete equipment is essential for maintaining  
24          and improving the Company's distribution service.

Line  
No.

1     **III. 4.8kV Hardening Program**

2     **Q15. Please explain the purpose and scope of the 4.8kV Hardening Program.**

3     A15. The 4.8kV Hardening Program's goals are to enhance public and employee safety,  
4         improve customer reliability, and reduce grid risk by increasing grid resiliency. It  
5         supports safety by removing Detroit Public Lighting Department ("DPLD") arc wire  
6         that is co-located with DTE Electric equipment and at risk of becoming energized. Two  
7         features specific to the City of Detroit distribution infrastructure dictate the scope of  
8         the Program: (1) the existence of DPLD arc wire owned by the City of Detroit and (2)  
9         the co-location of the DPLD arc wire with Company infrastructure. Accordingly, the  
10        Program does not address DPLD arc wire that is not co-located with the Company's  
11        existing infrastructure, as it does not pose the same safety risk when it is not co-located  
12        with the Company's existing infrastructure. More specifically, the Program focuses on  
13        the co-located DPLD arc wire because it may present a safety risk due to its close  
14        proximity to energized wire and its potential for energization. Further, while the  
15        Program does not target areas that do not contain DPLD arc wire, there are instances  
16        where a circuit contains some arc wire, but that arc wire is not along the entirety of the  
17        circuit. In those instances, the Program will harden the entire circuit to optimize  
18        program investment, as there is inherent cost to plan work and mobilize crews and there  
19        are resulting benefits to all customers in the area in terms of improved safety and  
20        reliability. In summary, the Program enhances grid safety by removing DPLD arc wire  
21        that is co-located with DTE Electric equipment and is at risk of becoming energized,  
22        as well as improves reliability by replacing damaged poles and pole-top equipment in  
23        areas with some of the oldest infrastructure in DTE Electric's service territory.



Line  
No.

1 The Company implemented the Program beginning in 2018 to address all overhead  
2 circuits in and around the city of Detroit in areas known to contain DPLD arc wire.

3 The Program's work activities include:

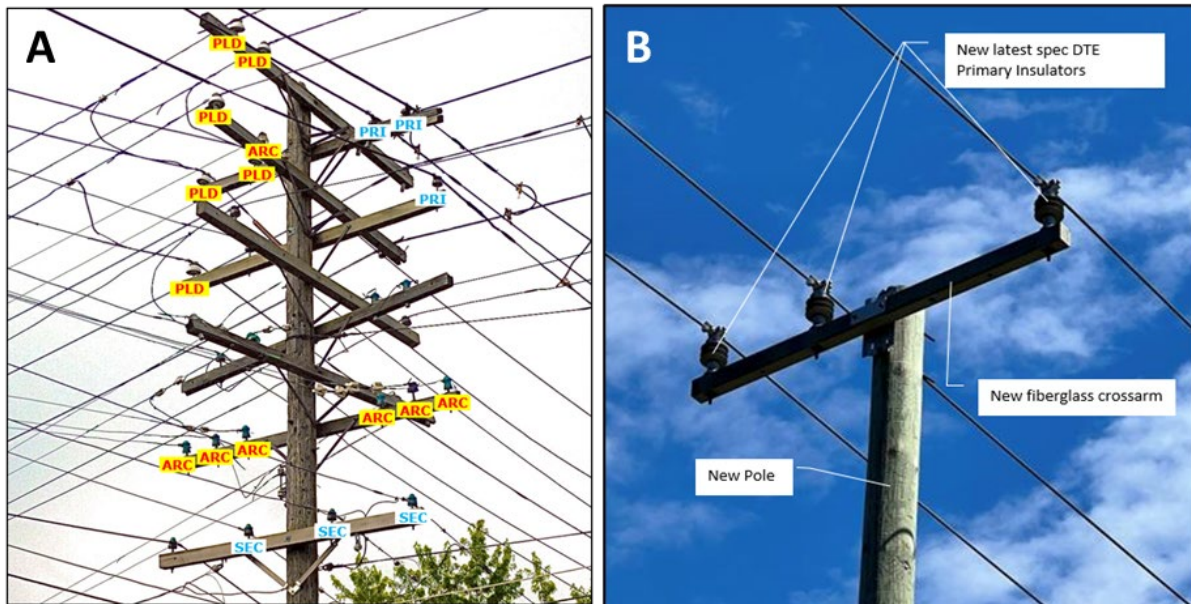
- 4 • Inspecting all utility poles that have Company equipment attached and replace  
5 or reinforce those poles as needed;
- 6 • Trimming trees, as required, to support construction activities;
- 7 • Removing DPLD arc wire from Company-owned equipment and leaving  
8 Company wires in a safe configuration;
- 9 • Removing DPLD distribution wire from Company-owned equipment when it  
10 can be confirmed that the wire is not serving customers;
- 11 • Replacing wooden crossarms with fiberglass crossarms as needed;
- 12 • Replacing other pole-top equipment as required, allowing for rebalancing of the  
13 remaining conductor;
- 14 • Removing service lines to abandoned properties; and
- 15 • Performing any additional work necessary as dictated by field conditions.

16 Upon completion of the 4.8kV Hardening Program's work activities, the Company will  
17 have inspected almost every pole on the selected circuits, and the poles will have new  
18 cross arms and pole-top equipment where needed, as shown in Figure 1 below. As a  
19 result, the distribution infrastructure will be safer and more reliable.

Line  
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1

**Figure 1. (A) Before Hardening and (B) After Hardening**



Shown above is an example of a pole (A) before hardening and a pole (B) after hardening. Note the terms above: PLD - DPLD Distribution Wire; ARC - DPLD Arc Wire; PRI - DTE Electric Primary Wire; and SEC - DTE Electric Secondary Wire

**Q16. Has the 4.8kV Hardening Program always included tree trimming and pole and pole-top equipment replacement in addition to the removal of DPLD arc wire?**

**A16.** Yes, as the Company explained in the last rate proceeding, Case No. U-21534, these activities are necessary for worksite accessibility and improved safety. Specifically, tree trimming is necessary for field crews to access the poles and wires to perform the work activities, and testing and replacing or reinforcing poles is necessary to improve safety for the field crews and the public, as well as to support improved resiliency and reliability. The replacement or reinforcement of poles enhances safety by ensuring the infrastructure is more resilient to weather and other external factors, such as tree interference and vehicle accidents. This pole focused work also reduces the risk of poles breaking and/or downed wires, thereby improving protection for both the public and crews from potential electrical hazards.

Line  
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1     **Q17. How does the 4.8kV Hardening Program benefit customers?**

2     A17. The Company's studies show that the 4.8kV Hardening Program is effective in  
3     improving the safety, reliability, and resiliency of circuits (See Figures 2, 3, and 4).

4

5     In part of its internal evaluation of the Program, the Company reviewed the three-year  
6     historic average for reliability and wire downs of the circuits hardened prior to the year  
7     they were hardened, and compared those numbers to the year after hardening of those  
8     circuits was complete. The Company also reviewed the three-year historic average for  
9     reliability and wire downs for circuits in the city of Detroit that were not subject to  
10    work activities as part of the Program (*i.e.*, the "control group"). As part of this  
11    evaluation, three key metrics were reviewed to determine the effectiveness of the 4.8kV  
12    Hardening Program: (1) All-Weather System Average Interruption Frequency Index  
13    ("SAIFI"), (2) System Average Interruption Duration Index ("SAIDI") excluding  
14    major event days ("Ex-MED<sup>4</sup>s"), and (3) Wire Downs.

15

16    The first metric, All-Weather SAIFI, reflects the frequency of the outage events  
17    experienced by customers on the circuits regardless of weather conditions. The second  
18    metric, SAIDI Ex-MEDs, is an indicator of the amount of time customers are without  
19    power excluding the most significant weather event days, such as very large storms.  
20    And, the third metric, wire downs, serves as a measure of the safety improvements for  
21    the circuits that were hardened where there is a reduction in the total number of wire  
22    downs over a set period of time.

---

<sup>4</sup> 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>.

Line  
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Figure 2 shows the All-Weather SAIFI improvement of hardened circuits versus the control group. The customers on hardened circuits experienced a 36% improvement in All-Weather SAIFI, while the control group circuits degraded by 27%, resulting in a net improvement of 63% for hardened circuits.

**Figure 2. 4.8kV Hardening All-Weather SAIFI**

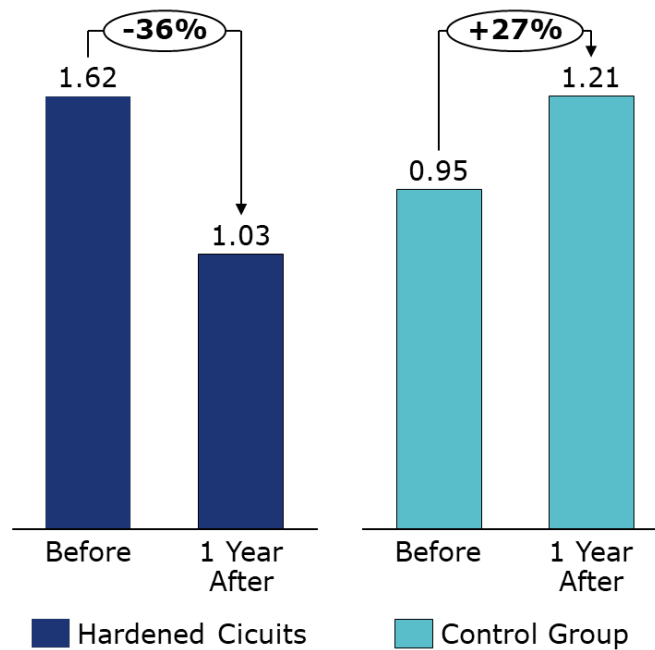
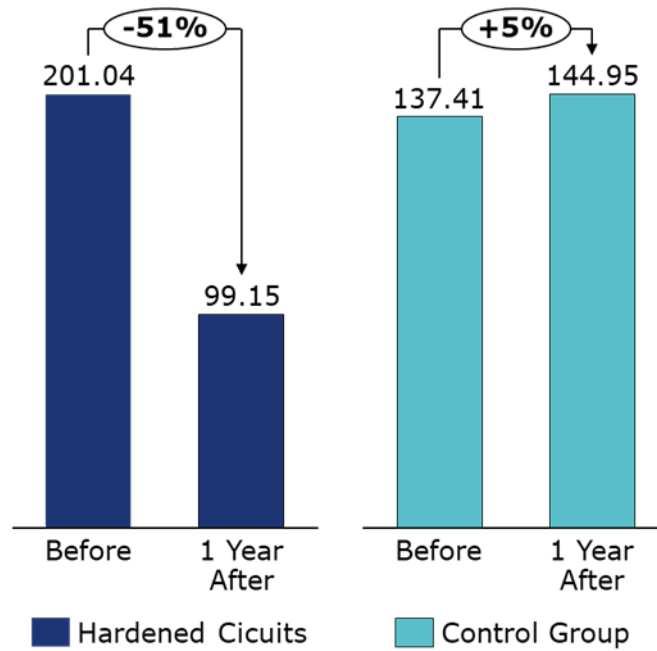


Figure 3 shows the SAIDI Ex-MEDs improvement of hardened circuits versus the control group. On this metric, the customers on hardened circuits experienced a 51% improvement in SAIDI Ex-MEDs, while the control group degraded by 5%. Thus, there was a resulting net improvement of 56% for hardened circuits.

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1

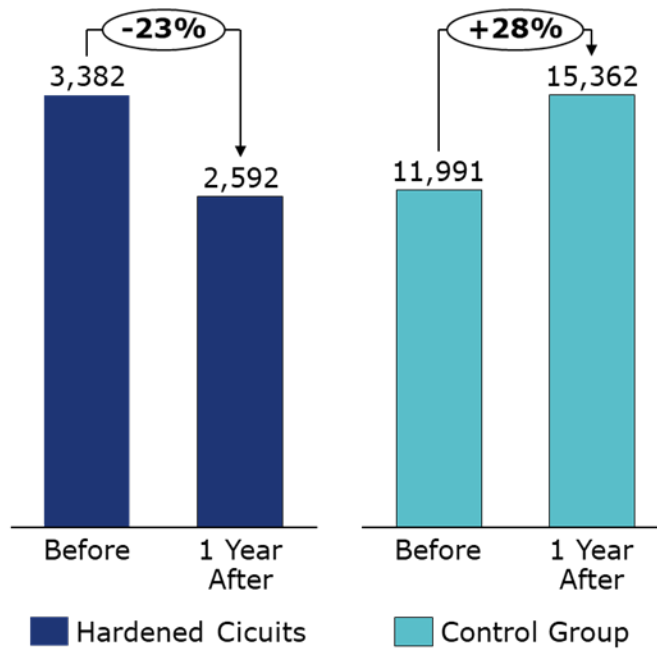
Figure 3. 4.8kV Hardening SAIDI excluding MEDs



2

3

Figure 4. 4.8kV Hardening Wire-downs



Line  
No.

1 Figure 4 shows the wire down event improvement of hardened circuits versus the  
2 control group. The customers on hardened circuits demonstrated a 23% improvement  
3 in wire down events, while the control group degraded by 28%. This was a net  
4 improvement of 51% for hardened circuits.

5

6 **Q18. Are there additional benefits in the 4.8 kV Hardening Program beyond the**  
7 **reliability benefits of tree trimming?**

8 A18. Yes, as I explain below, the Commission found in Case No. U-21534 that “DTE  
9 Electric demonstrated the benefits that are accruing to customers as a result of both  
10 hardening and wire removal” and that the Company did not need to “show that the  
11 improved reliability metrics are solely due to the hardening effort in order to find value  
12 in this work.”<sup>5</sup>.

13

14 **Q19. How has the Commission responded to the Company’s prior investments in the**  
15 **4.8kV Hardening Program, including DTE Electric’s associated work activities**  
16 **you described?**

17 A19. The Commission approved the Company’s 4.8kV Hardening Program investments in  
18 Case Nos. U-20162, U-20561, U-20836, U-21297, and most recently was “not  
19 persuaded to adopt the large disallowances” proposed in Case No. U-21534. (U-21534  
20 - Commission Order, January 23, 2025, p. 104). Further, the 4.8kV Hardening Program  
21 aligns with the Commission’s expectation that the Company remove DPLD arc wire.<sup>6</sup>

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<sup>5</sup> Case No. U-21534 Order dated January 23, 2025, p. 104

<sup>6</sup> 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, p. 6.)

Line  
No.

1 The Commission reiterated its support for the Company's 4.8kV Hardening Program  
2 in Case No. U-21534 stating:

3 Beyond the primary safety issue, DTE Electric demonstrated the  
4 benefits that are accruing to customers as a result of both hardening and  
5 wire removal. For example, all-weather SAIFI and SAIDI excluding  
6 MEDs have both improved in the wake of the hardening effort, as have  
7 wire downs. While not a formal BCA, the Commission is satisfied with  
8 the level of quantification reflected in the company's evidence.  
9 Moreover, the Commission does not find that the company needs to  
10 show that the improved reliability metrics are solely due to the  
11 hardening effort in order to find value in this work. This program was  
12 never expected to eliminate the risk of all downed wires, but it is clearly  
13 addressing the risk associated with downed arc wire. The company has  
14 also shown that the benefits of the hardening and tree trimming will not  
15 necessarily be lost when the conversion to 13.2kV takes place (such as  
16 retention of the crossarms); the program is not redundant with PTMM;  
17 and it doubles the number of circuit miles addressed for tree trimming,  
18 pole top inspection and replacement, and pole inspection and  
19 replacement. For all of these reasons, the Commission approves the  
20 capital expenditures reported and projected by DTE Electric.<sup>7</sup>  
21  
22

23 **Q20. Did the Liberty Consulting Group's document titled Final Report Utility**  
24 **Distribution Audit of DTE Energy ("Audit Report") in Case No. U-21305 include**  
25 **any conclusions related to the 4.8kV Hardening Program?**

26 A20. Yes, the Audit Report did include a conclusion specific to the DTE Electric 4.8kV  
27 Hardening Program, recognizing that "[c]ompletion of the City of Detroit 4.8kV  
28 hardening program as the DGP plans is sound<sup>8</sup>." Further, the Audit Report stated,  
29 "[t]his program, which continues the removal of arc wire that formed an integral part  
30 of its institution, is nearing completion. It has improved resiliency and safety."  
31

<sup>7</sup> U-21534 - Commission Order, January 23, 2025, p. 104

<sup>8</sup> Case No. U-21305, [068cs00000AyaNpAAJ](#), Audit Report, Part Two, Chapter 2, p. 75

Line  
No.

1 **Q21. What is the status of the Company's efforts to remove the DPLD arc wire as part**  
2 **of the 4.8kV Hardening Program?**

3 A21. As outlined in Table 1 below, the Company hardened a total of approximately 1,119  
4 miles and removed a total of approximately 435 miles of arc wire between 2018 and  
5 2022.

6

7 **Table 1. 4.8kV Miles Hardened and Arc Wire Removed (2018-2022)**

| 4.8kV<br>Hardening                     | 2018<br>Actual | 2019<br>Actual | 2020<br>Actual | 2021<br>Actual | 2022<br>Actual | Total        |
|----------------------------------------|----------------|----------------|----------------|----------------|----------------|--------------|
| Miles Hardened                         | 105            | 128            | 209            | 202            | 475            | <b>1,119</b> |
| Arc Wire Miles                         | 59             | 52             | 105            | 64             | 155            | <b>435</b>   |
| Capital<br>Investment<br>(\$ millions) | \$40.3         | \$48.3         | \$55.25        | \$65.4         | \$157.5        |              |

8

9 As outlined in Table 2 below, the Company subsequently hardened approximately 373  
10 miles and 161 miles in 2023 and 2024, respectively, and removed approximately 208  
11 and 24 miles of arc wire in 2023 and 2024, respectively. Going forward, the Company  
12 estimates hardening approximately 578 miles and removing approximately 385 miles  
13 of arc wire between 2025 and 2027.



Line  
No.1           **Table 2.           4.8kV Miles Hardened and Arc Wire Removed (2023-2027)**

| 4.8kV<br>Hardening                     | 2023<br>Actuals | 2024<br>Actuals | 2025<br>Forecast | 2026<br>Forecast | 2027<br>Forecast | Total        |
|----------------------------------------|-----------------|-----------------|------------------|------------------|------------------|--------------|
| Miles Hardened                         | 373             | 161             | 260              | 259              | 59               | <b>1,111</b> |
| Arc Wire Miles                         | 208             | 24              | 142              | 231              | 12               | <b>618</b>   |
| Capital<br>Investment<br>(\$ millions) | \$130.5         | \$92.3          | \$126.1          | \$129.4          | TBD              |              |

2

3           **Q22.   Why is there a variance between miles of DPLD arc wire removed and miles**  
4           **hardened in each year of the 4.8kV Hardening Program?**

5           A22.   There are fewer miles of DPLD arc wire removed because the DPLD system does not  
6           perfectly overlap with DTE Electric's distribution system. The Company has observed  
7           that there is, on average, approximately twice as much DTE Electric distribution wire  
8           on Detroit circuits as there is DPLD arc wire.

9

10          **Q23.   Can you explain the Company's plan to address the remaining 253 miles of arc**  
11          **wire?**

12          A23.   The Company will address the remaining 253 miles of arc wire<sup>9</sup> with either the 4.8kV  
13          Hardening Program or through conversions projects, with complete removal of co-  
14          located DPLD arc wire targeted by 2030. The Company's current plan expands the  
15          scope of the Hardening Program to include an additional 38 miles of arc wire removal  
16          as compared to previous estimates of that work. As outlined in Table 3, this updated

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<sup>9</sup> U-21534 Order, p. 103: "[i]n its next electric rate case, DTE Electric is directed to present a comprehensive plan for the removal of the remaining 253 miles of arc wire."

Line  
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1 scope increases the total arc wire miles addressed by the 4.8kV Hardening Program to  
2 1,053 miles and 215 miles addressed by the conversions program.

3

4

**Table 3. DPLD Arc Wire Removal**

| Program         | Arc Wire Miles |
|-----------------|----------------|
| 4.8kV Hardening | 1,053          |
| Conversions     | 215            |
| <b>Total</b>    | <b>1,268</b>   |

5

6

7

8

9

10

11

12 **Q24. Why is the Company dividing the remaining arc wire removal between hardening**  
13 **and conversion projects?**

14

15

16

A24. The Company has determined that the decision to divide the remaining arc wire  
removal between hardening and conversion projects is the most operationally sound  
plan that avoids duplicate expense due to mobilization and demobilization. Hardening

<sup>10</sup> CODI: Islandview Substation, U-21860, Ex. A-12, Sch. B5.4, p. 12, lines 30, 35-36, and other Islandview Conversion projects detailed in the U-21297 2025 Circuit Conversion IRM Plan.

<sup>11</sup> CODI: Kent/Gibson Conversion, U-21860, Ex. A-12, Sch. B5.4, p.12, lines 73-76, and Kent/Gibson Conversion projects detailed in the U-21297 2025 Circuit Conversion IRM Plan.

<sup>12</sup> CODI: Howard Conversion, U-21860, Ex. A-12, Sch. B5.4, p. 12, line 82, and Howard Conversion projects detailed in the U-21297 2025 Circuit Conversion IRM Plan.

<sup>13</sup> 4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade), U-21860, Ex. A-12, Sch. B5.4, p. 12-13, lines 41, 48, 55, 92, 97, and Promenade Conversion projects detailed in the U-21297 2025 Circuit Conversion IRM Plan.

<sup>14</sup> 4.8 kV CC: Zenon Substation and Circuit Conversion, U-21860, Ex. A-12, Sch. B5.4, p. 12, line 59.

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1 all circuits to remove co-located arc wire would lead to some circuits being hardened,  
2 only to be converted a few years later.

3

4 **IV. The Pole and Pole-Top Maintenance and Modernization Program (“PTMM”)**

5 **Q25. What is the PTMM program?**

6 A25. The PTMM (Pole and Top Maintenance and Modernization) program is designed to  
7 inspect and maintain overhead distribution equipment to enhance system reliability and  
8 resilience against weather, storms, and tree-related events. It involves inspecting all  
9 wood poles and pole-top equipment on distribution and subtransmission overhead  
10 circuits, and replacing any that fail inspection with stronger, potentially higher-class  
11 poles and upgraded pole-top materials. These new materials, such as fiberglass  
12 crossarms and polymer insulators, offer significantly greater mechanical strength and  
13 durability, resulting in fewer equipment failures and customer outages.

14

15 Overall, the goal of the Company’s PTMM program is to inspect and maintain  
16 overhead distribution equipment in support of improving system reliability and  
17 resilience to weather, storms, and improve the safety of the system by reducing wire  
18 down events.

19

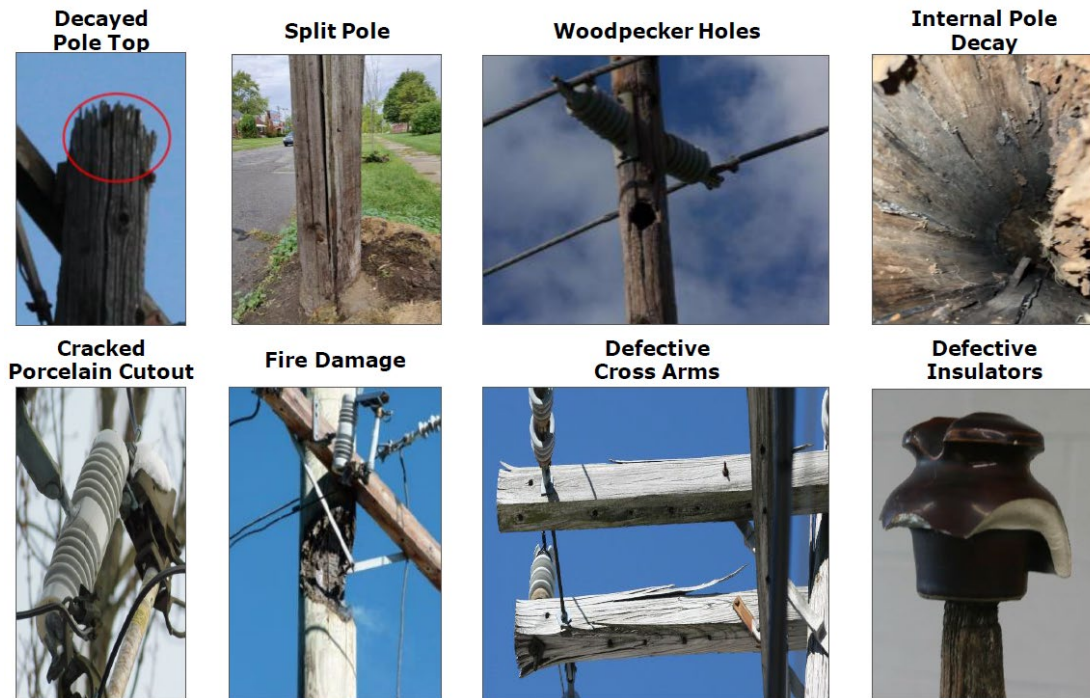
20 **Q26. What are the drivers of the Company’s PTMM program?**

21 A26. Approximately 70% of DTE Electric’s grid infrastructure is overhead, with overhead  
22 equipment failures causing approximately 25% of all outages customers experience  
23 during all weather conditions and over 30% of all outages customers experience  
24 excluding Major Event Days (“MEDs”). Poles and pole-top equipment are some of the  
25 most critical parts of the distribution and subtransmission grid, and are continually

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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 5.

**Figure 5. 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 6 displays DTE

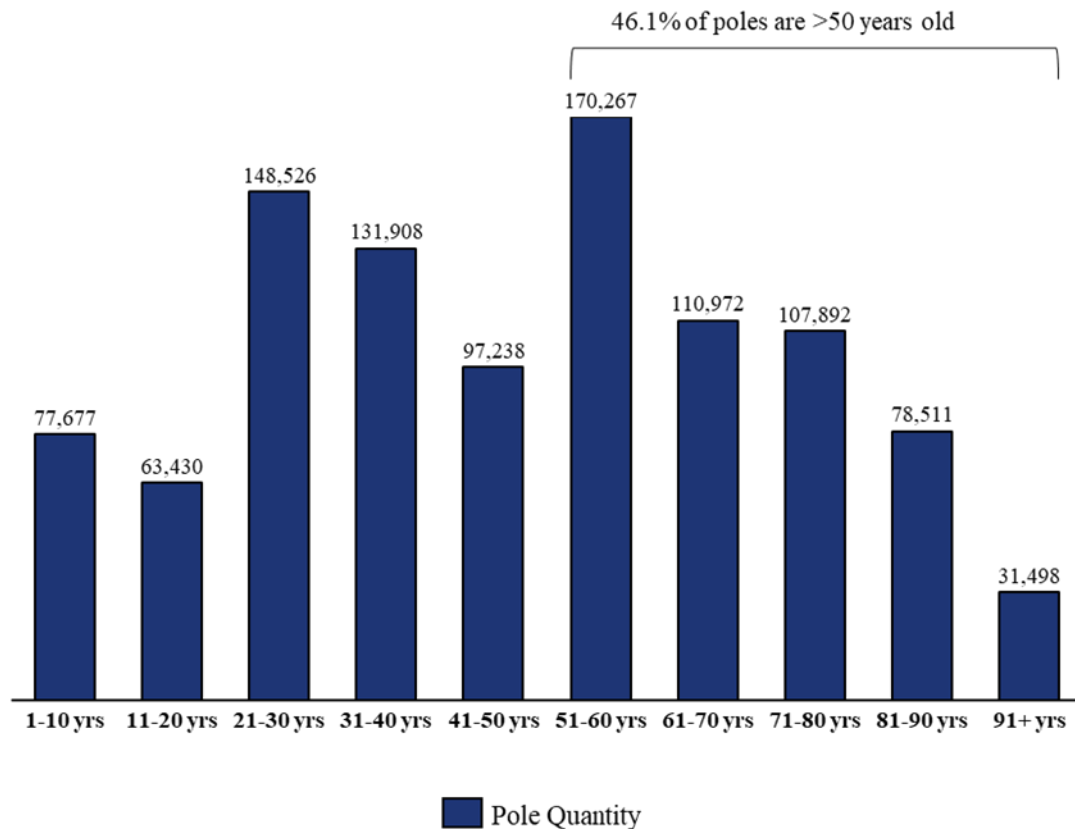
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1 Electric owned utility pole counts currently in use in the system by age range. Notably,  
2 approximately 46% of the Company's poles are more than 50 years old.

3

4

**Figure 6. DTE Electric Poles by Age**



5 Aging and defective poles and pole-top equipment increase the risk of overhead  
6 equipment failures, which can subsequently cause outages. Pole and pole-top  
7 equipment are not replaced solely because of age but based on inspection results. In  
8 addition to outages, examples of incidents that can occur in the event of pole and pole-  
9 top equipment failures include property damage, fires, and traffic accidents.  
10 Additionally, long and costly customer outages can result when this equipment fails  
11 unexpectedly from tree impacts or from other causes. Figure 7 displays an example of

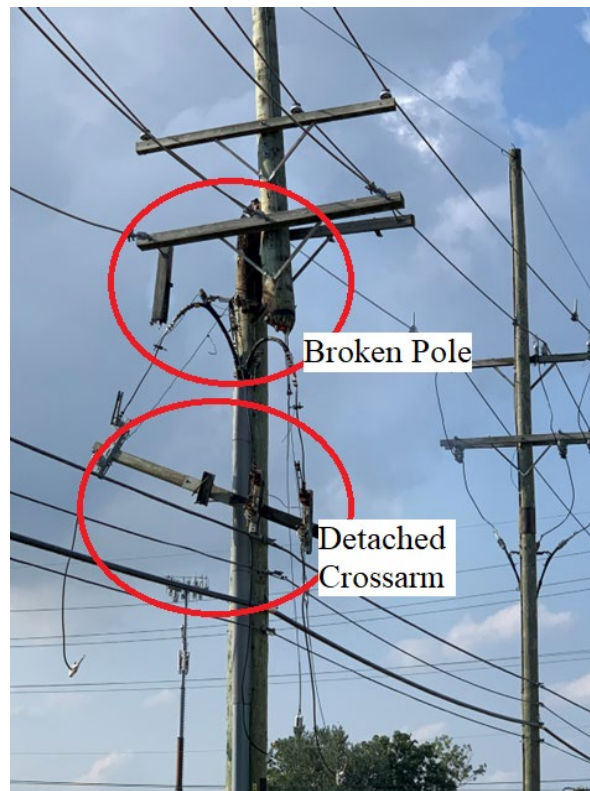
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1 a pole-top equipment failure; specifically, a break in the pole itself and a detached  
2 crossarm.

3

4

**Figure 7. Overhead Pole-top Failure – Example**



5

6 Pole and pole-top maintenance programs, like the Company's PTMM program, are  
7 standard utility industry programs that inspect circuits for damaged or defective poles  
8 and pole-top equipment, replacing them before they cause failures.

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**Q27. How has benchmarking and industry research impacted the way the Company manages its PTMM program?**

A27. The Company relied on internal engineering expertise, combined with benchmarking other Northeast and Midwest utility practices and reviewing industry standards<sup>15</sup>, to develop a goal of implementing a PTMM program capable of inspecting and completing the required construction for pole-top equipment locations on a 5-year cycle and for pole inspection (testing for structural integrity) on a 10-year cycle (the “PTMM 5- and 10-year cycles”). The Company presented the PTMM 5- and 10-year cycles to the Commission as part of Case No. U-21534. The Commission’s response is provided later in my testimony.

**Q28. What benchmarking served as the basis of the Company’s PTMM 5- and 10-year cycles?**

A28. The Company performed three benchmarking studies on peer utilities looking at PTMM practice, the most recent being in 2022. 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 inspect and address defective pole and pole-top assets in the field before they fail. Additionally, the benchmarking studies identified that the Company’s inspection standards, including the PTMM 5- and 10-year cycle, are in line with other utilities.

Table 4 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

---

<sup>15</sup> Case No. U-21860 Ex. A-23, Sch. M13

Line  
No.

1 operate on a 10-year (or less) cycle time for pole inspections and construction, and a 5-  
2 year cycle time for pole-top inspections and construction.

3

4

**Table 4. PTMM Benchmarking**

| Company<br>(Location) | Pole Inspection<br>Cycle (Years) | Pole-Top Inspection<br>Cycle (Years) |
|-----------------------|----------------------------------|--------------------------------------|
| #1 (Northeast)        | 10                               | 4                                    |
| #2 (Northeast)        | 5                                | 5                                    |
| #3 (Midwest)          | 10                               | 5                                    |
| #4 (Midwest)          | 10                               | 5                                    |
| #5 (Midwest)          | 10                               | 5                                    |
| #6 (Midwest)          | 12                               | 12                                   |
| #7 (Midwest)          | 8-12                             | 8-12                                 |

5

6

7

8

9

10 **Q29. Did the Commission address the PTMM program in Case No. U-21534?**

11 A29. Yes, the Commission approved cost recovery of PTMM for 2025 in Case No. U-21534  
12 but acknowledged that the Audit Report (Case No. U-21305) was likely to affect the  
13 analysis of this expenditure category in the next rate case. In the Order, the  
14 Commission noted that the “BCA demonstrates the PTMM produces positive results,”

---

<sup>16</sup> Case No. U-21860, Ex. A-23, Sch. M13



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1 and that the “Commission supports these work activities.”<sup>17</sup> The Audit Report  
2 recommendation is provided later in my testimony.

3 **Q30. Did the Commission provide guidance on an appropriate cycle for PTMM in Case**  
4 **No. U-21534?**

5 A30. Yes, the Commission stated that “[i]n the company’s next rate case, [it] expects to see  
6 progress in DTE Electric’s goal of reaching the 5-year and 10-year cycles ‘utilizing the  
7 reliability tier model and BCA output, to select the optimal mix of circuits to improve  
8 customer reliability’ to match the industry standards that the company has identified  
9 through its benchmarking efforts.”<sup>18</sup>

10

11 **Q31. Did the Audit Report provide guidance on an appropriate cycle for PTMM?**

12 A31. Yes. The Audit recommended the Company “adopt a four-to-five-year visual overhead  
13 inspection program, focusing on securing visual control of the system and adjusting  
14 repair/replacement scope in the first cycle to account for what can be expected to be  
15 very high first-cycle costs.”<sup>19</sup> The Company understands this recommendation as  
16 applicable to the visual inspection of pole and pole-top portion of the PTMM program.

17

18 **Q32. How did the Company respond to the Audit Report’s recommendation for a four-**  
19 **to-five-year overhead circuit inspection program?**

20 A32. In DTE Electric’s Implementation Plan for the Audit, the Company “agree[d] with the  
21 recommendation to target more frequent visual inspection of the overhead electrical

---

<sup>17</sup> Case No. U-21534 - Commission Order, January 23, 2025, p. 108

<sup>18</sup> Case No. U-21534 - Commission Order, January 23, 2025, p. 108

<sup>19</sup> Case No. U-21305, [068cs00000AyaNpAAJ](#), Audit Report, Part Two, Chapter 1, p. 43

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1 system. The Company will evaluate the scope, cost, and reliability impacts of shifting  
2 the target cycle to four-to-five years.<sup>20</sup>

3

4 **Q33. What changes has the Company made to the PTMM program to address the Audit**  
5 **Report’s recommendation for a more frequent four-to-five-year cycle for visual**  
6 **overhead inspections?**

7 A33. In response to the Audit Report’s recommendation, as well as in an effort to reach the  
8 Company’s goal of PTMM 5-year and 10-year cycles, the Company identified two  
9 main updates for the PTMM program in this proceeding.

10

11 First, beginning in 2026, the Company will begin increasing the frequency of pole and  
12 pole-top inspections to provide more timely identification of potential failure  
13 conditions. As part of the inspections, the Company will develop a pole-top hazard  
14 patrol that will rank issues identified during pole-top inspections into three categories:  
15 (1) safety or imminent outage; (2) outage or failure likely; and (3) future attention  
16 required. For those pole-tops with an issue categorized as “safety or imminent outage,”  
17 the Company will complete the repair as soon as possible. Examples of issues  
18 considered “safety or imminent outage” include, among others, broken poles;  
19 transformer leaking oil; and floating neutral and floating conductors. For those pole-  
20 tops with an issue categorized as “outage or failure likely,” the Company will complete  
21 the repair within the PTMM program, meaning it will be included in the scope for  
22 replacement during the current-year PTMM program. Examples include, broken,  
23 cracked, or disconnected pole top equipment; holes on cross-arms; and poles with  
24 significant rotting. And the last category, “future attention required,” means the issue

---

<sup>20</sup> Case No. U-21305, DTE Electric Company Implementation Plan for the DTE Electric Audit Report, p. 22.

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1 will be logged for re-inspection on the next cycle. The issues in this category are not  
2 included in the scope for replacement during the current-year PTMM program.  
3 Examples include porcelain cutouts that do not show signs of damage; cracked or rotted  
4 pole tops that do not have pole top equipment that needs to be replaced; and leaning  
5 poles.

6

7 Second, the Company will allocate available funding to achieve near-term benefits  
8 while also working to expand program funding to achieve the desired goal of the  
9 PTMM 5-year and 10-year cycles by 2029. For the goal of a 10-year inspection cycle  
10 for poles (*i.e., groundline pole inspection*), the Company will use its pole inspection  
11 specification<sup>21</sup> focused on ground line and structural integrity of the poles themselves  
12 in the near-term. For the goal of a 5-year inspection cycle for pole-tops, overhead lines,  
13 and associated equipment, the Company will use its pole top equipment inspection  
14 specification,<sup>22</sup> described above which will increase the frequency of inspection cycles  
15 to provide a more frequent assessment of the condition of the overhead system.

16

17 **Q34. What is the scope of the groundline pole inspection and maintenance portion of**  
18 **the PTMM program?**

19 A34. The Company's system has approximately 31,000 miles of overhead infrastructure that  
20 would be covered as part of the groundline pole inspection and maintenance portion of  
21 the PTMM program. To achieve a 10-year cycle, the Company plans to ramp up to  
22 inspect 3,100 miles/year. Groundline Pole Inspections will be performed as  
23 summarized below:

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<sup>21</sup> Case No. U-21860, Ex. A-23, Sch. M9 – Wood Pole Maintenance Specification

<sup>22</sup> Case No. U-21860, Ex. A-23, Sch. M10 – Pole-Top Maintenance Specification

Line  
No.

1        Pole Inspection and Maintenance Activities:

2                    1. Inspecting poles for damage that will undermine structural integrity.

3                    (a) Poles installed within the last 20 years are visually inspected above  
4                    grade.

5                    (b) Poles older than 20 years are visually inspected and excavated below  
6                    grade level and physically tested.

7                    2. Treating, reinforcing or replacing poles that fail inspection;

8                    3. Trimming trees, as required.

9

10        **Q35. What is the scope of the pole-top inspection and maintenance portion of the**  
11        **PTMM program?**

12        A35. To achieve a 5-year cycle, the Company plans to ramp up to inspect 6,700 miles/year.  
13        Pole-top inspection will be performed as summarized below:

14

15        Pole-top Inspection and Maintenance Activities:

16                    1. Visually inspecting pole-tops and pole-top equipment for damaged and/or  
17                    defective equipment;

18                    2. Replacing pole-top equipment that fails inspection, with a higher-grade  
19                    material, for example:

20                    (a) Damaged wooden crossarms are replaced with fiberglass crossarms.

21                    (b) Damaged/defective porcelain cutouts are replaced with polymer  
22                    cutouts.

23                    (c) Damaged/defective porcelain insulators are replaced with polymer  
24                    insulators.

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1                   3. Performing infrared inspections to identify conductor "hot spots" that can  
2                   cause thermal degradation and potential thermal runaways. This condition,  
3                   where an increase in temperature leads to higher power consumption and  
4                   further temperature increases in a self-reinforcing cycle, can be a key  
5                   indicator of potential conductor failure.

6

7       **Q36. What investment levels will be necessary to achieve the PTMM 5-year and 10-year**  
8       **cycles?**

9       A36. The PTMM program is currently funded, in 2025, with approximately \$121 million,  
10       which will cover approximately 1,200 miles of both pole-top and groundline pole  
11       maintenance. In the instant case, the Company is requesting an increase to \$200 million  
12       for 2026. To fund pole-top and groundline pole maintenance on the 5-year and 10-year  
13       cycles, the Company anticipates a peak investment of approximately \$438 million in  
14       2025 dollars.

15

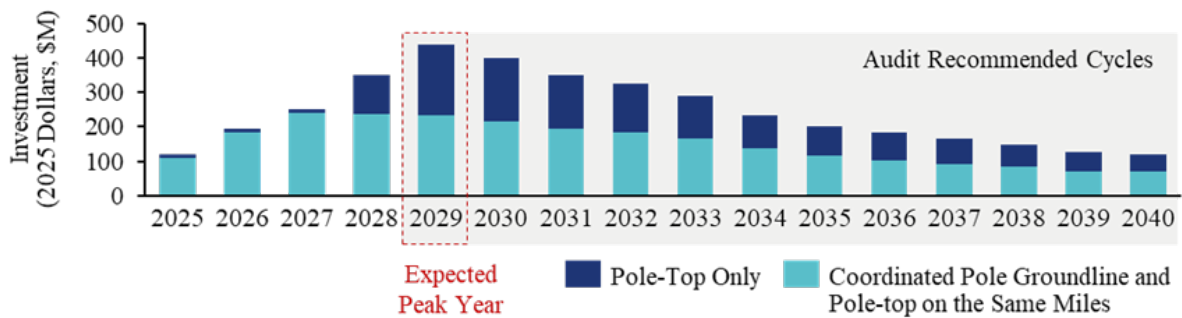
16       **Q37. What is the Company's plan to meet the PTMM 5-year and 10-year cycles?**

17       A37. As shown in Figure 8 below, the Company developed a ramp-up plan to meet the  
18       PTMM 5-year and 10-year audit recommended cycles. Using system-wide averages  
19       based on the PTMM BCA, the Company anticipates reaching audit recommended  
20       cycles by 2029. The overall annual investment level is anticipated to decrease as  
21       circuits begin the second and subsequent cycles. Investment will continue to decrease  
22       until all circuits are on a 5-year pole-top cycle. This aligns with the Audit Report that  
23       states, "[i]t also needs to be recognized that work, and therefore costs per year on a  
24       four-year cycle, will be higher. However, once having addressed the entire system, this  
25       cycle will lead to much reduced costs for the following years. Over time, a shorter cycle

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1 will not produce greater work. However, it will remove damaged and deteriorated poles  
2 and equipment more timely from the system and reduce restoration costs.”<sup>23</sup>  
3

4 **Figure 8. PTMM Groundline Pole and Pole-Top Maintenance Investment Levels**



5

6 **Q38. Does the Company anticipate that the investment levels to sustain the 5-year and**  
7 **10-year distribution cycles at fully funded levels will remain constant once those**  
8 **cycles are met?**

9 A38. No. The Company anticipates that the investment levels associated with sustaining the  
10 5-year pole-top and 10-year groundline pole distribution inspection cycles, once met,  
11 will decrease after the first and second cycles due to failure rates going down as  
12 inspections and repairs are completed (Figure 8). Note that Figure 8 shows forecasted  
13 investment in 2025 dollars without inflation adjustments.  
14

15 **Q39. How does the Company prioritize circuits for the PTMM program?**

16 A39. The Company is using the PTMM BCA, as described by Witness De Stigter, to  
17 prioritize work. Specifically, the BCA data was prioritized by: (1) focusing on circuits  
18 that were trimmed recently to optimize the required program trimming; (2) applying an  
19 EJ multiplier to benefit-cost ratio (BCR) by circuit; (3) sorting the BCR high-to-low;

<sup>23</sup> Case No. U-21305, [068cs00000AyaNpAAJ](#), Audit Report, Part Two, Chapter 1, p. 43

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1 (4) balancing workload between regions; (5) filtering circuits that were hardened or  
2 recently addressed by the PTMM program; and then (6) selecting all circuits on a  
3 selected substation area for operational efficiency. Using this methodology, the  
4 Company will leverage the PTMM BCA information to prioritize work while  
5 accelerating investment to meet the 5-year and 10-year cycles as described above.

6

7 **Q40. What are the BCA analysis results for the PTMM program?**

8 A40. Company Witness De Stigter comprehensively evaluated the groundline pole portion  
9 of the Company's PTMM program across the entire DTE Electric overhead distribution  
10 system. This analysis and its results are summarized in Witness De Stigter's Exhibit  
11 A-28, Schedule R3. It was determined that if the groundline pole portion of the PTMM  
12 program were applied to the entire overhead distribution system, the overall investment  
13 level would be approximately \$1.66 billion. The aggregate benefit-cost ratio (BCR) for  
14 deploying the groundline pole portion of the program was determined to be 1.69 for  
15 the entire overhead distribution system, providing a customer benefit of approximately  
16 \$2.81 billion.

17

18 Similarly, Witness De Stigter comprehensively evaluated the pole-top portion of the  
19 Company's PTMM program across the entire DTE Electric overhead distribution  
20 system. It was determined that if the pole-top portion of the program were applied to  
21 the entire overhead distribution system, the overall investment level would be  
22 approximately \$709 million. The aggregate BCR for deploying the pole-top portion of  
23 the program was determined to be 2.76 for the entire overhead distribution system,  
24 providing a customer benefit of approximately \$1.96 billion.

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1 As indicated in the Witness De Stigter’s BCA report (Exhibit A-28, Schedule R3), a  
2 key benefit not included in the benefit-cost analysis is the mitigation of safety risks.  
3 Broken poles and wire downs pose a potential risk to crews and the public. The PTMM  
4 program reduces both of these potential risks, enhancing safety. Additionally, the  
5 program improves reliability by reducing outages and resiliency by strengthening the  
6 infrastructure against severe weather conditions, further justifying this investment.  
7 For further information on the BCA analysis for the PTMM program, please see  
8 Company Witness De Stigter’s testimony and Exhibit A-28, Schedule R3.

9

10 **Q41. What PTMM work did the Company complete in 2024?**

11 A41. DTE Electric completed inspection and construction in excess of 850 circuit miles  
12 which included approximately 6,300 pole-top equipment locations and replaced just  
13 under 3,400 poles. Additionally, the program completed inspections on about 38,000  
14 poles—with approximately 10,000 physical inspections and 28,000 visual inspections.

15

16 **Q42. What is the status of the PTMM program work ready for construction?**

17 A42. As of the beginning of 2025, the Company had approximately 1,900 poles and 9,700  
18 pole-top locations that failed inspection and still require construction to be completed.

19

20 **Q43. What is in the Company’s 2025 and 2026 PTMM workplan?**

21 A43. Case No. U-21534 approved investment of \$121 million in the PTMM program.<sup>24</sup> This  
22 investment will fund the 2025 workplan, which includes the replacement of poles and  
23 pole-top equipment across approximately 1,340 circuit miles. This translates to  
24 replacing approximately 6,150 poles and replacing pole-top equipment that has failed

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<sup>24</sup> Case No. U-21534 Order, p. 108



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inspection at approximately 6,360 locations. In this instant case, the Company is requesting \$200 million for 2026 in the PTMM program to replace poles and pole-top equipment on approximately 2,000 circuit miles. This translates to replacing approximately 9,090 poles and replacing pole-top equipment that has failed inspection at approximately 10,720 locations, as shown in Table 5.

**Table 5. PTMM 2025-2026 Workplan**

|                                  | 2025    | 2026    |
|----------------------------------|---------|---------|
| Circuit Miles                    | 1,340   | 2,000   |
| Poles Replaced                   | 6,150   | 9,090   |
| Poles Reinforced                 | 1,440   | 2,410   |
| Pole-Top Locations Replaced      | 6,360   | 10,720  |
| Capital Investment (\$ millions) | \$121.0 | \$200.0 |

**Q44. Has the Company determined the O&M expenses associated with the PTMM program?**

A44. Yes. The Company anticipates an incremental approximately \$10.5 million will be needed to support the 2026 O&M work associated with Groundline Pole and Pole-Top inspections.<sup>25</sup>

<sup>25</sup> Case No. U-21860, Ex. A-13, Sch. C5.6, page 2.

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1 **Q45. What are the Company's expectations for investment in PTMM beyond the**  
2 **projected test year?**

3 A45. The Company will need to continue to invest in PTMM beyond the test period covered  
4 in this case. The forecast of required investment<sup>26</sup> beyond 2026 is:

- 5 • 2027: \$263.4 million
- 6 • 2028: \$376.8 million
- 7 • 2029: \$482.6 million

8 This reflects the full expected capital investment for the PTMM program from 2027 to  
9 2029 and is included in this case as the basis for the Company's IRM request supported  
10 by Company Witness Willis. The PTMM circuit prioritization in the IRM will follow  
11 the method mentioned earlier in my testimony, which includes using the EJ multiplier  
12 to adjust the BCR.

13

14 **V. Small Wire Replacement Program**

15 **Q46. What is the Small Wire Replacement Program?**

16 A46. The Small Wire Replacement program is a new program that will begin in 2026, and  
17 was created in response to the Audit Report's recommendation that the Company  
18 expand mitigation of wire downs to include a more near-term proactive prevention.  
19 While programs such as Hardening and PTMM focus on the pole and pole top  
20 infrastructure, replacing wire has in the past been performed either in full circuit  
21 conversions, or on an emergent basis when wires failed during storms or other events.  
22 The Small Wire Replacement program will target wire on 4.8kV circuits with a high  
23 volume of primary wire down events. Small primary wire, where "small" is a reference  
24 to the diameter of the wire and is inherently able to carry less load, is typically found

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<sup>26</sup> The costs stated below have been adjusted for inflation. The program's peak investment cited earlier in this testimony is stated in 2025 dollars.

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1 on the laterals (or ends) of circuits where large conductor was not originally needed  
2 due to lower loading. Because of the aged infrastructure on many of our 4.8kV circuits,  
3 pole and crossarm replacement will likely be needed to support the larger conductor  
4 replacement. Circuits will be prioritized by the number of wire downs experienced in  
5 the past.

6 **Q47. What are the drivers for replacing small gauge wire?**

7 A47. Small primary wire is any wire conductor smaller than gauge 1/0 type that is non-ACSR  
8 (Aluminum Conductor Steel reinforced) that operates at a line-to-line voltage above  
9 1000kV. These smaller conductor types were a typical gauge used when older circuits  
10 were installed decades ago and are more prone to wire downs during inclement weather  
11 and tree contacts, and are not consistent with current standards. For example, the  
12 Company's system currently has approximately 2,900 miles of #6 Copper small wire,  
13 which accounts for only 9% of the Company's total conductor but contributes to 39%  
14 of the total wire downs.

15

16 **Q48. What are the benefits of replacing small gauge wire?**

17 A48. Replacing small gauge wire with larger gauge wire offers several benefits. Larger  
18 gauge wires help reduce wire downs, minimizing disruptions and maintenance costs,  
19 and reduce safety risks to the infrastructure and the public. Additionally, larger gauge  
20 wires can carry more current, reducing the risk of overheating. Thicker wires are less  
21 prone to damage and can handle higher loads, enhancing the overall reliability and  
22 capacity of the electrical system. Additionally, larger wires have lower resistance,  
23 which means less energy is lost as heat, improving the efficiency of the electrical  
24 system. Furthermore, the current standard ACSR conductor, such as 1/0ACSR and

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1 336.4ACSR, have a much higher mechanical strength and lower failure rates than  
2 smaller, non-ACSR conductor. By reducing the risk of overheating and wire failure,  
3 larger gauge wires also contribute to a safer electrical infrastructure. As the Company  
4 replaces miles/circuits of small wire, it plans to gather data to estimate the reliability  
5 benefits on a per mile/circuit basis.

6 **Q49. How much small gauge wire exists on the Company's system that is being targeted**  
7 **with this program?**

8 A49. The Company intends to target 5-20 miles of the approximately 3,600 total miles of  
9 small gauge wire for replacement in the first year of the program.

10

11 **Q50. What investment is required in the instant case to support the Small Wire**  
12 **Replacement Program?**

13 A50. To fund the Small Wire Replacement program, which plans to replace 5-20 miles of  
14 small gauge wire in 2026, the Company anticipates needing an investment of  
15 approximately \$10 million in 2026 projected test year.

16

17 **Q51. Does the Company have a timeline for the Small Wire Replacement Program?**

18 A51. Not at this time. The Company is initiating the program at a modest pace to gain insight  
19 into the time required to replace the small wire on the system. This will help achieve  
20 maximum benefits before scaling up to more concerted efforts in the coming  
21 years. This approach aims to achieve the maximum benefit of reducing wire downs,  
22 optimizing the program, and improving reliability.

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1     **Q52. What happens if the Company does not replace small gauge wire?**

2     A52. If the Company does not replace small gauge wire, several negative consequences  
3         could arise. Small gauge wires are more prone to overheating, especially under higher  
4         loads, which can lead to potential damage to the electrical system. They are less  
5         durable and more likely to fail during storms or other adverse conditions, resulting in  
6         more frequent outages and wire down incidents. This can reduce the overall reliability  
7         of the electrical system, leading to more interruptions and longer repair times.  
8         Additionally, smaller wires have higher resistance, meaning more energy is lost as heat,  
9         reducing the efficiency of the electrical system and potentially increasing operational  
10        costs. Replacing small gauge wire improves safety, reliability, and distribution system  
11        efficiency.

12

13     **VI. Preventative Maintenance (“PM”) Program**

14     **Q53. What is the PM program?**

15     A53. The Company’s PM program encompasses inspection of selected overhead equipment,  
16         underground, and substation assets, netbank structure inspections and repairs, and  
17         structural testing activities. It has three primary objectives: (1) Control or reduce  
18         equipment-related outages, (2) Maximize the total life expectancy of the equipment at  
19         minimum lifecycle cost while maintaining safety and reliability, and (3) Acquire timely  
20         asset performance and condition data to support trend data analysis and identify  
21         potential issues.

22

23         DTE Electric Engineering developed the program based on DTE Electric’s  
24         maintenance policies, which set inspection scope and intervals based on manufacturer’s  
25         recommendations, industry standards and best practices, historical inspection results

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1 and equipment condition data, engineering studies, and benchmarking with utility  
2 peers.

3

4 The Company continues to refine its maintenance policies in order to find efficiencies  
5 and reduce failures. Some examples of the continuous improvement integrated into the  
6 PM program are:

7 • Changing inspection intervals based on engineering analyses of inspection  
8 results and equipment failures (condition-based maintenance).

9 • Using substation predictive maintenance (SPdM) data to drive inspection  
10 timelines instead of time-based inspections, to be aligned with condition-  
11 based maintenance principles and to achieve cost efficiency.

12 • Reducing maintenance activities by using new technologies (e.g., smart  
13 relays).

14 • Coordinating inspection intervals on different equipment to reduce the need  
15 for multiple shutdowns.

16

17 The Company's PM program is essential to minimizes unplanned outages,  
18 maintaining reliable service and extending equipment life. This program improves  
19 performance, reduces the need for frequent replacements, and prevents premature  
20 failures, enhancing overall system efficiency and reliability. Preventive maintenance  
21 is cost-effective, avoiding the higher expenses of emergency repairs and downtime.  
22 By collecting performance and condition data, it enables better analysis and proactive  
23 decision-making. It also addresses potential safety hazards before they become  
24 serious, maintaining a safe working environment and protecting the community.

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1           Additionally, preventive maintenance lowers reactive costs by avoiding expensive  
2           unplanned outages and urgent repairs, as I discuss later in my testimony.

3

4       **Q54. What equipment is included in the Company's PM program?**

5       A54. DTE Electric's preventive maintenance program categorizes equipment into three  
6           groups: (1) substations, (2) overhead equipment, and (3) underground, as shown in  
7           Tables 6 – 8 below.

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1

**Table 6. Preventative Maintenance Activities – Substations**

| Asset                                    | Population<br>(approx.) | General Inspection<br>Cycle (years) |
|------------------------------------------|-------------------------|-------------------------------------|
| 120kV disconnects                        | 352                     | 10                                  |
| 120kV breakers                           | 32                      | 10/12                               |
| 24/40kV breakers                         | 1,055                   | 3/10/12                             |
| Distribution breakers                    | 5,381                   | 3/10/12                             |
| Buses                                    | 244                     | 10                                  |
| Regulators                               | 249                     | 10                                  |
| Portable substations                     | 10                      | 1                                   |
| Single tap substations                   | 112                     | 10                                  |
| 13.2kV capacitor banks                   | 231                     | 1                                   |
| AC netbank transformers                  | 505                     | 5                                   |
| AC netbank structures                    | 384                     | 10                                  |
| DC systems                               | 651                     | 1                                   |
| Dissolved gas analysis (DGA)             | 3,345                   | 1                                   |
| Substation predictive maintenance (SPdM) | 1,640                   | 3                                   |
| Voltage control periodics                | 1,717                   | 1                                   |
| Relay periodics                          | 9,887                   | 5/7/10                              |



Line  
No.1                      **Table 7.            Preventative Maintenance Activities – Overhead**

| Asset                                       | Population<br>(approx.) | General Inspection<br>Cycle (years) |
|---------------------------------------------|-------------------------|-------------------------------------|
| 40kV pole top switches                      | 868                     | 8                                   |
| Distribution remote devices                 | 1,894                   | 4/8                                 |
| OH capacitor & regulator controls           | 6,150                   | 1                                   |
| OH distribution device battery replacements | 1,894                   | 4                                   |
| Towers                                      | 500                     | 10                                  |
| DTEE equipment in high rise structures      | 52                      | 20                                  |

2                      **Table 8.            Preventative Maintenance Activities – Underground**

| Asset                       | Population<br>(approx.) | General Inspection<br>Cycle (years) |
|-----------------------------|-------------------------|-------------------------------------|
| Primary switch cabinets     | 1,914                   | 5/10/15                             |
| Manholes                    | 18,610                  | 10                                  |
| URD Padmounted Transformers | 148,180                 | 10                                  |
| Vaults                      | 13                      | 2                                   |

3

4                      **Q55.    How does the PM program benefit DTE Electric customers?**

5                      A55.    DTE Electric's PM program provides the following customer benefits:

- 6                      • Reduced unplanned outages: By performing regular maintenance, the
- 7                                      likelihood of unexpected equipment failures is minimized, providing more
- 8                                      reliable service.
- 9                      • Extended equipment life and improved performance: Regular maintenance
- 10                                      helps in maximizing the lifespan of equipment, thereby reducing the need for

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frequent replacements. Without regular maintenance, equipment is more likely to perform poorly or fail prematurely. This can lead to decreased efficiency and reliability, impacting overall system performance.

- Cost efficiency: Preventive maintenance is generally more cost-effective than reactive maintenance, as it helps avoid the higher costs associated with emergency repairs and downtime.

- Data-driven decisions: Collecting performance and condition data allows for better analysis and proactive decision-making.

- Avoiding safety hazards: Equipment failures can lead to unsafe conditions. Preventive maintenance helps identify and address potential issues before they become serious hazards, maintaining a safe working environment and protecting the community.

- Decreased trouble costs: Unplanned outages and emergency repairs can be significantly more expensive than scheduled maintenance. Preventive maintenance often results in lower costs as it tends to avoid urgent repairs and the potential need for more extensive repairs or replacements.

**Q56. Is the Company currently meeting the general inspection cycles listed in Tables 6 – 8 above?**

A56. No. The Company currently has an inspection and maintenance backlog.<sup>27</sup> Adherence to the PM inspection cycles generally have not been met, which is the primary cause of maintenance backlogs. The Company's plan to address this is to increase PM inspections to align with stated inspection cycles, which will require an incremental \$7.3 million O&M annually.

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<sup>27</sup> Case No. U-21305, [068cs00000AyaNpAAJ](#), Audit Report, Part Two, Chapter 1, pp. 44-45

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1 **Q57. What categories of maintenance activities make up the maintenance backlog?**

2 A57. The maintenance backlog includes two categories of maintenance: (1) Preventative  
3 Maintenance (“PM”) and (2) Corrective Maintenance (“CM”). PMs are past due  
4 inspections and routine maintenance, as defined in Tables 6-8. CM, in contrast,  
5 includes damaged or defective electrical or structural system equipment that needs to  
6 be repaired or replaced.

7

8 **Q58. Has the Company determined the cost to complete the CM backlog?**

9 A58. Yes, the Company determined that the cost to complete the CM backlog as of  
10 December 15, 2024, is \$7.3 million in O&M expenses, and \$23.5 million in reactive  
11 capital.

12

13 **Q59. What is the Company requesting in the instant case related to the CM backlog?**

14 A59. To implement the Company’s plan to reduce the CM backlog, the Company requires  
15 an incremental \$7.3 million in O&M for 2026,<sup>28</sup> and \$23.5 million in reactive capital.<sup>29</sup>

16

17 **Q60. Did the Audit Report include recommendations related to the PM program?**

18 A60. The Audit Report included general recommendations related to the Company  
19 addressing its inspection and maintenance backlog.<sup>30</sup> Relative to the PM program  
20 scope, the Audit Report included the following four recommendations:

21 1) “Provide the resources to reduce the padmount transformer inspection  
22 backlog and determine an optimum inspection cycle...., 2) Complete manhole

<sup>28</sup> Case No. U-21860, Ex. A-13, C5.6, p. 2, Note 6.

<sup>29</sup> Case No. U-21860, Ex. A-12, B5.4, p. 3, Lines 17 & 26, column (h).

<sup>30</sup> Case No. U-21305, [068cs00000AyaNpAAJ](#), Audit Report, Part Two, Chapter 1, pp. 44-45.

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1 inspections on the established cycle, 3) Clear SCADA device backlogs...., 4)

2 Evaluate the cyclical conduct of substation infrared and oil testing.”<sup>31</sup>

3

4 **Q61. How did the Company respond to the Audit Report’s four recommendations**  
5 **related to the PM program?**

6 A61. DTE Electric will address inspection backlogs for padmount transformers, SCADA  
7 devices, and manholes by targeting annual inspections of 10% of each asset type to  
8 achieve a 10-year cycle. The Company plans to request funding in future rate cases to  
9 sustain this cycle. Additionally, DTE Electric is conducting routine oil testing for  
10 power transformers and evaluating further testing methods for substation equipment.  
11 Specific to the manhole inspection backlog, the Company agreed to complete  
12 inspections on the established 10-year cycle, but it does not agree that there is an  
13 underlying safety concern associated with that backlog, as the Company’s standard  
14 practice requires an inspection before any entry into a manhole.

15

16 **Q62. What is DTE Electric’s plan to reduce the overall PM backlog?**

17 A62. The Company is targeting a two-pronged approach to address the PM backlog. First,  
18 the Company is targeting completion of one-third of the PM backlog annually over the  
19 next three years, second, the Company will increase PM in the amount consistent with  
20 the target maintenance cycles.

21

22 **Q63. Has the Company determined the cost to complete the PM inspection backlog?**

23 A63. Yes. The Company determined that the total cost to complete the PM inspections  
24 backlog as of December 15, 2024, is \$15 million, covering approximately 109,000

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<sup>31</sup> Case No. U-21305, [068cs00000AyaNpAAJ](#), Audit Report, Part Two, Chapter 1, pp. 44-45.

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1 units. The cost to complete one-third of this backlog is an incremental \$5.0 million  
2 annually, covering approximately 36,300 units, to catch up in a 3-year timeframe.  
3

4 **Q64. Has the Company determined the cost to increase PM in amount consistent with**  
5 **target maintenance cycles?**

6 A64. Yes. DTE Electric determined that the cost to increase PM in amount consistent with  
7 target maintenance cycles is approximately an incremental \$7.3 million annually.  
8

9 **Q65. What is the Company asking for in the instant case related to the PM program?**

10 A65. To implement the plan to reduce the PM backlog and increase PM in amount consistent  
11 with target maintenance cycles, the Company requires an incremental \$7.3 million in  
12 O&M for 2026.<sup>32</sup>  
13

14 **VII. System Equipment Replacement Program**

15 **Q66. What is System Equipment Replacement?**

16 A66. System equipment as covered in this program is a subset of equipment critical to grid  
17 integrity, and which is not replaced in other programs, such as the PTMM and 4.8kV  
18 Hardening Programs. System equipment, including system cable, URD cable, and  
19 breakers, plays a vital role in delivering electricity to customers, isolating and locating  
20 faults, and maintaining proper voltages and power quality on the Company's electric  
21 system. For the grid to operate reliably, this critical system equipment not only needs  
22 to be in good working condition but also needs to be able to withstand stresses from  
23 the expected system faults. Therefore, the Company routinely monitors system

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<sup>32</sup> Case No. U-21860 Ex. A-13, C5.6, p. 1

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1 equipment to ensure it operates effectively, and if it is not, replaces it pursuant to the  
2 System Equipment Replacement program.

3

4 **Q67. How does the Company monitor and prioritize System Equipment Replacements?**

5 A67. DTE Electric uses an asset health analysis to routinely monitor and prioritize  
6 investments in the System Equipment Replacement program and identify the  
7 equipment that requires replacement. The life expectancy of system equipment is based  
8 on a combination of manufacturer recommendations, industry benchmarks, Electric  
9 Power Research Institute (“EPRI”) Industry Database, National Electric Energy  
10 Testing, Research & Applications Center (“NEETRAC”) Asset Survival Plots, and  
11 DTE Electric’s experience. The purpose of the asset health assessments is to gather  
12 information related to the Company’s assets and proactively address any identified  
13 equipment issues.

14

15 While age of equipment is not the only factor the Company considers when performing  
16 a health assessment, it can become a significant factor when replacement parts become  
17 unavailable or in the specific cases where asset health deteriorates sharply with age.  
18 Other factors such as manufacturer or equipment types that have known issues and  
19 elevated failure rates are also considered.

20

21 The result of the Company’s asset health analysis is a ranking or score for the  
22 equipment and assessment results are grouped into four categories of failure potential:  
23 acceptable, elevated, high, and severe. Equipment with a “severe” asset health  
24 assessment ranking is at the highest probability of failure and must be replaced in the  
25 near-term to maintain safe and reliable operation.

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1 Table 9 below shows the current replacement rates for assets near the end of life for  
2 established programs:

3

4

**Table 9. System Equipment Replacement Rates**

| Program      | Units near end-of-life | Annual Units Replaced | Replacement Rate (years) |
|--------------|------------------------|-----------------------|--------------------------|
| System Cable | 1,980 miles            | 11 miles              | 189                      |
| URD Cable    | 4,500 miles            | 54 miles              | 83                       |
| Breakers     | 3,600                  | 29                    | 124                      |

5

6 **Q68. Did the Audit Report include a recommendation related to System Equipment**  
7 **Replacement?**

8 A68. Yes, the Audit Report recommended the Company “[r]eplan and prioritize System  
9 Equipment Replacement investments to extend their completion by five years.”<sup>33</sup>

10

11 **Q69. How would the Audit Report recommendation impact the Company’s existing**  
12 **plan for the completion of System Equipment Replacements?**

13 A69. First, the Company’s existing plan for System Equipment Replacement consists of  
14 standard asset replacement required to renew the electrical infrastructure over the  
15 course of time, meaning there is no “completion” to the replacements in this program.

16

17 Moreover, while there are replacements of the current Distribution Grid Plan (DGP)  
18 for system cable, breakers, and Underground Residential Distribution (URD) proposed  
19 in the five-year horizon due to their “severe” asset health assessment ranking, those

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<sup>33</sup> Case No. U-21305; Audit Report, Part Two, Chapter 1, p. 77.

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1 replacements are just a small fraction of the overall need on the system. As I explained  
2 earlier in my testimony, System Equipment plays a vital role in delivering electricity  
3 to customers, isolating and locating faults, and maintaining proper voltages and power  
4 quality on the electric system. For the grid to operate reliably, this critical system  
5 equipment not only needs to be in good working condition but also needs to be able to  
6 withstand the stresses from the inevitable system faults. For these reasons, the  
7 Company respectfully disagrees with the Audit Report's recommendation to extend  
8 completion of those investments by five years.

9  
10 **Q70. What are the potential risks and consequences of extending the completion of the**  
11 **System Equipment Replacement by five years as recommended in the Audit**  
12 **Report?**

13 A70. The replacements proposed in the 5-year horizon of the current DTE Electric DGP for  
14 system cable, breakers, and URD are just a small fraction of the overall need on the  
15 Company's system. As shown in Table 9, the current investment levels result in an  
16 extremely long replacement rate, ranging from 83 to 189 years. This effectively has  
17 some of this equipment running to failure, vs proactive planned replacement. Further  
18 extending equipment replacements by five years increases the potential risk of  
19 equipment failures, causing the Company to be reactive rather than proactive and the  
20 audit recommendation will only prevent the Company from gaining traction towards  
21 proactive equipment replacements. Major event risk evaluation considers the  
22 likelihood and impact of the complete loss of a substation, which can impact a  
23 significant number of customers (thousands) for an extended duration (a couple of  
24 days). Risk is greatest when there is a combination of at-risk assets and the inability to  
25 transfer load when a failure does occur. Over the last several years, DTE Electric has



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1 experienced an increasing number of major events on the system. In addition to the  
2 outages caused by the initial event, the outages are often extended due to a lack of  
3 system capacity at times in some areas. Replacement of at-risk equipment provides  
4 risk reduction by reducing the probability of failure of key distribution equipment.

5

6 **Q71. What programs are included under System Equipment Replacement?**

7 A71. System Equipment Replacement is divided between substation, overhead,  
8 underground, station upgrades, and the specific programs within each division are  
9 outlined below.

10

11 **A. Substation**

12 **Q72. What programs are included as part of Substation System Equipment**  
13 **Replacement?**

14 A72. There are four programs included as part of Substation System Equipment  
15 Replacement: (1) breaker replacement program; (2) substation regulator replacement  
16 program; (3) disconnect and switcher replacement program; and (4) batteries and  
17 chargers replacement program, all of which are discussed further below.

18

19 **A.1. Breaker Replacement Program**

20 **Q73. What are substation breakers and substation reclosers, and what purpose do they**  
21 **serve?**

22 A73. The path electricity travels across the system can be subjected to interruptions due to a  
23 variety of factors (*e.g.*, a tree falling on an overhead electrical line), which can cause  
24 outages and potentially dangerous situations for customers and employees. Electrical  
25 switches, most commonly breakers or reclosers, are in place at points along the network

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1 to recognize and isolate these interruptions (also known as electrical faults) from the  
2 rest of the distribution system. These switches help to minimize equipment damage  
3 from electrical faults and allow power to continue flowing to as many customers as  
4 possible while restoration is completed for the damaged circuits.

5

6 At the subtransmission and distribution levels, there are large breakers (switches) at  
7 stations and substations that interrupt the current flow when a fault is detected to  
8 minimize equipment damage and to isolate the faulted equipment from the rest of the  
9 system. When a substation breaker fails, it can cause outages to several downstream  
10 circuits, often impacting several hundred customers. These breakers can also fail  
11 catastrophically, with a large flash of energy that is a significant safety risk to substation  
12 employees, and in some cases have resulted in fires and loss of oil to the environment.

13

14 Downstream from the substation breakers, located on distribution circuits, are  
15 substation reclosers. Substation reclosers perform similarly to a breaker. When they  
16 detect faults, they open and isolate the interruption to a smaller area, impacting fewer  
17 customers. Substation reclosers can prevent the substation breaker from opening,  
18 avoiding a larger circuit level outage. Additionally, these reclosers can be used to tie  
19 two circuits together so that, in the event of an outage, one circuit can provide power  
20 to the other if adequate capacity is available. Reclosers have a key role to play in  
21 improving reliability and are the foundation of the automation program, as further  
22 described by witness Rademacher.

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1     **Q74. What is included in the Breaker Replacement program?**

2     A74. The Company has approximately 6,000 breakers on the electrical distribution and  
3         subtransmission systems with approximately 60% of those breakers at an age beyond  
4         their life expectancy. The breakers included in the replacement program have an  
5         obsolete design, typically utilizing insulation oil for fault extinguishing.

6

7         Substation breakers replaced by the Breaker Replacement program are classified into  
8         four categories: (1) distribution breakers, (2) subtransmission breakers, (3) H-breakers,  
9         and (4) substation reclosers. In addition to replacing breakers, the program also  
10        replaces relays and controls to make the equipment Supervisory Control and Data  
11        Acquisition (“SCADA”)-ready. SCADA-ready equipment provides the Electric  
12        System Operations Center (“ESOC”) greater system performance visibility, which will  
13        allow ESOC personnel to remotely reconfigure the grid to restore customers by  
14        isolating faults and/or transferring load to adjacent circuits during both planned and  
15        unplanned outages.

16

17     **Q75. Was the Breaker Replacement program discussed in the prior DTE Electric rate**  
18         **cases?**

19     A75. Yes, the Company’s Breaker Replacement program was included in Case Nos. U-  
20         20162, U-20561, U-20836, U-21297, and U-21534.

21

22     **Q76. What has the Commission previously concluded regarding the Breaker**  
23         **Replacement program investments?**

24     A76. Most recently, the Commission stated in its Order for Case No. U-21534:  
25             The Commission finds DTE Electric’s requested capital  
26             expenditures for its Breaker Replacement program in this case to

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be reasonable and prudent. As stated by the company, “[b]reaker replacement is a prerequisite infrastructure investment . . . that is foundational for the continuity of electric service,” with benefits of the program specifically including “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.”<sup>34</sup>

**Q77. What are the customer benefits from the Breaker Replacement program?**

A77. 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. To maintain and enhance these benefits, the Breaker Replacement program seeks to systematically replace those breakers with known issues or that are otherwise likely to fail in the near future. Recent breaker failures are summarized in Table 10 below.

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<sup>34</sup> Case No. U-21534 Order dated January 23, 2025, p. 113.

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1

**Table 10. Breaker Failures 2020-2024**

| Installation Decade            | 2020       | 2021       | 2022       | 2023       | 2024       | Total      |
|--------------------------------|------------|------------|------------|------------|------------|------------|
| Unknown                        | 1          | -          | -          | -          | -          | 1          |
| 1930s                          | 1          | 3          | 1          | 1          | 1          | 7          |
| 1940s                          | 2          | 2          | 8          | 2          | 4          | 18         |
| 1950s                          | 38         | 35         | 55         | 48         | 40         | 216        |
| 1960s                          | 24         | 7          | 15         | 9          | 17         | 72         |
| 1970s                          | 19         | 16         | 29         | 17         | 22         | 103        |
| 1980s                          | 10         | 7          | 7          | 17         | 9          | 50         |
| 1990s                          | 34         | 22         | 34         | 26         | 18         | 134        |
| 2000s                          | 6          | 6          | 10         | 21         | 12         | 55         |
| 2010s                          | 6          | 32         | 1          | 19         | 20         | 78         |
| 2020s                          | -          | -          | -          | 1          |            | 1          |
| <b>Total Breakers Failures</b> | <b>141</b> | <b>130</b> | <b>160</b> | <b>161</b> | <b>143</b> | <b>735</b> |

2

3 **Q78. How are breakers selected for replacement?**

4 A78. The candidates for breaker replacements are prioritized by the Company's equipment  
 5 engineers based on the following criteria: breakers with known performance issues;  
 6 breakers with no or limited availability of spare parts; breakers with insulation oil for  
 7 fault interrupting medium which is flammable; and breakers that require short  
 8 inspection cycles compared to the rest of the breakers on the Company's system.

9

10 **Q79. Can you provide a specific example of an obsolete breaker type that is prioritized**  
 11 **for replacement by the Breaker Replacement program?**

12 A79. Yes. H-breakers are an obsolete oil breaker design, amongst the oldest in the utility  
 13 industry, dating back to at least the 1920s. H-breakers are no longer manufactured, and  
 14 replacement parts are not available in the market for them.

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1 **Q80. How many Breakers have been replaced through the Breaker Replacement**  
2 **program between 2020 and 2024?**

3 A80. Between 2020 and 2024, the Breaker Replacement program replaced a total of 175  
4 breakers. Included in the replacements were Distribution Breakers, Substation  
5 Breakers, H-Breakers and Substation Reclosers. Please see Table 11 for more details.

6 **Table 11. Breakers Replaced 2020-2024**

| Breaker Type             | 2020      | 2021      | 2022      | 2023      | 2024      |
|--------------------------|-----------|-----------|-----------|-----------|-----------|
| Distribution Breakers    | 20        | 22        | 15        | 16        | 16        |
| Subtransmission Breakers | 7         | 4         | 12        | 6         | 8         |
| H-Breakers               | 6         | 3         | 2         | 3         | 2         |
| Substation Reclosers     | 4         | 10        | 5         | 4         | 10        |
| <b>Total Breakers</b>    | <b>37</b> | <b>39</b> | <b>34</b> | <b>29</b> | <b>36</b> |

7

8 **Q81. Are any Breaker Replacement investments included in the Infrastructure**  
9 **Recovery Mechanism (IRM)?**

10 A81. Yes. The Company's Breaker Replacement investments are partitioned between  
11 recovery through base rates and the Company's authorized IRM mechanism. For the  
12 historical, bridge and test periods in the instant case, Exhibit A-12 Schedule B.5.4.8  
13 shows the partition between the base rates requested in Exhibit A-12 Schedule B5.4  
14 and authorized IRM amounts shown in Exhibit A-33 Schedule X1. Breaker  
15 Replacement investments beyond 2026, as described below, are proposed for inclusion  
16 in the IRM and shown in Exhibit A-33 Schedule X1. Company Witness Willis

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1 discusses the background of the IRM and supports the inclusion of investments in the  
2 IRM.

3 **Q82. What are the Company's expectations for investment in Breaker Replacements**  
4 **beyond the projected test year?**

5 A82. The Company will need to continue investing in Breaker Replacements beyond the test  
6 period covered in this case. The forecast of required investment beyond 2026 is:

- 7 • 2027: \$15 million
- 8 • 2028: \$22 million
- 9 • 2029: \$26 million

10 This reflects the full expected investment for the program from 2027 to 2029 and is  
11 included in this case as the basis for the Company's IRM request supported by  
12 Company Witness Willis.

13

#### 14 **A.2. Substation Regulator Replacement**

15 **Q83. What are Substation Regulators?**

16 A83. Substation regulators are devices that ensure voltages stay within the normal ranges for  
17 which Company and customer equipment is rated to perform. Voltage regulation is  
18 critical to maintaining the health of electric equipment and helps to maintain the service  
19 life of this equipment. Voltage regulation is also critical to maintaining system voltages  
20 within specified ranges, ensuring that customers do not experience the negative effects  
21 of high or low voltage in their homes and businesses.

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1     **Q84. How does replacing Substation Regulators benefit customers?**

2     A84. Voltage regulation is essential to maintain the health and operability of electrical  
3         equipment and prevents the premature damage and failure of this equipment, thus  
4         reducing outages customers experience.

5     **Q85. How many Substation Regulators does the Company plan to replace in this instant**  
6         **case?**

7     A85. In 2024, the Company replaced 2 substation regulators. The Company plans to replace  
8         2 substation regulators in both 2025 and 2026, representing approximately 1.5% of the  
9         total population of substation regulators for both years. The replacement cost is  
10        approximately \$410 thousand per substation regulator. As mentioned in [Preventative  
11        Maintenance Activities – Substation], the population of substation regulators is 249.

12

### 13     **A.3. Disconnect and Switcher Replacement**

14     **Q86. What are Disconnects and Switchers?**

15     A86. Subtransmission disconnect switches (“Disconnects”) are used to sectionalize and  
16         provide isolation points on the electrical system for operational reasons and/or to enable  
17         service and maintenance. Failures of disconnects during operation, when operators  
18         attempt to open or close a disconnect manually, can lead to safety concerns, reduce  
19         system operability, and force additional equipment to be taken out of service to allow  
20         critical work to continue.

21

22         Circuit switchers (“Switchers”) connect the transmission system (120kV) and the  
23         subtransmission system (40kV) to the primary side of a substation power transformer.

24         The purpose of circuit switchers is to protect substation equipment from damage caused



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1 by excess fault current. Circuit switchers are a smaller, less expensive alternative to  
2 circuit breakers. The Company uses circuit switchers primarily for transformer  
3 protection in new construction. Circuit breakers, however, are used instead when  
4 specific requirements, such as the need for reclosing functions or handling high fault  
5 currents, exceed the capacity of the circuit switchers.

6 **Q87. How does the Disconnects and Switchers program benefit customers?**

7 A87. The Company replaces disconnects and switchers that have been identified as at-risk,  
8 and/or have been identified as being undersized compared to the current fault currents,  
9 making them no longer capable of providing proper protection to transformers. These  
10 replacements help to protect the Company's operators while manually operating the  
11 equipment, allow the Company to sectionalize the system (thus reducing the size and  
12 impact of customer outages) when performing work, and to protect the other substation  
13 equipment from damage when excess fault current occurs.

14

15 **Q88. How many disconnects and switchers is the Company planning to replace in this**  
16 **instant case?**

17 A88. In 2024, the Company replaced 19 disconnects and 4 switchers. The Company plans to  
18 replace 16 disconnects and 4 switchers in 2025 and 13 disconnects and 4 switchers in  
19 2026.

20

21 **A.4. Batteries and Chargers Replacement Program**

22 **Q89. What are Batteries and Chargers?**

23 A89. The Company's substations utilize batteries and chargers to provide reliable power  
24 necessary to trip equipment such as breakers during fault conditions. Failures of  
25 batteries and chargers would result in significantly longer duration faults, and therefore

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1 greater damage to system equipment, larger outages, and increased hazards due to the  
2 inability to clear electrical faults.

3

4 **Q90. Why does the Company require proactive battery replacements?**

5 A90. Batteries and chargers have a finite lifespan and eventually require replacement with  
6 new units. The Company identifies batteries and chargers that are at-risk of failure and  
7 at end of useful life and selects them for replacement. These devices ensure that  
8 substation equipment is protected during fault conditions and can continue to operate  
9 properly to maintain reliability.

10

11 **Q91. How many Batteries and Chargers does the Company plan to replace in this**  
12 **instant case?**

13 A91. In 2024, the Company replaced 75 batteries and chargers. The Company plans to  
14 replace 75 batteries and chargers in 2025 and 68 batteries and chargers in 2026

15

16 **B. Overhead Equipment Investments**

17 **Q92. What programs are included as part of Overhead Equipment Investments in**  
18 **System Equipment Replacement?**

19 A92. There are three categories included as part of Overhead Equipment Investments in  
20 System Equipment Replacement: (1) SCADA pole-top device replacement; (2) 40kV:  
21 automatic pole-top switch; and (3) steel pole highway crossings, all of which are  
22 discussed further below.

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1     **B.1. SCADA Pole-Top Device Replacement**

2     **Q93. What are SCADA Pole-Top Devices?**

3     A93. SCADA-enabled pole-top devices, such as overhead three-phase reclosers, are grid  
4         sectionalizing devices that are located at key points on overhead distribution circuits.  
5         These devices act like a circuit breaker, opening under detection of high current due to  
6         a downstream fault, such as a tree branch across two phases. As I explained above,  
7         these devices allow the ESOC to remotely reconfigure the grid to restore customers by  
8         isolating faults and/or transferring load to adjacent circuits with available capacity  
9         during both planned and unplanned outages.

10

11    **Q94. How does replacing SCADA Pole-Top Devices benefit customers?**

12    A94. This program replaces devices that have experienced high rates of failure such as Eaton  
13         Form 3 reclosers and Bridges pole-top switches (“PTS”). Failure of these devices  
14         reduces system operability, thus increasing the amount of extended duration outages  
15         for customers. Replacing these identified devices allows the ESOC to operate the  
16         system more effectively, thereby reducing the number and duration of outages  
17         experienced by customers.

18

19    **Q95. How many SCADA Pole-Top Devices does the Company plan to replace in this**  
20         **instant case?**

21    A95. In 2024, the Company replaced 20 SCADA pole-top devices. The Company plans to  
22         replace 20 SCADA pole-top devices in both 2025 and 2026.

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1     **B.2. 40kV: Automatic Pole-Top Switch**

2     **Q96. What are Automatic Pole-Top Switches (“APTS”)?**

3     A96. The function of the APTS is to sectionalize, isolate, or connect portions of the  
4         subtransmission system. Failure of one of these switches has the potential to interrupt  
5         thousands of customers or result in significant operational constraints. The Company  
6         has identified APTS currently installed in the distribution system that are no longer  
7         working properly or at risk of failure, and where replacement parts are no longer  
8         available due to obsolescence.

9

10    **Q97. How does the 40kV: APTS program benefit customers?**

11    A97. When customer outages occur on the system, if one of these APTS devices is not  
12         working properly, it can cause an extended outage for thousands of customers. This  
13         program increases the reliability of the APTS in the field so that they will operate  
14         properly when necessary, so that these devices can reduce the size and impact of  
15         multiple customer outages and increase reliability for customers.

16

17    **Q98. How many APTS is the Company planning to replace in the instant case?**

18    A98. In 2024, the Company replaced 12 APTS. The Company plans to replace 12 APTS in  
19         2025 and 15 APTS in 2026 of a total population of 144. In recent years, the failure rate  
20         of these switches has been increasing, ranging from 15 to 20 percent. The failure of one  
21         of these switches has the potential to interrupt thousands of customers or result in  
22         significant operational constraints. The 40kV APTS population is considered for  
23         replacement to address high failure rates and unavailable spare parts for early vintages.

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1     **B.3. Steel Pole Highway Crossings Program**

2     **Q99. What is the Steel Pole Highway Crossings program?**

3     A99. The Company has experienced incidents where wood poles have failed, resulting in  
4         wires falling onto highways and causing road closures. In addition to the reliability  
5         impact of a downed wire, the wires that cross highways and fail have the added safety  
6         risk as well as the impact of highway closures. To address these incidents, the Steel  
7         Pole Highway Crossing program identifies current wood pole locations where the  
8         overhead wire crosses a highway and has a high risk of failure and replaces these at-  
9         risk wood poles with steel poles to reduce the likelihood of pole failures that can impact  
10        traffic and public safety and cause customer outages.

11

12    **Q100. How does the Steel Pole Highway Crossings program benefit customers?**

13    A100. While the program was developed to replace high-risk wood poles with steel poles to  
14        reduce the risk of overhead equipment falling and disrupting the highway system, it  
15        provides an ancillary reliability benefit as failed poles can result in customer outages.

16

17    **Q101. How many Steel Pole Highway Crossings does the Company plan to complete in**  
18       **this instant case?**

19    A101. In 2024, the Company installed 6 Steel Pole Highway Crossings and plans to complete  
20        1 crossing in 2025 and 6 in 2026.

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1     **C. Underground System Investments**

2     **Q102. What programs are included as part of Underground (“UG”) System Investments**  
3         **in System Equipment Replacement?**

4     A102. There are two programs included as part of Underground System Investment in System  
5         Equipment Replacement: (1) the cable replacement program and (2) the underground  
6         residential distribution (URD) program, both of which are discussed further below.

7  
8     **C.1. System Cable Replacement Program**

9     **Q103. What is System Cable, and how is it different from URD Cable?**

10    A103. System cable is a specific type of cable designed and used for underground distribution  
11        and subtransmission on the Company’s primary electric system. System cable consists  
12        of large diameter cable surrounded by various types of insulation, and it is installed  
13        underground in vaults and ducts that runs between manholes.

14  
15        System cable is used for a different purpose than URD cable. System cable is used to  
16        transmit higher voltage electricity from substation to substation and to feed primary  
17        circuits, while URD cable is designed to provide lower voltage electricity directly to  
18        and within residential neighborhoods. URD is discussed in more detail later in my  
19        direct testimony.

20  
21    **Q104. What are the key drivers of the Company’s System Cable Replacement program?**

22    A104. System cable is a critical component of the distribution and subtransmission systems.  
23        While system cable provides high resiliency to storms, system cable failures do happen  
24        and can interrupt a large number of customers for an extended period of time due to the  
25        longer amount of time it typically takes to locate and replace a failed cable. System

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1 cable is also installed in an underground system of manholes and conduits, often in or  
2 adjacent to roads, making access more challenging. In addition to road traffic to  
3 manage, the manholes can experience structural failures and flooding, and the conduits  
4 also experience structural challenges that can prevent access and removal. System cable  
5 replacement is an industry standard program to reduce system risk and support  
6 reliability.

7

8 When a system cable fails, the customers fed from that circuit are typically switched to  
9 a redundant, or back-up cable, to restore power, and remain on the alternate circuit until  
10 the original cable is replaced and back in service. The process to replace the cable  
11 includes locating the fault, de-energizing the circuit, cutting the failed section(s),  
12 pulling the failed cable out of the conduit, installing new cable, reconnecting (splicing)  
13 the new cable to the existing circuit, and re-energizing the circuit. During the time it  
14 takes to find and repair the cable, the system has lost redundancy and has increased risk  
15 for longer duration outages (if a failure occurs on the redundant circuit). Some  
16 customers, such as hospitals, have policies of limiting services during events where  
17 backup power is not available. System cable failures can also cause failures in other  
18 equipment, including adjacent cables and switchgear, which can then impact an even  
19 larger number of customers for a longer period of time. The Company has had an  
20 average of 222 system cable failures per year over the last five years (Table 12).

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**Table 12. System Cable Failures by Cable Type and Year**

| Failures by Cable Type      | 2020<br>Actual | 2021<br>Actual | 2022<br>Actual | 2023<br>Actual | 2024<br>Actuals |
|-----------------------------|----------------|----------------|----------------|----------------|-----------------|
| PILC                        | 161            | 180            | 202            | 171            | 144             |
| EPR                         | 24             | 17             | 24             | 37             | 28              |
| VCL                         | 6              | 5              | 8              | 16             | 13              |
| Gas                         | 5              | 3              | 3              | 12             | 3               |
| XLPE Post-1990              | -              | -              | -              | -              | -               |
| XLPE Pre-1990               | 7              | 5              | 1              | 16             | 9               |
| Butyl Rubber                | -              | 3              | 2              | 3              | 1               |
| <b>Total Cable Failures</b> | <b>203</b>     | <b>213</b>     | <b>240</b>     | <b>255</b>     | <b>198</b>      |

**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**XLPE:** system cable that is insulated with cross-linked polyethylene**Butyl Rubber:** system cable that is insulated with butyl rubber

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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 9). 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 and logistical concerns include the need to pump water out of the manholes



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1 (Figure 10) before work can begin and environmental management of the wastewater,  
2 the need to follow safety protocols including ensuring the air quality is safe for entry  
3 in what is designed as a confined space and often including remediation of  
4 contaminants such as lead and asbestos. Once the manholes can be entered safely, the  
5 work includes inspecting and testing long stretches of cable to find the fault, and  
6 identification of adjacent hazards. Finally, the crews typically pull and splice the cable  
7 as described above, which can be difficult during an emergent failure and restoration  
8 situation.

9 **Figure 9. System Cable – UG Collapsed Duct**



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**Figure 10. System Cable – Cable Inside Manhole**



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In addition to general concerns that are related to age, some 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”), a condition that has contributed to switchgear failures. As another example, gas cable, 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 Chiu), 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

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factor used by engineers to determine a need for replacement, in the Company's experience, failure rates increase with age as older cable has typically been exposed to more fault currents over time and has longer water exposure.

Table 13 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 the engineering asset health assessment for system cable, the Company has determined that approximately 28% of its system cable is considered 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.

**Table 13. System Cable Types - Average Age and Life Expectancy**

| Cable Type                | PILC  | EPR   | VCL  | Gas  | XLPE<br>Pre-<br>1990 | XLPE<br>Post-<br>1990 | Butyl |
|---------------------------|-------|-------|------|------|----------------------|-----------------------|-------|
| Miles                     | 2,069 | 748   | 95   | 47   | 58                   | 48                    | 31    |
| % of Total<br>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<br>Expectancy | 40    | 35    | 40   | 40   | 25                   | 40                    | 25    |

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1 Planned replacement of UG system cable allows the Company to proactively target  
2 cable at high risk of failure. This allows for a more strategic, and more efficient process  
3 to replace large portions of cable in order to reduce the risk of failures and increase  
4 redundancies in a given area.

5

6 **Q105. What is the scope of the System Cable Replacement program?**

7 A105. The System Cable Replacement program identifies and replaces at-risk system cable.  
8 System cable replacement prioritization is based on multiple factors including  
9 insulation type, failure history, system impacts, and cable loading. These cables are  
10 installed in conduit and spliced together in manholes. When replacing system cable,  
11 the Company will also replace failed/collapsed conduit, ducts, and manholes, upgrade  
12 substation cable positions, and rebuild cable poles, as necessary.

13 As part of the System Cable Replacement program, the Company also implements the  
14 System Cable Testing program. A comprehensive System Cable Testing program is  
15 essential to maintain and improve the reliability and safety of the electrical  
16 infrastructure. Regular testing helps identify potential issues before they lead to failures  
17 and reduces the risk of unexpected outages. This proactive approach ultimately leads  
18 to a reduction in reactive cost and improved reliability for customers.

19

20 The Company developed the testing program with a structured approach to ensure a  
21 gradual increase in the number of circuits tested, while also emphasizing efficiency and  
22 cost management. Specifically, the program aims to start with 40 circuits tested in Year  
23 1 (2026), increasing the circuits tested each year until the Company reaches 500 circuits  
24 by Year 4 (2029). The cost per circuit generally ranges from \$25,000 to \$50,000, which

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1 includes fully loaded labor costs for planning, pre-and post-switching of load, and  
2 actual testing of the circuit. Utilizing this structured approach, the Company's  
3 forecasted budget and number of circuits tested each year are as follows:

- 4 • Year 1 (2026): Budget: \$2,000,000; Circuits: 40-80;
- 5 • Year 2 (2027): Budget: \$3,000,000; Circuits: 60-120;
- 6 • Year 3 (2028): Budget: \$4,000,000; Circuits: 80-160; and
- 7 • Year 4 (2029): Budget: \$5,000,000; Circuits: 200.

8 The costs associated with the System Cable Testing program, for Year 1 (2026), are  
9 O&M expenses that appear in Exhibit A-13 Schedule C5.6 p.1.

10

11 **Q106. What did the Commission state with respect to the System Cable Replacement**  
12 **program in Case No. U-21534?**

13 A106. Yes. The Commission stated in its Order in Case No. U-21534:

14 The Commission finds DTE Electric's requested capital  
15 expenditures for its System Cable Replacement and URD  
16 Replacement programs to be reasonable and prudent. As stated by  
17 the company, system cable and URD cable replacement efforts  
18 benefit customers by prioritizing and proactively replacing cables  
19 and transformers to reduce the risk of failures and prolonged  
20 outages, thereby supporting continued reliability.<sup>35</sup>

21

22 **Q107. Did the Audit Report include a conclusion and recommendation related to System**  
23 **Cable?**

24 A107. Yes, the Audit Report concluded "DTE's subtransmission cable failure rate has been  
25 too high."<sup>36</sup> Additionally, the Audit Report recommended the Company "[p]lan for  
26 replacement of poor-performing subtransmission cable types over the long term."<sup>37</sup>

27

<sup>35</sup> Case No. U-21534 Order dated January 23, 2025, pp. 111-112.

<sup>36</sup> Case No. U-21305, [068cs00000AyaNpAAJ](#), Audit Report, Part Two, Chapter 1, p. 42

<sup>37</sup> Case No. U-21305, [068cs00000AyaNpAAJ](#), Audit Report, Part Two, Chapter 1, p. 44

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1     **Q108. How does the Audit Report recommendation impact the Company's existing plan**  
2           **for completion of subtransmission cable?**

3     A108. The Company agrees with the replacement of poor-performing subtransmission cable,  
4           which is a subset of system cable, but disagrees with extending the program over the  
5           longer term. Subtransmission cables play a vital role in delivering electricity to  
6           customers and can cause extended prolonged outages when they fail due to the  
7           complexity of reactive replacement under emergency situations, therefore, the  
8           Company believes this program should continue to move forward in the time frame  
9           recommended by the Company.

10    **Q109. What are the potential risks and consequences of replacement of poor-performing**  
11          **subtransmission cable types over a longer term?**

12    A109. Over the last several years, the Company has experienced an increasing number of  
13          major events on the system. Delaying the replacement of subtransmission cables  
14          increases risk by increasing the probability of failure of these critical assets. Sixty-four  
15          percent of system cable, or approximately 1,980 miles, is at or near the end of useful  
16          life, and 28% is a candidate for replacement based on the findings in the asset health  
17          assessment. The Company's current annual cable replacement program is a small  
18          fraction of the identified miles for replacement and is therefore already operating on a  
19          longer than preferred cadence. The Company replaced approximately 10 miles in 2024  
20          and plans to replace 11 miles in 2025. Assuming an average of 10.5 miles per year, the  
21          1,980 miles of at-risk system cable will be replaced in 189 years. The Company is  
22          increasingly concerned about the level of failure-risk posed by the age and condition  
23          of system cable because of the impact a system cable failure has on the overall system.

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1 When system cable fails, it reduces the level of redundancy of the grid and increases  
2 the risk of long duration customer outages.

3

4 **Q110. What sections of cable are replaced by the System Cable Replacement program?**

5 A110. The System Cable Replacement program prioritizes and replaces sections of cable that  
6 are deemed at-risk based on their engineering asset health assessment as discussed  
7 above. If there are sections of cable on a circuit that are not deemed to be at-risk, they  
8 are not replaced by the program.

9

10 **Q111. How much system cable was replaced in 2024 and prior years?**

11 A111. The Company replaced approximately 12 miles of system cable in 2024 and has  
12 replaced approximately 38 miles of system cable over the last five years (Table 14).

13

14 **Table 14. System Cable Program 2020-2025**

|                                  | 2020<br>Actual | 2021<br>Actual | 2022<br>Actual | 2023<br>Actual | 2024<br>Actual |
|----------------------------------|----------------|----------------|----------------|----------------|----------------|
| Cable Miles Replaced             | 6              | 7              | 5              | 8              | 12             |
| Capital Investment (\$ millions) | \$12.1         | \$15.0         | \$27.7         | \$22.5         | \$25.6         |

15

16 **Q112. How much system cable replacement is planned for 2025-2026?**

17 A112. The Company plans to replace approximately 6 miles in 2025 and 13 miles in 2026.

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1     **Q113. How does the System Cable Replacement program benefit customers?**

2     A113. Replacing at-risk system cable supports continued reliability for customers. The  
3         underground cable system is designed with multiple redundancies to maintain customer  
4         reliability. While single cable failures do not normally result in customer outages, if  
5         the primary and redundant cables fail at the same time, it results in prolonged outages  
6         for customers. Some types of industrial class customers, such as hospitals, are not able  
7         to tolerate the risk of running with a single cable and therefore reduce or shut down  
8         some functions when this happens. This program reduces overall risk to customers and  
9         the grid by proactively replacing cables before they fail, in order to maintain necessary  
10        redundancies for this critical part of the system as designed. The program also reduces  
11        safety risk, as I noted earlier in my testimony.

12

13    **Q114. What are the Company's expectations for investment in System Cable beyond the**  
14    **projected test year?**

15    A114. The Company will continue to need to invest in System Cable beyond the test period  
16    covered in this case. The forecast of required investment beyond 2026 is:

- 17           • 2027:         \$25 million  
18           • 2028:         \$30 million  
19           • 2029:         \$34 million

20    This reflects the full expected investment for the program from 2027 to 2029 and is  
21    included in this case as the basis for the Company's IRM request supported by  
22    Company Witness Willis.



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1     **C.2. Underground Residential Distribution (“URD”) Replacement program**

2     **Q115. What is URD cable, and why does the Company replace it?**

3     A115. URD is a specific type of cable designed for underground residential use on the  
4         Company’s secondary electric system, as an alternative to overhead construction. URD  
5         consists of small diameter cable surrounded by polyethylene insulation and is either  
6         directly buried into the ground or less frequently is installed inside conduit (Figure 11).  
7         URD design also includes ground level pad mounted transformers. Because  
8         underground repairs can take significant amounts of time to locate and repair when  
9         compared to overhead infrastructure, URD systems are typically looped so that there  
10        are two paths to feed customers in case one URD cable fails.

11

12

**Figure 11. URD Cable – Example**



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1 As mandated by Michigan Administrative Code R. 460,512, all residential subdivisions  
 2 in the Company's service territory built since January 1, 1971, are served with URD  
 3 cable. There are two primary types of URD cable, differentiated by manufacture date.  
 4 Pre-1985 URD cable has XLPE (non-tree retardant) insulation, while post-1985 the  
 5 insulation has TR-XLPE (tree-retardant) insulation. In cable insulation, "treeing" refers  
 6 to the tree-like pattern of insulation breakdown. The breakdown typically originates at  
 7 an impurity or defect in the solid insulation and grows gradually over time to resemble  
 8 the branches of a tree, leading to a cable failure. There are approximately 11,000 total  
 9 miles of URD cable on the system, with approximately 2,686 miles (24%) being pre-  
 10 1985 non-tree retardant vintage (Table 15).

11

12 **Table 15. URD Cable Types - Average Age and Life Expectancy**

| URD Type                | Pre-1985 | 1985+ |
|-------------------------|----------|-------|
| URD Cable Miles         | 2,686    | 8,742 |
| % of Total Population   | 24%      | 76%   |
| Average Age (Years)     | 46       | 25    |
| Life Expectancy (Years) | 40       | 40    |

13

14 In addition to failures caused by treeing described above, the rate of URD cable failures  
 15 typically increases with the age of the cable, and the rate further increases once a cable  
 16 experiences its first failure. Manufacturer expected useful life for URD cable is  
 17 approximately 40 years. Useful life is a standard industry term that does not represent  
 18 the actual life of an asset, but rather the age at which an installed asset is expected to

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1 experience increasing failure rates and reduced performance such that it is often more  
2 prudent to replace than to continue to repair and maintain. For the five-year period from  
3 2020 through 2024, there were on average approximately 995 URD cable failures per  
4 year as seen in Table 16.

5

6

**Table 16. URD Cable Failures**

|                    | 2020  | 2021 | 2022 | 2023 | 2024  | Avg |
|--------------------|-------|------|------|------|-------|-----|
| URD Cable Failures | 1,036 | 986  | 900  | 864  | 1,191 | 995 |

7

8 **Q116. What is the scope of the URD Replacement program?**

9 A116. There are two primary types of work performed by the URD Replacement program:

10 (1) prioritizing and replacing existing URD cable and (2) replacing live-front UG  
11 transformers with dead-front UG transformers.

12

13 The program prioritizes and replaces URD cable based on multiple factors including  
14 number of failures on the circuit, and number of customers affected by those failures,  
15 and URD cable type. The program also includes the replacement of live-front  
16 transformers with dead-front transformers. Some URD cable is fed from live-front  
17 transformers, which is an obsolete design that does not include protective coverings  
18 over energized equipment and therefore poses a potential safety risk to crews in the  
19 field while performing operating work once the external transformer covering is  
20 removed.

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1 Single URD cable faults (outages) are typically restored quickly after an UG splicing  
2 crew arrives and bypasses the URD failure by back feeding the customers from another  
3 source on the URD loop. However, once the customers are restored, there is follow-up  
4 work required to locate and repair the URD fault that caused the original outage, and  
5 to restore the system to normal operating conditions. This follow-up work is called an  
6 open loop. These open loops leave the system without redundancy, such that if a second  
7 URD failure occurs on the same URD loop, a new long-duration outage (4+ hours) will  
8 result for the customers as there is no redundancy to back feed the customers as  
9 described above, while replacing the failed URD cable. Second URD failures within  
10 six months of the original failure have occurred on average 75 times annually over the  
11 last five years (Table 17).

12

13 **Table 17. URD Double Cable Failures Within 6 months**

|                           | 2020 | 2021 | 2022 | 2023 | 2024 | Avg       |
|---------------------------|------|------|------|------|------|-----------|
| URD Double Cable Failures | 37   | 59   | 32   | 115  | 125  | <b>74</b> |

14

15 In addition, planned replacements are more cost effective than repairing failures, as the  
16 Company can strategically plan to replace entire circuits of URD and live-front  
17 transformers, rather than reactively fixing smaller sections of the circuit following a  
18 failure.

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**Table 18. URD Double Cable Failure Outage Data**

| URD Double Failures w/in 6 months | 2020      | 2021      | 2022      | 2023      | 2024      |
|-----------------------------------|-----------|-----------|-----------|-----------|-----------|
| Customers Impacted                | 1,923     | 2,542     | 1,749     | 5,415     | 4,559     |
| Outage Duration                   | 182 hours | 370 hours | 187 hours | 791 hours | 577 hours |
| Average Outage Duration           | 4.9 hours | 6.3 hours | 5.9 hours | 6.9 hours | 5.8 hours |
| Total Customer Outage Minutes     | 484,347   | 837,078   | 683,363   | 2,574,899 | 1,410,736 |

2

3

4

5

6

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 12).

7

**Figure 12. (A) Live-front and (B) Dead-front UG Transformer**



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1 **Q117. How does the URD Cable Replacement program benefit customers?**

2 A117. The program will improve reliability by reducing the number of residential customer  
3 interruptions experienced by URD cable failures in the areas in which this program has  
4 completed work. This will also benefit customers by reducing the risk of multiple  
5 failures and long duration outages due to pre-existing open loops as described above.

6

7 **Q118. Were URD Replacement program investments addressed in prior rate cases?**

8 A118. Yes. The URD Replacement program was included in Case Nos. U-20162, U-20561,  
9 U-20836, U-21297, and U-21534. Most recently, in the Commission's Order in Case  
10 No. U-21534, the Commission found the requested capital expenditures for the URD  
11 Replacement program to be reasonable and prudent, as stated above with System Cable  
12 Replacements.<sup>38</sup>

13 **Q119. How much URD cable was replaced in 2024?**

14 A119. The URD Replacement program replaced 71.3 miles of URD cable in 2024 and has  
15 replaced approximately 219 miles of URD cable from 2020-2024 (Table 19).

16

17 **Table 19. URD Cable Miles and Transformers Replaced 2020-2024**

|                                     | 2020<br>Actual | 2021<br>Actual | 2022<br>Actual | 2023<br>Actual | 2024<br>Actual |
|-------------------------------------|----------------|----------------|----------------|----------------|----------------|
| URD Miles Replaced                  | 3.6            | 24.5           | 44.7           | 75.3           | 71.3           |
| Live-front Transformers<br>Replaced | 1              | 63             | 110            | 111            | 211            |

<sup>38</sup> Case No. U-21534 Order dated January 23, 2025, p. 112

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**Q120. Are any URD Replacement investments included in the Infrastructure Recovery Mechanism (IRM)?**

A120. Yes. The Company's URD Replacement investments are partitioned between recovery through base rates and the Company's authorized IRM mechanism. For the historical, bridge and test periods in the instant case, Exhibit A-12 Schedule B.5.4.8 shows the partition between the base rates requested in Exhibit A-12 Schedule B5.4 and authorized IRM amounts shown in Exhibit A-33 Schedule X1. URD Replacement investments beyond 2026, as described below, are proposed for inclusion in the IRM and shown in Exhibit A-33 Schedule X1. Company Witness Willis discusses the background of the IRM and supports the inclusion of investments in the IRM.

**Q121. What are the Company's expectations for investment in URD Replacement beyond the projected test year?**

A121. The Company will continue to need to invest in these programs beyond the period covered in this case. The forecast of required investment beyond 2026 is

- 2027: \$15 million
- 2028: \$20 million
- 2029: \$26 million

This reflects the full expected investment for the URD Replacement program from 2027 to 2029 and is included in this case as the basis for the Company's IRM request supported by Company Witness Willis.

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1     **D. Station Upgrade Projects**

2     **Q122. What are Station Upgrade projects?**

3     A122. Station Upgrade Projects are designed to enhance the safety and reliability of the  
4         electric subtransmission and distribution system by upgrading key infrastructure at  
5         DTE Electric stations and improving relay systems at points of interconnection with  
6         the International Transmission Company (ITC). The projects also focus on reducing  
7         reactive costs and ensuring a more reliable and resilient electric grid.

8

9     **Q123. What Station Upgrade projects are part of this proceeding?**

10    A123. There are three station risk upgrade projects that are part of the current proceeding. The  
11       projects include: (1) Lincoln station project; (2) Navarre station project; (3) 120kV  
12       Relay Upgrades in coordination with ITC Projects. These projects are scheduled to be  
13       completed between 2025 and 2027 and will involve upgrades to replace breakers and  
14       the associated relay panels and enable advanced SCADA capabilities such as fault  
15       detection and remote monitoring.

16    **Q124. Why was the Station Upgrade: Lincoln Station project created?**

17    A124. Lincoln Station requires a comprehensive station upgrade due to 24 kV relay panels  
18       that are outdated (60+ years old) and cannot be maintained or modified as well as at  
19       risk-breakers and disconnects. Further, space constraints prevent the installation of new  
20       panels, necessitating a new configuration.

21

22    **Q125. What is the scope of the Station Upgrade: Lincoln Station project?**

23    A125. The scope of the Station Upgrade: Lincoln project is to replace 14 24kV oil circuit  
24       breakers with gas circuit breakers, replace existing relay panels with 20 new



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1 microprocessor-based relay panels, and remove oil circuit breakers and associated relay  
2 panels. The new relay panels will include three bus panels and one under-frequency  
3 panel.

4

5 **Q126. What are the customer benefits of the Station Upgrade: Lincoln Station project?**

6 A126. The station upgrades at Lincoln Station will include removing at-risk relays, which will  
7 result in improved fault detection and response to overloads. The station upgrades also  
8 allow for remote modification of relay settings, which means fewer field visits and  
9 reduction in reactive costs during non-storm and storm events.

10

11 **Q127. Why was the Station Upgrade: Navarre Station project created?**

12 A127. Much like the Lincoln Station, the Navarre Station requires a comprehensive station  
13 upgrade due to 24 kV relay panels that are outdated (60+ years old) and cannot be  
14 maintained or modified as well as at risk-breakers and disconnects. Further, space  
15 constraints prevent the installation of new panels, necessitating a new configuration.

16

17 **Q128. What is the scope of the Station Upgrade: Navarre Station project?**

18 A128. The scope of the Station Upgrade: Navarre project is to replace 20 24kV oil circuit  
19 breakers with gas circuit breakers, replace existing relay panels with 35 new  
20 microprocessor-based relay panels, and remove oil circuit breakers and associated relay  
21 panels. The new relay panels will include three bus panels and one under-frequency  
22 panel.

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1 **Q129. What are the customer benefits of the Station Upgrade: Navarre Station project?**

2 A129. The benefits of the Navarre Station project are the same as the benefits I discussed in  
3 relation to the Lincoln Station project.

4  
5 **Q130. Why was the Station Upgrade: 120kV Relay Upgrades for ITC Projects created?**

6 A130. The ITC initiates work to upgrade the 120kV relaying at points of interconnection with  
7 DTE Electric. The Company supports the ITC projects by upgrading obsolete DTE  
8 Electric relays at a lower cost than reactive work or planned capital work. This  
9 approach helps avoid unfavorable shutdowns due to the system being out of normal  
10 configuration and/or system peak loads.

11

12 **Q131. What is the scope of the Station Upgrade: 120kV Relay Upgrades for ITC**  
13 **Projects?**

14 A131. The Company will perform the 120 kV relay upgrades as shown in Table 20.

15

16 **Table 20. Station Upgrades: 120kv Relay Upgrades by Year**

| Year | Station    | Number of Upgrades |
|------|------------|--------------------|
| 2025 | Hager      | 2                  |
| 2025 | Sloan      | 1                  |
| 2025 | Lee        | 1                  |
| 2025 | Bloomfield | 1                  |
| 2026 | Dorset     | 1                  |
| 2026 | Duval      | 2                  |
| 2026 | Erin       | 1                  |
| 2026 | Levan      | 2                  |
| 2026 | Mack       | 1                  |

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1     **Q132. What are the customer benefits of the Station Upgrade: 120kV Relay Upgrades**  
2             **for ITC Projects?**

3     A132. The projects offer several benefits to customers. First, the work will be planned,  
4             designed, and executed during off-peak loads in cooperation with ITC, and it will not  
5             impact the timelines of ongoing projects. Thus, replacing relay panels during a  
6             shutdown for an ITC-driven project will avoid a separate future shutdown. Second, the  
7             smart microprocessor relays generate alarms, Light Emitting Diodes (LEDs) and time-  
8             stamped event reports for troubleshooting and maintenance targets, thereby avoiding  
9             outages or reducing outage durations. Third, additional design in selected protective  
10            relays provides enhanced remote control. Relay failure alarms provide advanced notice  
11            to replace the failed relay before an actual event without a shutdown due to redundancy  
12            in the protective scheme. These relaying upgrades will contribute to strengthening the  
13            electric grid.

14

15     **VIII. Major Event Risk**

16     **Q133. What are Major Event Risk Projects?**

17     A133. Major Event Risk Projects are projects designed to remediate failures that have already  
18             occurred or to prevent catastrophic failures in the future. The Company's Major Event  
19             Risk Projects are divided between substation risk, the mobile fleet program, and  
20             portable generators. Substation risk projects are further divided between flood-related  
21             substation risk projects and failed equipment-related substation risk projects.

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1     **A. Substation Risk Projects**

2     **Q134. What are Substation Risk projects?**

3     A134. Projects in this category are designed to remediate failures of substations that have  
4         already occurred, or to prevent catastrophic substation failures in the future. Substation  
5         risk events typically are caused by equipment failure (*e.g.*, transformer or switchgear),  
6         fires, or flooding. Because a substation typically supports several circuits, substation  
7         risk events often impact many customers. In addition to affecting a large number of  
8         customers, they can result in lengthy outages to repair or replace large equipment. An  
9         entire substation is difficult to restore, with methods often limited to Mobile Fleet  
10        program assets such as diesel generators and portable substations to provide temporary  
11        support, or switching load to adjacent substations if there is available jumpering  
12        capacity. The amount of adjacent substation jumpering that can be achieved, and how  
13        quickly it can be implemented, is dependent on several factors such as whether the  
14        substation is the same circuit voltage class, there is adequate existing capacity and  
15        cable/conductor size, and whether sufficient operating devices are already installed in  
16        field. Substation Risk projects, as a result, target replacing at-risk switchgear, which  
17        includes the enclosure with breakers, relays, and wiring, within the substations to  
18        reduce the risk of major outages.

19

20        These Substation Risk projects are prioritized utilizing the Global Prioritization Model  
21        ("GPM") as discussed in more detail in Company Witness Kryscynski's testimony, at  
22        substations where deployment of Mobile Fleet program assets cannot restore the entire  
23        substation load; in other words, customers will be out for more than 24 hours in the  
24        event of a failure. Details of the projects included in this instant case can be found  
25        below and in Exhibit A-23, Schedule M5.

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1     **Q135. What Substation Risk projects are part of this proceeding?**

2     A135. There are thirteen substation risk programs and/or projects that are part of the current  
3         proceeding—two that are flood-related substation risk projects and 11 that are failed  
4         equipment-related substation risk projects. The two flood-related substation risk  
5         projects include: (1) McGraw project and (2) Flood Defense program. The 11 failed  
6         equipment-related substation risk projects include: (3) Apache project; (4) Belleville  
7         project; (5) Chestnut project; (6) Drexel project; (7) Hood project; (8) Port Huron  
8         project; (9) Savage project; (10) Savage Switchgear Replacement project; (11) Seville  
9         project; (12) Voyager project; (13) Waterman project; The McGraw project and Flood  
10        Defense program are continuations of the same projects and/or programs for which the  
11        Commission allowed cost recovery in Case No. U-21534.

12    **A.1. Flood-related Substation Risk Projects**

13    **Q136. Can you describe the drivers of the Substation Risk: McGraw project?**

14    A136. Record heavy rains in June 2021 led to significant catastrophic flooding in the McGraw  
15        substation. The sub-grade part of the substation, which houses the station's busses and  
16        breakers, was engulfed in storm water. The result was a failure of position breakers,  
17        busses, transfer busses, and house service panels, with the substation experiencing a  
18        total loss of load carrying ability. That failure, in turn, caused 6,000 customer outages,  
19        lasting between 16 hours to 5 days based on the ability to restore power.

20

21        Figure 13 below depicts the stairway into the sub-grade part of the McGraw Substation  
22        following the June 2021 flooding event. This area is where all the cables come into  
23        and out of the substation. As shown, the water covered the stairway and, as a result,  
24        also covered the cables.

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1

**Figure 13. McGraw Substation Flooding – Stairway to Sub-Grade Portion of Station**



2

3

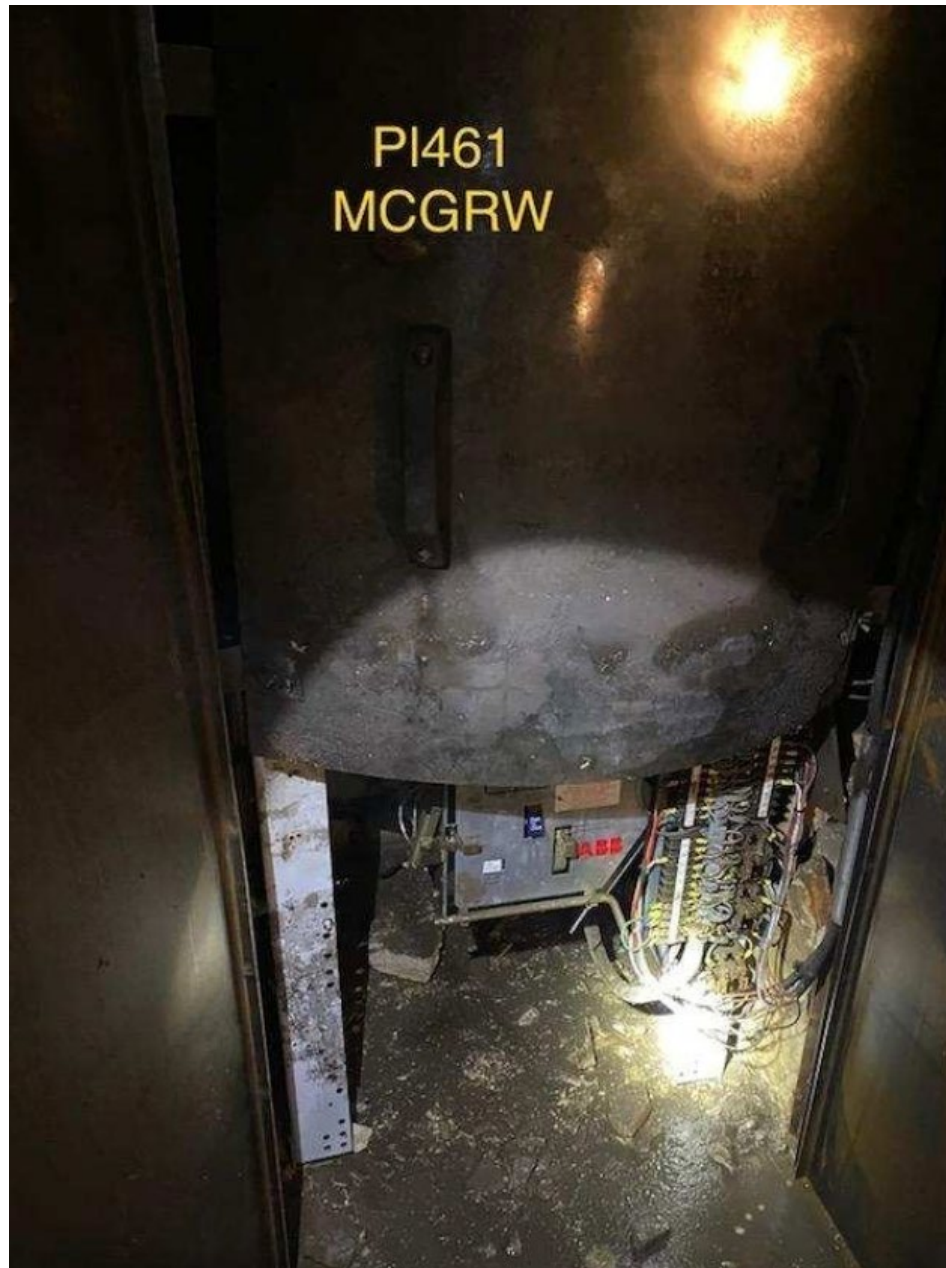
Figure 14 below was taken shortly after the water receded from the substation and

4

shows the remaining sludge covering the equipment.

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1      **Figure 14. McGraw Substation Flooding –Remaining Sludge After Water Receded**



2

3      The Company's initial emergency response included a mix of jumpering load away  
4      from McGraw Substation to adjacent substations, and use of the Mobile Fleet Program  
5      portable generation equipment. All customers were placed back on utility power within

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1 two weeks after the flooding event by means of station jumpering and breaker  
2 replacement.

3

4 The substation, however, continued using some Mobile Fleet program equipment and  
5 a temporary overhead circuit constructed on city of Detroit and MDOT property (*i.e.*,  
6 the pole farm as depicted in Figure 15 below) to bypass damaged and inoperable  
7 substation equipment, until a permanent solution is constructed on DTE Electric  
8 property. Customers have expressed concerns about the continued presence of the large  
9 temporary mobile equipment located in residential neighborhoods. While the current  
10 temporary configuration supports load day-to-day, it is higher risk than standard utility  
11 construction, and there have been subsequent outage impacts for these customers. For  
12 example, the portable substation in the field was struck by a vehicle and taken out of  
13 service, which caused additional outages to customers until a replacement could be  
14 installed. The temporary configuration also lacks automatic ground detection alarms  
15 to indicate a downed 4.8kV wire. Substation field personnel visit the substation daily  
16 to manually check for grounds at McGraw Substation until the permanent facilities can  
17 be built.



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1

**Figure 15. McGraw Substation – Temporary Pole Farm**



2

3 **Q137. What actions did the Company take to prevent similar flooding events at other,**  
4 **similar substations?**

5 A137. After the initial emergency response, the Company's engineers and field personnel  
6 assessed the substation's condition, as well as the long-term plans for the McGraw  
7 Substation and surrounding circuits. The Substation Risk: McGraw project was created  
8 after these assessments, with the goals of preventing future failures due to flooding and  
9 returning customers to normal utility service.

10

11 Additionally, because of the flooding at McGraw Substation, as well as the increase in  
12 frequent and severe weather events causing flooding, the Company hired a third-party  
13 contractor to survey its other substations with sub-grade equipment to evaluate the risk

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1 of potential catastrophic flooding at those locations. The result of the third-party  
2 assessment was the Substation Risk: Flood Defense program that is discussed later in  
3 my testimony.

4

5 **Q138. What is the scope of the Substation Risk: McGraw project?**

6 A138. The scope of the Substation Risk: McGraw project is to:

- 7 i) Install new substation equipment on the second level of McGraw Substation,  
8 including a new circuit feeder and Automatic Throwover (ATO) breakers, as well  
9 as new relays and voltage control panels. As part of this installation,  
10 network/SCADA capabilities are being installed to increase reliability.  
11 Additionally, while all critical equipment has been moved out of the sub-grade level  
12 of the station, sump pumps and a manual diversion valve have been installed to  
13 improve response to any potential flooding in the basement.
- 14 ii) Provide for exterior expansion of the substation. After considerable effort, and in  
15 light of limited options, in 2024, the Company acquired land parcels and vacated  
16 right-of-way from the City of Detroit and MDOT to allow exterior expansion for  
17 equipment that will be removed from the basement.
- 18 iii) Construct exterior expansion of substation equipment including two 24-4.8kV  
19 10/12 MVA transformers with circuit switcher protection and a nine-position power  
20 delivery center (PDC) and network/SCADA capabilities installed to increase  
21 reliability with an anticipated completion in 2025.
- 22 iv) Decommissioning and removal of failed substation equipment. The Company  
23 anticipates completing decommissioning and removal of failed substation  
24 equipment in 2026. Additionally, the 2026 scope will include follow-up work for

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1 the expansion including manhole repair, fencing, finish oil containment, and storm  
2 drainage work.

3 More details of this project can be found in Exhibit A-23, Schedule M5.  
4

5 **Q139. What are the customer benefits of the Substation Risk: McGraw project?**

6 A139. Completion of the McGraw project will return customers fed from the McGraw  
7 Substation to normal utility service, removing the necessity for the continued use of the  
8 mobile generation equipment and the temporary pole farm, thus improving the  
9 reliability of service for all affected customers. Once completed, this Project will also  
10 greatly reduce or eliminate future flooding risk to the substation since all equipment  
11 necessary to serve customers will be located on the second floor of the substation or  
12 outside of the building (rather than the basement). The project is anticipated to be  
13 completed in 2026. The project extension into 2025 was due to the complex sequence  
14 for property acquisition took longer than originally anticipated, delaying the start of the  
15 exterior work by several months. Additionally, the permanent utility infrastructure will  
16 allow for the removal of the large temporary equipment that has been a customer  
17 concern.  
18

19 **Q140. What should the Commission conclude regarding the continued investment in the**  
20 **Substation Risk: McGraw project you describe above in this instant case?**

21 A140. The Commission should approve the McGraw project investment in this proceeding  
22 because it is reasonable, prudent, and necessary. This project is necessary to serve the  
23 customers fed by the McGraw substation in a safe, reliable, and permanent manner,  
24 and because the project has been designed and will be constructed to minimize the  
25 likelihood of future flooding impacts and inconvenience for these customers. This

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project will return McGraw back to full operability, remove all mobile generation equipment, eliminate the need for the temporary pole yard, build switching and redundancy for these circuits, and restore service to customers with better, permanent, long-term utility equipment rather than the current temporary solution.

**Q141. What is the Substation Risk: Flood Defense program?**

A141. As I explained above, the Substation Risk: Flood Defense program was created following the third-party's flood risk analysis of the Company's Class C and D substations, following flooding events at the Company's substations, including the McGraw Substation flooding in 2021.

The Company's Class C and D substations<sup>39</sup> 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. As part of the flood risk analysis, the Company determined that five substations (Walker, Orchard, Madison, Frisbee, and Scotten), serving approximately 17,000 customers, were at elevated risk and required flood mitigation measures. To address the risk to these substations, the Company developed the Substation Risk: Flood Defense program to limit or prevent water intrusion in vulnerable substations by performing the following work at the five substations:

---

<sup>39</sup> 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.

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- 1 • Install one-way backflow prevention valves on existing sewer connected
- 2 dewatering systems;
- 3 • Install emergency dewatering pumps to discharge at ground level during sewer
- 4 backup events;
- 5 • Seal conduit to help prevent water penetration into the substation; and
- 6 • Replace existing primary pumps, at Frisbee, Madison, Scotten, and Orchard
- 7 substations.

8

9 The project is anticipated to be completed in 2025, and more details of this program  
10 can be found in Exhibit A-23, Schedule M5.

11

12 **Q142. What are the customer benefits of the Substation Risk: Flood Defense program?**

13 A142. The Substation Risk: Flood Defense program investments will reduce the risk of  
14 catastrophic failure at the five identified at-risk substations, thus reducing the risk of  
15 extended outages for approximately 17,000 customers (98% are considered vulnerable  
16 from an EJ perspective), as well as the costly subsequent repairs.<sup>40</sup>

17

18 **Q143. What should the Commission conclude with respect to the Substation Risk: Flood**  
19 **Defense program in this instant case?-**

20 A143. The MPSC should approve the Flood Defense program for cost recovery in the instant  
21 case because these investments are reasonable and prudent. As discussed in this section  
22 of my testimony, this project is necessary to respond to the substation flood analysis  
23 performed by installing back-flow prevention valves, emergency water pumps, replace  
24 existing primary pumps, at Frisbee, Madison, Scotten, and Orchard substations, and

---

<sup>40</sup> See Witness Kryscynski testimony for definition of vulnerable customer

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1 sealing conduit to reduce the risk of flooding causing catastrophic failure at the five  
2 identified substations which serve approximately 17,000 customers.

3

4 **A.2. Failed Equipment-Related Substation Risk Projects**

5 **Q144. Can you explain how failed equipment-related substation risk projects differ from**  
6 **the flood-related substation risk projects you just described?**

7 A144. While the Company's flood-related substation risk projects are tied to addressing  
8 substations that have experienced or are at risk of experiencing catastrophic failures  
9 caused by flooding, the Company's failed equipment-related substation risk projects  
10 address substations currently experiencing equipment failures that have different  
11 causes.

12

13 **Q145. Why was the Substation Risk: Apache project created?**

14 A145. A breaker position inside switchgear failed at the Apache Substation in 2015 which  
15 resulted in a significant area-wide outage affecting approximately 11,000 customers  
16 with 81% of affected customers being restored within 16 hours. The downtown  
17 business district of Troy, as well as surrounding commercial and residential areas were  
18 without electrical service for a prolonged period of time.

19

20 An assessment was performed after emergency repairs were made, which identified the  
21 remaining switchgear breakers were at-risk of a similar failure. A second catastrophic  
22 failure could result in the loss of all switchgear positions, and up to 16 MVA of stranded  
23 load. Stranded load occurs when customers cannot be restored by  
24 jumpering/transferring customers to an adjacent circuit or substation leading to  
25 prolonged customer outages across the entire substation area. In the example of

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1 Apache, while some load can be transferred to adjacent circuits, up to 16 MVA cannot  
2 be. The Substation Risk: Apache project was initiated to invest in appropriate  
3 replacements to prevent this potential second catastrophic failure.

4

5 **Q146. What is the scope of the Substation Risk: Apache project?**

6 A146. The scope of the Substation Risk: Apache project is to:

- 7 • Replace (1) at-risk 19-position switchgear with (2) new 12-position switchgear
- 8 • Replace (3) circuit switchers with S&C 2020 circuit switchers
- 9 • Build system cable termination on new switchgear for all 13 circuits
- 10 • Decommission the existing at-risk 19 position switchgear once load is cut over  
11 to new switchgear
- 12 • Install 12-5” conduit supporting substation exits
- 13 • Build (1) two-way manhole
- 14 • Build (9) three-way manholes
- 15 • Remove ~8,584 feet of old EPR (ethylene propylene rubber) and XLPE (cross-  
16 linked polyethylene) cable
- 17 • Install ~9,333 feet of new EPR cable
- 18 • Replace (19) disconnect switches with pole-top switches at the station cable  
19 poles

20

21 **Q147. What are the customer benefits of the Substation Risk: Apache Project?**

22 A147. The new switchgear will reduce the risk of catastrophic substation failures and  
23 extended duration area-wide customer outages. The replacement of one at-risk 19-  
24 position switchgear with two new 12-position switchgear will also provide load relief

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1 to Apache circuits that exceed day-to-day limits. The project is anticipated to be  
2 completed in 2026.

3

4 **Q148. What should the Commission conclude regarding the investment in the Substation**  
5 **Risk: Apache project in this instant case?**

6 A148. The Commission should approve the Substation Risk: Apache project investment  
7 because this project is reasonable, prudent, and is necessary to reduce the risk of  
8 another catastrophic switchgear breaker failure at the Apache substation potentially  
9 resulting in an extended duration outage for the nearly 11,000 customers served by the  
10 Apache substation.

11

12 **Q149. Why was the Substation Risk: Chestnut project created?**

13 A149. The Chestnut substation has a single 19-position switchgear that is a single point of  
14 failure. A switchgear failure could result in the loss of all switchgear positions and a  
15 potential stranded load of 35 MVA with limited jumpering options, which would affect  
16 approximately 6,000 customers across three cities. This type of potential failure is  
17 similar to the Apache substation failure described earlier in my testimony, which would  
18 result in a long-duration outage for the affected customers. The switchgear itself was  
19 evaluated to be at high risk of failure based on a combination of years in service (53  
20 years) and an equipment type that has experienced issues (GE air breaker). The  
21 Chestnut project was initiated to mitigate the combination of high equipment risk and  
22 up to 15 MVA of stranded customer load by replacing the single at-risk 19-position  
23 switchgear with two new 12-position switchgear.



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1      **Q150. What is the scope of the Substation Risk: Chestnut project?**

2      A150. The scope of the Substation Risk: Chestnut project is to replace one at-risk 19-position  
3                    switchgear with two 12-position switchgear, replace and relocate three capacitor banks,  
4                    install approximately 500 feet of 15-5" concrete encased duct bank, install  
5                    approximately 10,000 feet of EPR cable and associated branch and straight joints, and  
6                    install 17 OMNI-Rupters. More details of this project can be found in Exhibit A-23,  
7                    Schedule M5.

8

9      **Q151. What are the benefits of the Substation Risk: Chestnut project?**

10     A151. The new switchgear will reduce the risk of catastrophic substation failures and  
11                    extended duration area-wide customer outages and will provide increased capacity to  
12                    serve 18 distribution circuits, while the old configuration was only capable of serving  
13                    12 distribution circuits. The project is anticipated to be completed in 2026.

14

15     **Q152. Was investment in the Substation Risk: Chestnut project requested in previous**  
16                    **rate cases?**

17     A152. Yes. The Substation Risk: Chestnut project was included in Exhibit A-12, Schedule  
18                    B5.4 and Exhibit A-23, Schedule M4 exhibits for Case Nos. U-21297, U-20836, U-  
19                    20561, and U-20162.

20

21     **Q153. What should the Commission conclude with respect to the investment in the**  
22                    **Substation Risk: Chestnut project in this instant case?**

23     A153. The Commission should approve the Substation Risk: Chestnut project investment  
24                    because this project is reasonable, prudent, and necessary to reduce the risk of a  
25                    catastrophic switchgear breaker failure at the Chestnut substation potentially resulting

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1 in an extended duration outage for the 6,000 customers served by the Chestnut  
2 substation.

3

4 **Q154. Why was the Substation Risk: Savage Stranded Load project created?**

5 A154. Following the fire at Apache substation, DTE Electric engineering teams assessed  
6 similar switchgear across its service territory for risk potential. Savage substation was  
7 identified as having a high-risk switchgear that did not have connections to adjacent  
8 substations that would allow for jumpering of the load in the event of a failure of the  
9 switchgear. This lack of jumpering capabilities created the risk of stranded load in the  
10 event of failure which was determined to be approximately 30MVA of load.

11

12 **Q155. What is the scope of the Substation Risk: Savage Stranded Load project?**

13 A155. The scope of the Substation Risk: Savage project was to extend conduit and cable to  
14 feed seven new primary switch cabinets and establish tie points to adjacent circuits and  
15 substations. More details of this project can be found in Exhibit A-23, Schedule M5.

16

17 **Q156. What are the customer benefits of the Substation Risk: Savage Stranded Load**  
18 **project?**

19 A156. Installing switch cabinets and establishing underground connections in the area  
20 accomplished the primary goal of mitigating stranded load but also provided future  
21 benefits. The new switch cabinets offer spare positions for future load growth as well  
22 as operating flexibility between Savage, Lochdale, and Apache circuits in the event of  
23 failures on these circuits. The project was completed in 2024.

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1     **Q157. Why was the Substation Risk: Savage Switchgear Replacement project created?**

2     A157. The Savage substation has a single 16-position switchgear that is a single point of  
3         failure. This project is a separate and distinct from the Savage stranded load project  
4         mentioned earlier in my testimony. A switchgear failure could result in the loss of all  
5         switchgear positions and a potential stranded load of 30 MVA with limited jumpering  
6         options, which would affect approximately 3,000 customers throughout Troy. This type  
7         of failure would result in a long-duration outage for the affected customers. The  
8         switchgear has been determined to be at-risk of failure based on a review by the  
9         Company's equipment engineers. The combination of high equipment risk and high  
10        stranded customer load was why the Savage project was initiated. By splitting the  
11        existing single 16-position switchgear into two new separate 9-position switchgears,  
12        the equipment risk is reduced and the amount of potentially stranded load (15 MVA)  
13        due to a single point failure is also reduced.

14

15     **Q158. What is the scope of the Substation Risk: Savage Switchgear Replacement**  
16        **project?**

17     A158. The scope of the Substation Risk: Savage Switchgear Replacement project is to:

- 18         • Remove the existing parking area north of existing substation fence –  
19            approximately 7,800 sq. ft.
- 20         • Extend the substation fence approximately 300 feet
- 21         • Perform site preparation and below grade for an expanded substation yard
- 22         • Install concrete pads for new switchgear and three (3) 6 MVAR bus capacitor  
23            banks
- 24         • Install two (2) 9-position 2-high switchgear

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- 1 • Install conduit and system cable to existing circuit cables feeding Savage
- 2 circuits and neighboring circuits to enable jumper contingency
- 3 • Extend overhead lines 770 feet to establish two (2) portable ready locations
- 4 • Install two (2) sets of 3-333KVA regulators
- 5 • Decommission and remove an existing 1960's vintage continuous line-up of
- 6 one (1) 16-position switchgear.

7 This project is anticipated to be completed in 2027. More details of this project can be  
8 found in Exhibit A-23, Schedule M5.

9

10 **Q159. What are the benefits of the Substation Risk: Savage Switchgear Replacement**  
11 **project?**

12 A159. The new switchgear will reduce the risk of catastrophic substation failures and  
13 extended duration area-wide customer outages. It will also provide increased capacity  
14 to serve 12 distribution circuits while the old configuration was only capable of serving  
15 10 distribution circuits.

16

17 **Q160. Was investment in the Substation Risk: Savage Switchgear Replacement project**  
18 **requested in previous rate cases?**

19 A160. No. The Substation Risk: Savage Switchgear Replacement project is new and was not  
20 included in any prior rate cases.

21

22 **Q161. What should the Commission conclude with respect to the investment in the**  
23 **Substation Risk: Savage Switchgear Replacement project in this instant case?**

24 A161. The Commission should approve the Substation Risk: Savage Switchgear  
25 Replacement project investment because this project is reasonable, prudent, and

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1 necessary to mitigate the risk of a switchgear failure at Savage substation which would  
2 result in a potential 30 MVA of stranded load affecting 3,000 customers throughout  
3 Troy.

4

5 **Q162. Why was the Substation Risk: Belleville Switchgear Decommission project**  
6 **created?**

7 A162. In the beginning of 2020, DTE Electric's Engineering team identified the 4.8kV  
8 Belleville switchgear as being at end of life. Breakers inside the switchgear required  
9 multiple repairs over the course of 5 years and there are no breaker replacements if they  
10 were to fail. Control wiring inside the cubicle also required re-wiring which involved  
11 extended planned shutdowns. The Belleville substation did experience a switchgear  
12 failure in 2022 which led to the condemnation of Bus 11 and limited operability. The  
13 Company's equipment engineers determined that the switchgear at Belleville  
14 substation is at-risk of further failures and needs to be fully decommissioned.

15

16 **Q163. What is the scope of the Substation Risk: Belleville Switchgear Decommission**  
17 **project?**

18 A163. The scope of the Substation Risk: Belleville Switchgear Decommission project is to  
19 bypass Belleville's 4.8kV switchgear by installing an overhead NOVA triple-single  
20 recloser just outside of the substation, convert the 4.8kV portion of Belleville substation  
21 from a Class A to a Class T substation, and reconfigure the (3) load-carrying circuits  
22 and throw-over circuit into (2) load-carrying circuits. This project was completed in  
23 2024. More details of this project can be found in Exhibit A-23, Schedule M5.

Line  
No.

1     **Q164. What are the benefits of the Substation Risk: Belleville Switchgear Decommission**  
2     **project?**

3     A164. Decommissioning and removing the partially failed, at-risk 4.8kV switchgear at  
4     Belleville substation and then reconfiguring the distribution circuits has enabled  
5     continued service for approximately 1,300 customers. This work has reduced the risk  
6     of extended outages for these customers if the switchgear were to experience another  
7     failure in the future.

8

9     A future 4.8kV Conversion project at Belleville substation is addressed in Witness  
10    Stowe's testimony which will convert these circuits to 13.2kV and remove any  
11    remaining 4.8kV equipment at Belleville substation.

12

13    **Q165. Why was the Substation Risk: Voyager project created?**

14    A165. Voyager is an industrial substation serving an automotive industrial customer. The  
15    customer has experienced several interruptions due to the at-risk high side motor  
16    disconnects at Voyager substation.

17

18    **Q166. What is the scope of the Substation Risk: Voyager project?**

19    A166. The scope of the Substation Risk: Voyager project was to install four piers for future  
20    circuit switcher installation, install anchor bolts for future circuit switcher installation,  
21    and above-grade work to replace the motor disconnects with new circuit switchers that  
22    will be scheduled with the customer. More details of this project can be found in  
23    Exhibit A-23, Schedule M5.

Line  
No.

1     **Q167. What are the benefits of the Substation Risk: Voyager project?**

2     A167. The below grade work was completed during a planned customer shutdown to avoid  
3           unnecessary customer outages. This below grade work enabled quicker replacement  
4           of the at-risk equipment during a future project to replace this equipment and improve  
5           reliability and operability at Voyager substation. This project was completed in 2023.

6

7     **Q168. Why was the Substation Risk: Drexel project created?**

8     A168. Switchgear position I at Drexel substation experienced a failure in July 2016 which  
9           resulted in a fire and damaged several positions in the Drexel switchgear.  
10          Approximately 7,500 customers are normally served by Drexel substation and over  
11          3,000 customers were transferred to adjacent substations to restore service. Replacing  
12          the switchgear and restoring customers to their normal point of service will restore  
13          operability and reduce loading constraints in the area.

14

15    **Q169. What is the scope of the Substation Risk: Drexel project?**

16    A169. The scope of the Substation Risk: Drexel project in 2025 is to commission and load  
17          transfer all DC circuits, install the circuit switcher, remove existing switchgear from  
18          the substation, and install SCADA and network communication. More details of this  
19          project can be found in Exhibit A-23, Schedule M5.

20

21    **Q170. What are the benefits of the Substation Risk: Drexel project?**

22    A170. Completing the Drexel switchgear replacement project will restore the area to its  
23          normal configuration which reduces load on adjacent circuits and substations that have  
24          been temporarily serving Drexel customers since 2016. Decommissioning and

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1 removing the partially failed switchgear mitigates the risk of additional failures and  
2 extended outages for the area. The project is anticipated to be completed in 2025  
3

4 **Q171. What should the Commission conclude with respect to the investment in the**  
5 **Substation Risk: Drexel project in this instant case?**

6 A171. The Commission should approve the Substation Risk: Drexel project investment  
7 because this project is reasonable, prudent, and necessary to mitigate the risk of  
8 additional failures and extended outages for customers in this area.  
9

10 **Q172. Why was the Substation Risk: Seville project created?**

11 A172. Position B at Seville experienced a failure in 2023 and after a review by the Company's  
12 engineers was determined unrepairable. Approximately 1,500 customers have been  
13 temporarily transferred to adjacent circuits to continue service. No spare positions  
14 currently exist at Seville substation to restore the area to normal configuration;  
15 therefore, switchgear replacement is necessary.  
16

17 **Q173. What is the scope of the Substation Risk: Seville project?**

18 A173. The scope of the Substation Risk: Seville project is to:

- 19 • Replace one (1) failed 7-position switchgear with one (1) 9-position switchgear  
20 • Install new transformer secondary cables  
21 • Perform load transfers to re-establish Seville circuits to normal configuration

22 More details of this project can be found in Exhibit A-23, Schedule M5.



Line  
No.

1     **Q174. What are the benefits of the Substation Risk: Seville project?**

2     A174. Restoring the area to normal configuration will allow the Company to return all circuits  
3           to normal operating condition and restore system redundancy in the event of future  
4           outage events. Additionally, the new standard 9-position switchgear will provide two  
5           spare circuit positions for future use to support customer growth, as necessary.

6

7     **Q175. What should the Commission conclude with respect to the investment in the**  
8           **Substation Risk: Seville project in this instant case?**

9     A175. The Commission should approve the Substation Risk: Seville investment because this  
10           project is reasonable, prudent, and necessary to restore the Seville substation to a  
11           normal operating condition and return all circuits to loads that are within an acceptable  
12           range.

13

14    **Q176. Why was the Substation Risk: Hood project created?**

15    A176. The transformer at Hood skid-mount substation experienced two failures and after a  
16           review by the Company's engineers was determined unrepairable. Approximately  
17           2,000 customers have been temporarily transferred to adjacent circuits to continue  
18           service. A replacement transformer is not available for the skid mount substation to  
19           restore the area to normal configuration; therefore, the skid-mount substation  
20           replacement is necessary.

21

22    **Q177. What is the scope of the Substation Risk: Hood project?**

23    A177. The scope of the Substation Risk: Hood project is to:

24           

- Remove failed skid-mount substation and infrastructure

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- 1 • Construct a new two transformer substation consisting of two modular power
- 2 deliver centers (PDC)
- 3 • Construct a new two transformer (2-15/20/25MVA transformers, two modular
- 4 power delivery center) substation
- 5 • Extend approximately 220 feet of 2–5-inch conduit
- 6 • Extend approximately 720 feet of EPR cables
- 7 • Install (6) pole top switches (PTS) to support station cable poles
- 8 • Perform load transfers to re-establish Hood circuits to normal configuration

9 More details of this project can be found in Exhibit A-23, Schedule M5.

10

11 **Q178. What are the benefits of the Substation Risk: Hood project?**

12 A178. Restoring the area to normal configuration will enable the Company to return all

13 circuits, approximately 2,000 customers, to normal operating condition and restore

14 system redundancy in the event of future outage events. Additionally, the new

15 substation will provide increased capacity for the area, from 13 to 40 MVA and

16 supports Pontiac conversion by establishing capacity for two additional circuit

17 positions to transfer customers from the 8.3kV infrastructure.

18

19 **Q179. What should the Commission conclude with respect to the investment in the**

20 **Substation Risk: Hood project in this instant case?**

21 A179. The Commission should approve the Substation Risk: Hood investment because this

22 project is reasonable, prudent, and necessary to restore the Hood substation to a normal

23 operating condition and return all circuits to loads that are within an acceptable range.

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1     **Q180. Why was the Substation Risk: Waterman project created?**

2     A180. The Waterman project was initiated to address critical issues with DC grounds on a  
3         NERC (North American Electric Reliability Corporation) battery at Waterman  
4         substation. The DC ground on the battery could not be repaired due to the  
5         inaccessibility of grounded cables embedded in the concrete walls of the substation, an  
6         earlier design that is no longer used. These DC grounds jeopardized the reliability of  
7         protective equipment, hindering their proper operation. In order to comply with NERC  
8         Standard PRC-005 (Protection System, Automatic Reclosing, and Sudden Pressure  
9         Relaying Maintenance), which mandates corrective action for systems with DC  
10        grounds, the Company initiated this project.

11

12    **Q181. What is the scope of the Substation Risk: Waterman project?**

13    A181. The scope of the Substation Risk: Waterman project is to:

- 14           • Remove existing failed DC cables from (38) breaker positions
- 15           • Install cable trays for DC cable
- 16           • Install DC cables to (38) breaker positions
- 17           • Consolidate electrical buses to optimize space for breaker positions

18        More details of this project can be found in Exhibit A-23, Schedule M5.

19

20    **Q182. What are the benefits of the Substation Risk: Waterman project?**

21    A182. The Waterman project offers several benefits. By addressing the critical issue of DC  
22        grounds on a NERC battery, the project maintains the safety and reliability of the  
23        protective equipment, maintaining operation during fault conditions. Upgrading the DC  
24        system and relocating all DC cables onto accessible cable trays will facilitate easier  
25        maintenance and future inspections, reducing downtime and operational disruptions.

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1           Additionally, by abandoning the grounded cables and installing new DC cables, the  
2           project mitigates the risk of potential failures, improves overall system resilience, and  
3           maintains compliance with the NERC PRC-005 standard.

4

5           **Q183. What should the Commission conclude with respect to the investment in the**  
6           **Substation Risk: Waterman project in this instant case?**

7           A183. The Commission should approve the Substation Risk: Waterman investment because  
8           this project is reasonable, prudent, and necessary to restore the Waterman substation to  
9           a normal operating condition and maintain compliance with NERC PRC-005.

10

11           **B. Mobile Fleet Program.**

12           **Q184. What is the Mobile Fleet program?**

13           A184. The Mobile Fleet program includes investments to expand the Company's fleet of  
14           mobile generation (Figure 16) used to quickly restore temporary power to customers  
15           during major events such as substation failures and to support customers during  
16           planned construction work when field crews must deenergize electric equipment for  
17           safety reasons. In many major outage events, the mobile fleet allows for customer  
18           restorations even before repairs begin on the failed equipment. The mobile fleet  
19           includes portable generators, portable switchgear, portable substations, portable ISO  
20           equipment, portable poles, energy storage trailers and the controls that allow these  
21           assets to work together cohesively during planned and emergency outage events.

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1

**Figure 16. Portable Substation (left) & Mobile Generator (right)**



2

3 **Q185. How does the Mobile Fleet program benefit customers?**

4 A185. The Mobile Fleet program gives the Company a short-to-medium term solution to  
5 major outage events and allows the Company to perform planned work, such as  
6 preventative maintenance on single-tap substations, without requiring customers to  
7 experience an outage while the work is being performed.

8

9 Since the beginning of 2022 to the end of 2024, DTE Electric has experienced 109  
10 major events, not including Storm events, on the system, causing loss of power for a  
11 few hundred customers to over 10,000 customers. One example occurred at Snover  
12 Substation in 2023. The Snover Substation is a single transformer, two circuit  
13 substation. The single substation transformer failed, resulting in loss of load for  
14 approximately 1,100 customers for what could have been an extended outage. The load  
15 of the circuits could not be transferred to neighboring circuits due to the configuration  
16 of adjacent DTE Electric circuits and because the other adjacent circuits are owned by  
17 other electric providers. The Company's short-term solution was to deploy portable  
18 distributed generators to serve the load of the two circuits, restoring customers within  
19 hours. The medium-term solution required the Company to install a portable substation

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1 while permanent repairs were made at Snover Substation. The permanent repairs  
2 required several days to complete, so the short- and medium-term use of mobile  
3 equipment allowed customers to be restored to service faster. This example highlights  
4 both the significant challenges to addressing a major event failure and the important  
5 role the Mobile Fleet program plays in restoration of service to customers.

6

7 **Q186. What did the Commission conclude with respect to the Company's investments of**  
8 **its Mobile Fleet program in the Final Order in U-21534?**

9 A186. The Commission found there was "sufficient evidence on this record to allow cost  
10 recovery of this program in this case and support[ed] the company's attention to  
11 customers who are particularly vulnerable to the detrimental effects of power  
12 outages."<sup>41</sup>

13

14 **Q187. What Mobile Fleet program equipment is the Company planning to purchase in**  
15 **this instant case?**

16 A187. This request for the Mobile Fleet program is an extension of what was allowed for cost  
17 recovery in the last rate case. By continuing this approach, the Company's goal is to  
18 maintain the program's capability to effectively address current and future needs.

19

20 The Company made good progress on the building of Portable Diesel Generator 1  
21 (PDG1), performed the integration of portable generator controls to enhance  
22 functionality, and completed the portable switchgear in 2024.

---

<sup>41</sup> Case No. U-21534 Order dated January 23, 2025, p. 117

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1 The Company plans to complete the building of PDG1, complete the integration of  
2 portable controls, purchase additional connection skids and transformers, and integrate  
3 switchgear protection coordination capability in 2025.

4

5 The Company also plans the design and procurement of a low carbon fuel generator,  
6 hybrid DC generator or low carbon generator conversion, completion of the connection  
7 skids and transformers, portable controls enhancements, and phase balance controls in  
8 2026.

9 **C. Portable Generators**

10 **Q188. What is the Portable Generator program?**

11 A188. The Portable Generator program is a part of the Major Event Risk projects and is an  
12 investment the Company is undertaking to help reduce the length of extended outages  
13 to single customers during storm events. I mention it here solely because it is a part of  
14 Major Event Risk projects, but the program itself is addressed and supported by  
15 Company Witness Hill's testimony.

16

17 **IX. Pontiac Vaults**

18 **Q189. What is the current state of the Company's infrastructure that provides service**  
19 **to the City of Pontiac?**

20 A189. DTE Electric acquired the 8.3kV electrical system that serves the main portion of the  
21 city of Pontiac from Consumers Energy in the 1980s. The Pontiac system includes a  
22 set of downtown underground vaults, constructed in a way that is difficult to maintain  
23 and does not meet current safety standards. The Pontiac 8.3kV system is fed by four  
24 substations (Barlett, Paddock, Rapid Street, and Stockwell) and 18 distribution circuits,  
25 but is surrounded entirely by 13.2kV circuits. Thus, when there is a major failure, the

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1 Company is unable to quickly restore customers by transferring load to adjacent DTE  
2 Electric circuits.

3

4 Additionally, the 8.3kV system uses a non-standard voltage that the Company does not  
5 use in any other area of its service territory and is now considered an obsolete system.  
6 Replacement parts are no longer available for 8.3kV breakers and other substation  
7 equipment due to their obsolescence, leading to extended customer interruptions and  
8 leaving the system in an abnormal state for longer durations when work must be  
9 completed (preventative or reactive). Pontiac has also seen a gradual increase in load  
10 demand over the past several years. In response to these factors, the Company created  
11 a plan to convert the four 8.3kV substations and corresponding distribution circuits to  
12 13.2kV, as explained in Company Witness Stowe's testimony.

13

14 My testimony addresses the Pontiac 8.3kV system's underground vaults, which  
15 primarily house the equipment that provides service to the downtown business district,  
16 including hospitals and city official buildings.

17

18 **Q190. What is included in the Pontiac Vaults program?**

19 A190. The Pontiac Vault Program includes projects that upgrade the existing underground  
20 equipment with modern equipment that is submersible, and arc sealed. This work  
21 includes replacing damaged vaults, replacing at-risk and end-of-life equipment in the  
22 vaults, replacing seven miles of existing non-standard cable, and installing SCADA  
23 monitoring equipment.



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1 **Q191. How does the Pontiac Vault program benefit customers?**

2 A191. The Pontiac Vault program is an integral part of the larger 8.3kV Pontiac Conversion  
3 program addressed by Company Witness Stowe; an initiative that will benefit  
4 customers by improving reliability, allowing faster outage restoration, and increasing  
5 electric capacity available to serve the city of Pontiac. Additionally, the Pontiac Vaults  
6 program improves safety for Company operators and the public and replaces at-risk,  
7 aging, non-standard equipment that poses a reliability risk to downtown Pontiac. The  
8 original underground vaults contained live front equipment and outdated, insufficient  
9 working clearances. Proper working clearances are crucial to mitigate electrical  
10 hazards for personnel working in the vault.

11

12 **X. Short Cycle Maintenance Programs for Low Reliability Circuits**

13 **A. Frequent Outage Programs (CEMI)**

14 **Q192. What programs are included in Frequent Outage Programs?**

15 A192. In addition to strategic programs and projects to support overall grid reliability, the  
16 Company has shorter term programs to address targeted pockets of the grid where  
17 customers have experienced multiple outages. There are two primary programs under  
18 Frequent Outage programs: the Customer Excellence (CE) program and the Strategic  
19 Reliability Improvement program (SRIP).

20

21 The CE program was established to provide rapid solutions to small pockets of  
22 customers experiencing poor reliability. These customers are identified as experiencing  
23 four sustained outages (SAIFI > 4.0), or nine momentary outages (MAIFI > 9.0) per  
24 year. The prioritization method for circuits included in the CE program relies on  
25 Advanced Metering Infrastructure (AMI) data to identify these customers on a rolling

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1 12-month basis and is designed to address issues more rapidly than other programs  
2 which rely on the annual analysis of reliability events. In addition to reliability event  
3 data, the prioritization also includes an evaluation of the time since the area's last tree  
4 trim was completed, any other planned work on the circuits, as well as customer  
5 complaints.

6

7 Upon identification of a circuit that meets the CE prioritization criteria and is selected  
8 for construction, the Company conducts a field patrol to assess both equipment and tree  
9 conditions impacting reliability. After the patrol, the scope of work is developed for  
10 the identified equipment and tree-related problems. In addition to the damaged or failed  
11 equipment replacements and tree trimming, the scope of work also includes checking  
12 operating equipment to ensure it is functioning properly, conducting fault studies to  
13 ensure fuses are properly sized, and installing additional equipment, such as reclosing  
14 devices and animal guards, to prevent future outages. On average, the solutions require  
15 investments between \$60,000 and \$80,000 per circuit to implement.

16

17 The SRIP program performs improvements to either portions of a circuit (customer  
18 pockets), or entire circuits as appropriate. The primary distinctions between the CE and  
19 the SRIP programs are that circuits are normally selected for the SRIP program based  
20 on both a 12-month and a three-year average circuit SAIDI and SAIFI performance,  
21 MPSC complaints, and regional expertise on customer needs. In addition, the scope of  
22 work performed under the SRIP program is more comprehensive and typically requires  
23 investments between \$250,000 and \$300,000 per circuit to implement.

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1 **Q193. What is the Company's Pre-Summer Storm Strengthening (PS3) process?**

2 A193. Beginning in 2021 after a summer with a high number of storms and associated  
3 customer outages, the Company began an annual process of analyzing the performance  
4 data of all circuits following each summer storm season. This analysis identifies circuits  
5 predicted to have the worst reliability performance. The PS3 process allocates circuits  
6 to multiple programs such as Tree Trim, PTMM, CE, SRIP, and 4.8kV Hardening so  
7 that they receive improvements before the subsequent summer storm season.

8

9 **Q194. Has the Company continued the Pre-Summer Storm Strengthening process of**  
10 **identifying circuits that are at higher risk during storms and performing**  
11 **investments on them?**

12 A194. Yes. The Company has continued this process. For 2024, work was performed on 166  
13 circuits within the Frequent Outage (CEMI) programs. The Company is planning to  
14 work on 137 and 130 circuits in 2025 and 2026, respectively (Table 21).

15

16 **Table 21. Frequent Outage Programs (CEMI) 2024-2026**

|                                           | 2024<br>Actual | 2025<br>Forecast | 2026<br>Forecast |
|-------------------------------------------|----------------|------------------|------------------|
| CE Circuits                               | 115            | 110              | 90               |
| SRIP Circuits                             | 61             | 27               | 40               |
| <b>Total Frequent<br/>Outage Circuits</b> | <b>166</b>     | <b>137</b>       | <b>130</b>       |

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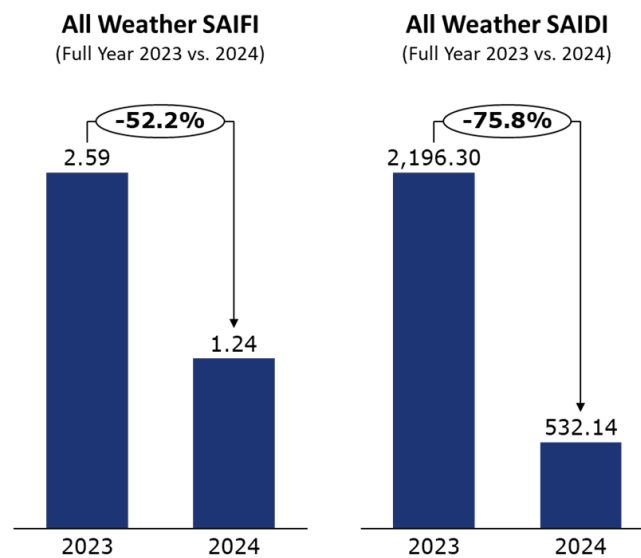
1 **Q195. How do Frequent Outage programs (CEMI) benefit customers?**

2 A195. Frequent Outage programs (CEMI) perform circuit improvements that increase electric  
3 service reliability for customers who have experienced recent poor reliability. The  
4 Company measures the reliability of the circuits selected for the Frequent Outage  
5 (CEMI) program before and after the work is completed.

6

7

**Figure 17. Frequent Outage Programs (CEMI) All Weather**



8

9 Figure 17 shows reliability data before and after the work was performed and calculated  
10 as it was in Case No. U-21534. Weather is variable year to year and can impact  
11 comparisons of circuit performance; however, circuits that underwent Frequent Outage  
12 (CEMI) work showed a 52.2% improvement in All Weather SAIFI and a 75.8%  
13 improvement in All Weather SAIDI when comparing 2023 to 2024.

14

15 **Q196. Does this complete your direct testimony?**

16 A196. 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-21860

QUALIFICATIONS  
AND  
DIRECT TESTIMONY  
OF  
RYAN M. STOWE

**DTE ELECTRIC COMPANY**  
**QUALIFICATIONS AND DIRECT TESTIMONY OF RYAN M. STOWE**

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1   **I. Background & Qualifications**

2   **Q1.   Please state your name, business address, and position of employment.**

3   A1.   My name is Ryan M. Stowe (he/him/his). My business address is One Energy  
4           Plaza, Detroit, Michigan, 48226, and I am employed by DTE Electric Company  
5           ("DTE Electric" or the "Company") as the Vice President of Reliability Operations.

6

7   **Q2.   On whose behalf are you testifying?**

8   A2.   I am testifying on behalf of DTE Electric.

9

10   **Q3.   Please summarize your educational background and certifications or**  
11       **professional memberships.**

12   A3.   I received a Bachelor of Science Degree in Chemical Engineering from Michigan  
13           Technological University. I received a Master of Business Administration from the  
14           University of Michigan. I am a member of the Association of Edison Illuminating  
15           Companies serving on the Power Delivery Committee and a member of the Edison  
16           Electric Institute serving on the National Response Executive Committee. In  
17           addition, I was trained in the Toyota Production System continuous improvement  
18           methodologies and Lean & Six Sigma, including Black Belt Certification.

19

20   **Q4.   Please summarize your professional experience.**

21   A4.   I began my career with Dart Container in 1995, a consumer packaging company as  
22           a process engineer. I then moved to the architectural, engineering, and construction  
23           firm, Earth Tech. I worked there from 1998-2000 as a process engineer. In 2000, I  
24           began work as plant manager for Adhesives Systems Inc. where I was responsible  
25           for the packaging adhesive production system and workforce.

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1 I joined DTE Energy in 2003 as a Senior Strategist and became a continuous  
2 improvement (“CI”) expert in 2004. In this role, I led the development of CI culture  
3 in Distribution Operations. After a series of roles with increasing responsibility, I  
4 was promoted to Manager of Performance Management in 2006 where I was  
5 responsible for performance metrics and strategy planning. In 2007, I assumed the  
6 role of Service Center Manager responsible for leading field personnel in day-to-  
7 day operation and maintenance of the electric distribution system.

8

9 In 2010, I was promoted to Director of Substation Operations. As Director of  
10 Substation Operations, I was responsible for safe and reliable operation of all the  
11 substations within the DTE Electric service territory. In 2011, I assumed the role of  
12 Director of Fleet & Facilities responsible for capital asset preservation and strategic  
13 planning for the DTE Electric facilities portfolio. In 2013, I assumed the role of  
14 Director of Service Operations responsible for day-to-day operations of field  
15 personnel including storm outage restoration, wire down response, preventative and  
16 corrective maintenance, and new customer connections.

17

18 In 2017, I was promoted to Executive Director of Distribution Operations. In this  
19 role, I oversaw the implementation of the Incident Command System (“ICS”) to  
20 enhance response to large-scale outages. In 2019, I was promoted to Vice President  
21 of Distribution Operations. In this role I oversaw Regional Customer Operations  
22 (“RCO”), the System Operations Center (“SOC”), the Company’s vegetation  
23 management, scheduling and work management, logistics, and execution of the  
24 distribution operations capital work portfolio.

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1 In 2023, I assumed the role of Vice President of Distribution Operations Strategic  
2 Capital Delivery within the newly-formed Project Management Office (“PMO”).  
3 In this role, I led strategic operational initiatives for electric grid buildout  
4 encompassing grid automation, voltage upgrades, and infrastructure modernization.  
5 In 2024, I assumed my current role as Vice President of Reliability Operations  
6 within Distribution Operations.

7

8 **Q5. What are your current duties and responsibilities?**

9 A5. As Vice President of Reliability Operations, I lead a team responsible for ensuring  
10 the optimal performance and longevity of DTE Electric’s distribution assets. I  
11 oversee Substation Operations, Asset & Work Management, and the Company’s  
12 Reliability Center of Excellence organizations. Additionally, I oversee asset  
13 lifecycle health and condition monitoring, aligning integrated work management  
14 processes to minimize costs and maximize benefits. My role involves leveraging  
15 data analytics and advanced modeling to identify reliability improvements and  
16 guide strategically focused grid upgrade programs. I also manage the daily  
17 operations and maintenance of 650 DTE Electric-owned substation facilities, so  
18 that they deliver on the highest standards for reliable power delivery and  
19 operational efficiency.



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1 **II. Overview & Executive Summary**

2 **Q6. What is the purpose of your testimony?**

3 A6. The purpose of my testimony is to support, as reasonable, prudent, and necessary,  
4 the historical capital expenditures for 2023 and the projected capital expenditures  
5 for the 24-month bridge period between January 1, 2024, through December 31,  
6 2025, and through the 12-month projected test period ending December 31, 2026,  
7 in the distribution strategic investment category of the Infrastructure Redesign and  
8 Modernization pillar.

9  
10 **Q7. How is your testimony organized?**

11 A7. Following the introductory material above and the executive summary material  
12 below, my testimony is organized by programs within the Infrastructure Redesign  
13 and Modernization pillar as follows:

14 III. 4.8kV Conversion Programs

15 A. 4.8kV Conversion Program

16 B. 4.8kV Isolation (“ISO”) Conversion Program

17 IV. City of Detroit Infrastructure (“CODI”) Conversion Program

18 V. 8.3kV Pontiac Conversion Program

19 VI. System Loading Projects

20 VII. Subtransmission Redesign & Rebuild Program

21 VIII. Strategic Undergrounding (“SUG”) Program

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1 **Q8. Are you sponsoring any exhibits in this proceeding?**

2 A8. Yes. I am sponsoring the following exhibits:

3

| 4  | <u>Exhibit</u> | <u>Schedule</u> | <u>Description</u>                                 |
|----|----------------|-----------------|----------------------------------------------------|
| 5  | A-12           | B5.4            | Projected Capital Expenditures – Distribution Plan |
| 6  |                |                 | (Pages 1, 2, 11-13, and 16-23)                     |
| 7  | A-12           | B5.4.8          | Electric Rate Case (ERC) and Infrastructure        |
| 8  |                |                 | Recovery Mechanism (IRM) Revenue Recovery          |
| 9  |                |                 | Partition                                          |
| 10 | A-23           | M6              | Distribution Plant Capital Project Detail –        |
| 11 |                |                 | Infrastructure Redesign and Modernization          |

12

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

14 A9. Yes, and they are.

15

16 **Q10. Can you explain the focus and goals of the Company's Infrastructure Redesign**  
17 **and Modernization pillar?**

18 A10. The Infrastructure Redesign and Modernization pillar focuses on rebuilding and  
19 modernizing the Company's nearly century-old grid to support long-term grid  
20 needs; specifically, the distribution and subtransmission segments of the grid. The  
21 programs and associated investments within this pillar are designed to add capacity  
22 and increase operational capability, while enhancing distribution system safety,  
23 reliability, and resiliency for customers. DTE Electric's Infrastructure Redesign  
24 and Modernization pillar investment strategy also focuses on eliminating loading  
25 constraints and redesigning and rebuilding the subtransmission system to provide

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1 operational redundancy and address a lack of capacity on portions of the  
2 Company's grid.

3  
4 Further, the investments in this pillar are essential to meeting the evolving needs of  
5 customers and their interactions with the grid, including adoption of electric  
6 vehicles (EVs) and other forms of electrification, as well as distributed energy  
7 resources (DER). In sum, the investments are vital to support the continued  
8 resurgence of the city of Detroit and to provide the needed energy to ensure a bright  
9 future for Michigan.

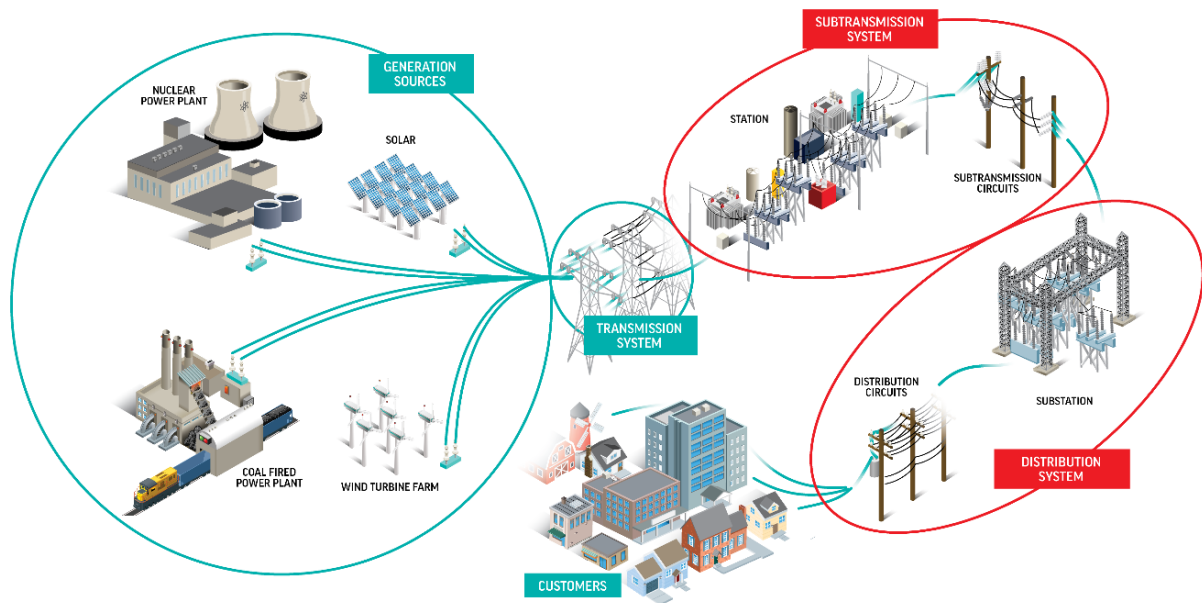
10

11 **Q11. What grid investment areas are included in the Infrastructure Redesign and**  
12 **Modernization pillar?**

13 A11. As I noted above, the Infrastructure Redesign and Modernization pillar focuses on  
14 both the distribution and subtransmission segments of the grid. The distribution  
15 system is designed to distribute electricity from a substation to customers, while  
16 the subtransmission system consists of the infrastructure that connects the  
17 distribution system to the transmission system. Figure 1 below illustrates the  
18 electrical system generally and points out the portions that are considered the  
19 distribution and subtransmission systems.

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1

**Figure 1 Electrical System Overview**



The Company's associated proposed grid investments for the distribution and subtransmission systems, highlighted in the red circles in Figure 1, are divided into programs, as I discuss in my testimony below.

The Company's distribution system is comprised of transformers, breakers, poles, pole-top hardware, conductors, and cables at primary voltages of 4.8kV, 8.3kV, and 13.2kV. In analyzing the long-term grid needs, the Company identified specific challenges associated with the aged 4.8kV and 8.3kV circuits, such as capacity, safety, reliability and resiliency, and developed a conceptual plan to convert 4.8kV and 8.3kV grid infrastructure to a higher voltage. Additionally, the Company has in recent years experienced an increased number of weather events of greater severity. Weather impacts, aged electrical infrastructure, and the need to support current and future load growth require an updated, higher voltage, hardened, and

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1 resilient grid. To address these concerns, the Company developed the 4.8kV  
2 Conversion Programs, the CODI Conversion Program, and the 8.3kV Pontiac  
3 Conversion Program.

4  
5 The conversion projects within these Programs update all substation and  
6 distribution equipment to the latest standards for improved safety, reliability, and  
7 resiliency at an area level of the grid while also adding capacity to the associated  
8 circuits. The modern equipment also allows for greater redundancy by reducing  
9 the size of customer outages by automatically jumpering<sup>1</sup> load to adjacent circuits.  
10 Conversion projects also reduce outage restoration time by pinpointing the trouble  
11 location without requiring line crews to patrol the entirety of the circuit.

12  
13 For substations where capacity is a concern, the Company developed the System  
14 Loading Projects to address those capacity needs. More specifically, the System  
15 Loading Projects focus on relieving system overloads, improving reliability, and  
16 adding capacity—mostly on the 13.2kV distribution system.

17  
18 Turning to the subtransmission system, the Company's current subtransmission  
19 system has voltages of 24kV, 40kV, and 120kV.<sup>2</sup> The Company's Subtransmission  
20 Redesign & Rebuild Program investments focus on this critical upstream feed to  
21 the distribution system. Whereas a fault on the distribution system can impact a  
22 single customer, circuit, or a few circuits, a fault on the subtransmission system can  
23 impact multiple substations and multiple circuits, affecting in some cases tens of

---

<sup>1</sup> 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.

<sup>2</sup> Generally speaking, the 120kV subtransmission elements are radial components.

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1 thousands of customers.<sup>3</sup> These projects focus on adding capacity and improving  
2 the reliability & redundancy of the subtransmission system.

3

4 The Company's Subtransmission Redesign & Rebuild Program investments also  
5 address system planning criteria violations that cause loading constraints and loss  
6 of redundancy and reliability issues where tree trimming and pole-top maintenance  
7 have not resolved those performance concerns. While distribution conversion  
8 projects address complete circuits, subtransmission projects focus on addressing  
9 only those portions of the circuit where improvements are needed. Investments in  
10 the subtransmission system, therefore, eliminate many distribution system  
11 constraints, improve existing customer reliability, and address future loading  
12 constraints.

13

14 Summary level Capital investment details for the programs in the Infrastructure  
15 Redesign and Modernization pillar are provided in Exhibit A-12, Schedule B5.4,  
16 pages 11-13 and Exhibit A-23, Schedule M6. Also included in Exhibit A-12,  
17 Schedule B5.4 for this category is AFUDC on page 16 and plant activity on pages  
18 17-23.

19

20 **Q12. How does the Infrastructure Redesign & Modernization pillar relate to the**  
21 **Company's Distribution Operations Business Unit's investment strategy?**

22 A12. As Company Witnesses Chiu and Kryscynski explain in their direct testimonies,  
23 the Company's Distribution Operations Business Unit ("Distribution Operations")  
24 identified near-term and longer-term initiatives to address capacity needs, enhance

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<sup>3</sup> Each subtransmission circuit serves one or more distribution substations, supporting anywhere from 1 to 14,600 customers

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1 safety, and improve reliability and resiliency for customers. The strategic  
2 investments associated with those initiatives are divided across four pillars, one of  
3 which is the Infrastructure Redesign & Modernization pillar. This pillar is  
4 comprised of several programs designed to modernize, convert and consolidate the  
5 Company's existing 4.8kV and 8.3kV systems to the higher 13.2kV distribution  
6 voltage level, address loading constraints (both at the distribution level in terms of  
7 system loading and at the subtransmission circuit level), and redesign and rebuild  
8 the subtransmission system. All programs in this pillar improve safety, modernize  
9 technology, refine system maintenance efficiencies, and address load constraints  
10 and improve reliability.

11  
12 Additionally, the Company continues to investigate undergrounding pilot programs  
13 as part of the Infrastructure Redesign & Modernization pillar. The pilot programs  
14 are used to continue to expand the Company's learnings in undergrounding existing  
15 overhead infrastructure using different design solutions for various circuit  
16 topologies across its service territory in urban, suburban, and rural environments.  
17 The Company is using these pilot programs to determine best design solutions  
18 while continuing to reduce implementation cost. These pilot programs are further  
19 addressed in the SUG Program section of my testimony.

20  
21 **Q13. Can you outline the programs that are part of the Infrastructure Redesign and**  
22 **Modernization pillar?**

23 A13. Yes, the Company developed the 4.8kV Conversion Programs, which include the  
24 4.8kV Conversion Program and the 4.8kV ISO Conversion Program. Additionally,  
25 the Company developed the CODI Conversion and the 8.3kV Pontiac Conversion

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1 Programs. Each conversion program is discussed in its allocated section of my  
2 testimony. After explaining the conversion programs, I turn to System Loading  
3 Projects, the Subtransmission Redesign & Rebuild Program, and the SUG Program.  
4

5 **Q14. What are the investment levels associated with each program discussed in your**  
6 **testimony?**

7 A14. Table 1 below summarizes the investment levels for each program supported by  
8 my testimony.  
9

10 **Table 1 Summary of Infrastructure Redesign and Modernization Pillar Investments**  
11 **(\$M)**

|                           | <b>2023</b>  | <b>2024</b>  | <b>2025</b>  | <b>2026</b>  |
|---------------------------|--------------|--------------|--------------|--------------|
| 4.8kV Conversion          | 46.3         | 89.5         | 37.0         | 105.8        |
| 4.8kV ISO                 | 4.4          | 4.3          | 5.3          | 18.0         |
| CODI                      | 92.9         | 72.1         | 38.4         | 135.0        |
| 8.3kV Pontiac Conversions | 10.2         | 19.6         | 5.2          | 20.7         |
| System Loading            | 14.2         | 24.9         | 44.6         | 70.5         |
| Subtransmission R&R       | 73.2         | 44.6         | 46.0         | 19.0         |
| SUG Program               | 3.0          | 11.4         | 0            | 14.0         |
| <b>Total</b>              | <b>244.1</b> | <b>266.3</b> | <b>176.4</b> | <b>383.0</b> |



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1 **III. 4.8kV Conversion Programs**

2 **Q15. What programs are part of the 4.8kV Conversion Programs?**

3 A15. The 4.8kV Conversion Program and the 4.8kV ISO Conversion Program fall under  
4 the larger umbrella of 4.8kV Conversion Programs. Both programs address  
5 capacity while upgrading the distribution system with current construction  
6 standards to enhance safety and improve reliability, operability, and resiliency.

7

8 **Q16. Are the capital expenditures included as part of the 4.8kV Conversion**  
9 **Programs in this case like the capital expenditures in the 4.8kV Conversion**  
10 **Programs that the Commission found reasonably supported by the Company**  
11 **in Case No. U-21534?**

12 A16. Yes, the proposed capital expenditures included as part of the 4.8kV Conversion  
13 Programs in this case are a continuation of the capital expenditures the Commission  
14 found reasonably supported by the Company in Case No. U-21534.<sup>4</sup>

15

16 **Q17. Please describe the Company's original 4.8kV distribution system.**

17 A17. The Company's original distribution system was designed nearly a century ago with  
18 standards of the time that included an ungrounded delta configuration with banked  
19 secondary and distribution voltage of 4.8kV, as shown in Figure 2. It is a three-  
20 phase design with no neutral for the distribution circuits. Due to this design  
21 configuration, when a single conductor comes down on a 4.8kV system the  
22 conductor most likely will remain energized until addressed by the Company,  
23 which can create a hazard. The wye design, in contrast, is a four-wire design, with  
24 three conductor wires, one for each phase, plus one neutral wire. In most cases, the

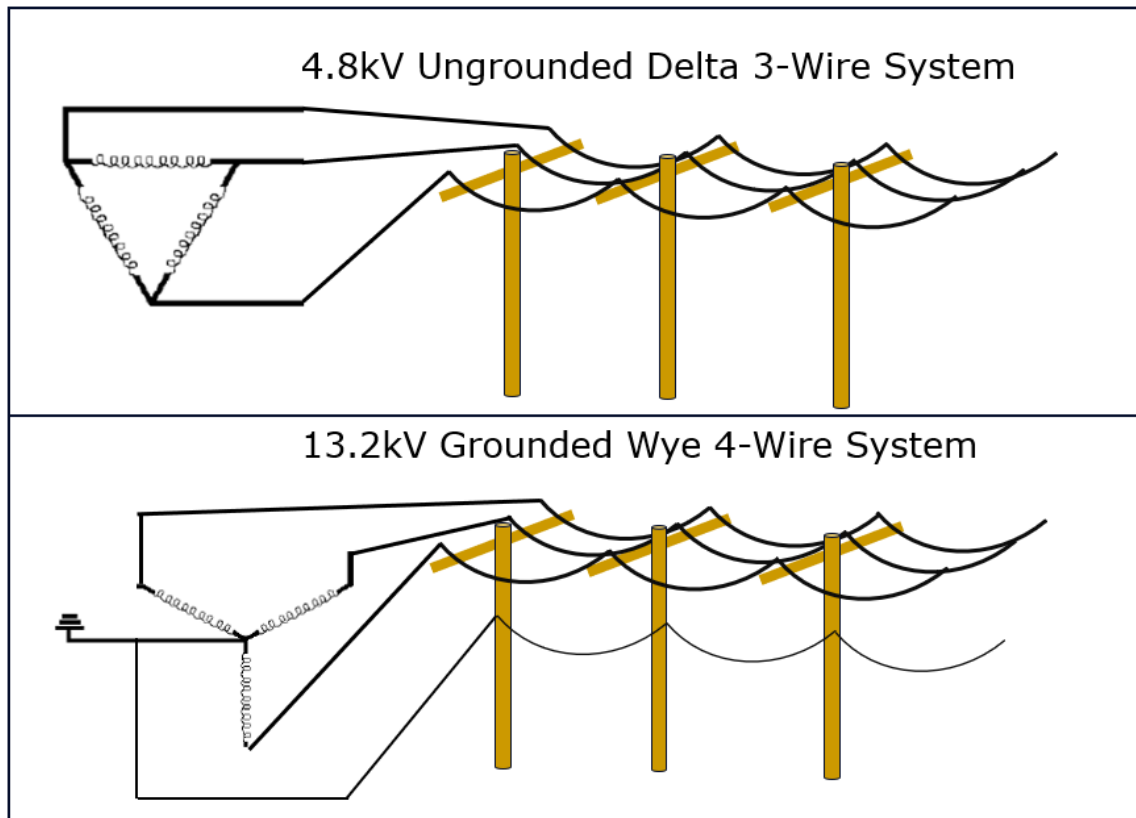
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<sup>4</sup> U-21534 - Commission Order, January 23, 2025, pp. 127.

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grounded wye four-wire design eliminates the hazard associated with a single conductor coming down.

**Figure 2 Comparison of 3-wire and 4-wire distribution circuit**

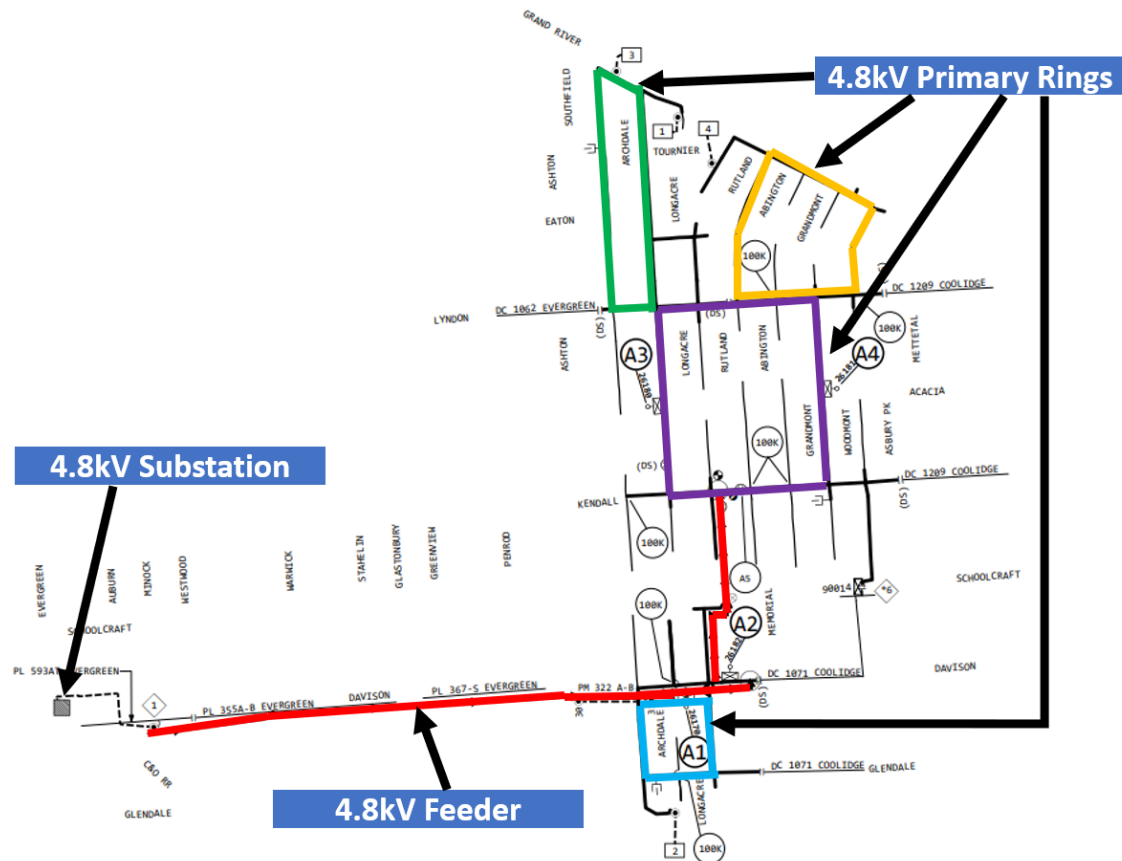


The initial design of the 4.8kV system predominantly used small copper (#2CU and #6CU) conductors which have lower current carrying capacity and mechanical strength properties versus the current larger and more robust design standard. To overcome the challenges inherent with small wire copper conductor, multiple paralleled sections of overhead wire were used to create what is referred to as “4.8kV rings,” as shown in Figure 3. With the 4.8kV ring design, there is bi-directional power flow within each ring making it challenging to install system protection devices. Further, the 4.8kV ring design can result in a large voltage drop

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to customers at the end of 4.8kV circuits if load was continuously tapped near the beginning of the circuit. For that reason, long untapped sections of overhead called “4.8kV Feeders” were constructed to a circuit’s load center to alleviate this issue.

**Figure 3 Multiple 4.8kV circuits topology**

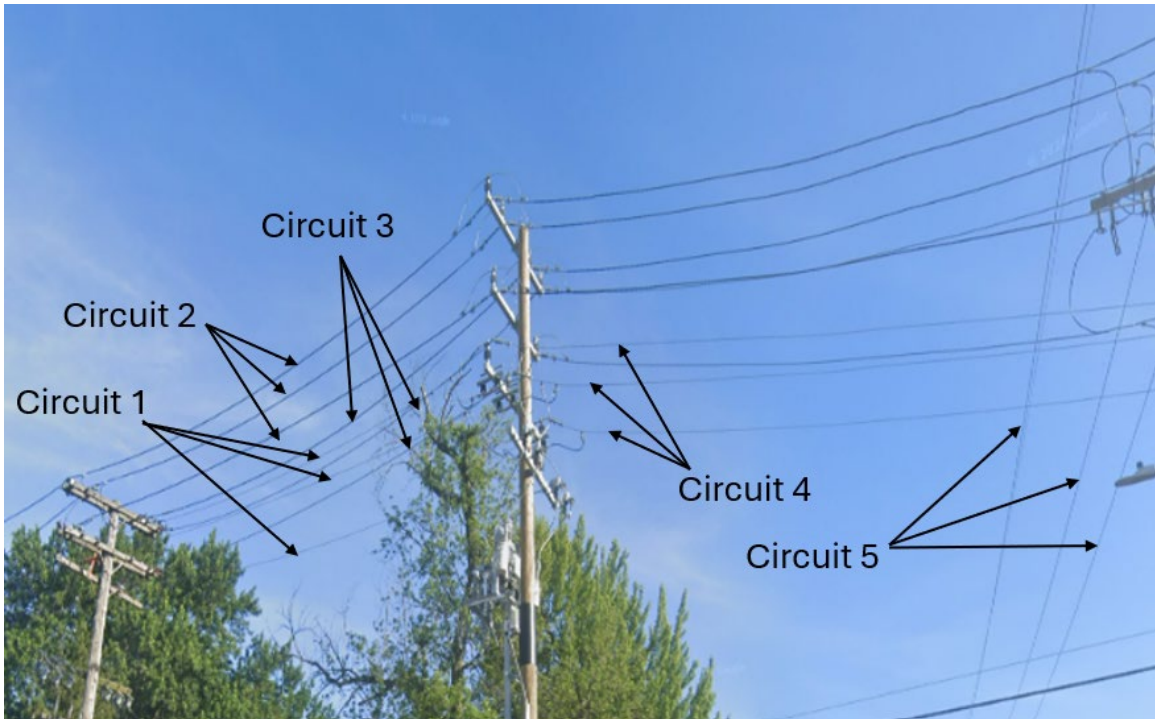


Additionally, due to the inherent lower voltage of the 4.8kV system, many circuits are needed to feed a geographical area when compared to the higher voltage 13.2kV system. The inherent lower voltage coupled with the 4.8kV circuit design characteristics, such as feeders and rings, results in multiple circuits being constructed on the same pole, as shown in Figure 4 below. Over time, this approach has become a system risk as a single wire down from one circuit can affect the other

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circuits on the same pole resulting in multiple circuits being placed out of service, thus impacting many customers.

**Figure 4 Multiple 4.8kV circuits on same poles**



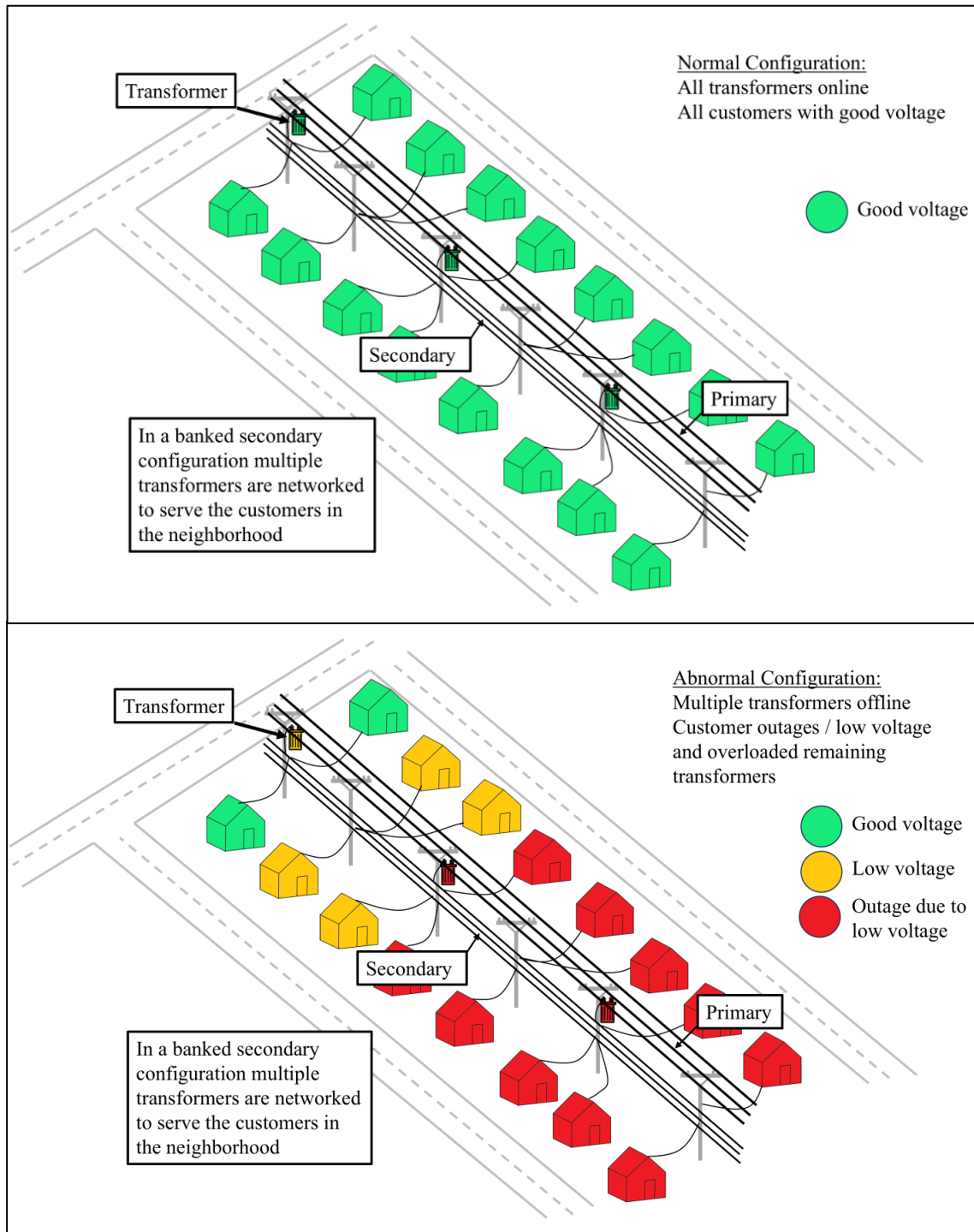
In most neighborhoods, the 4.8kV system was constructed in rear lot right-of-way for aesthetic reasons since it utilized overhead poles and wires. Initially, right-of-way truck access was readily available through municipally maintained alleys in many areas, including much of Detroit. Much of this right-of-way truck access is no longer as readily available due to alley maintenance abandonment.

Additionally, on the secondary portion of the system, a banked secondary system was the design standard at the time the 4.8kV system was constructed. This design includes multiple transformers interconnected through secondary fusing to provide power to a local area of customers. This design makes troubleshooting difficult for

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- 1 the line crews in the field and, for that reason, is not the Company's current design
- 2 standard. This secondary system design configuration, as shown in Figure 5, results
- 3 in low voltage to the customers when a secondary fuse blows that may further result
- 4 in cascading transformer failures and secondary wire downs.

**Figure 5 Bank Secondary Configuration**



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1 **Q18. Can you describe in more detail the challenges of the original 4.8kV**  
2 **distribution system related to capacity, safety, reliability, and operability?**

3 A18. Yes. Power capacity of the 4.8kV system circuit is limited due to the relatively low  
4 voltage class for a primary distribution system, as determined by the power  
5 equation for a three-phase circuit.<sup>5</sup> Therefore, for two circuits with similar amp  
6 ratings of equipment, including, but not limited to substation transformers and  
7 conductor or cable size, the load capacity of a 4.8kV distribution circuit for example  
8 is 2.75 times lower than load capacity of a 13.2kV circuit. Due to this lower voltage  
9 design, many 4.8kV circuits are needed to feed the load of a geographical area  
10 typically constructed on the same poles, as previously discussed above. On many  
11 4.8kV circuits, this constraint impacts the Company's ability to connect new  
12 customers or facilitate load growth of existing customers all else being equal.

13  
14 As I explained above, the large majority of 4.8kV distribution infrastructure was  
15 constructed in the Company's service territory post-World War II using small  
16 copper conductor (#2CU and #6CU) which limits emergency capacity available to  
17 transfer loads to adjacent circuits during outages resulting in customers being out  
18 of power until the trouble on their circuit is resolved.

19  
20 As stated above, the 4.8kV ungrounded delta design can create a public hazard  
21 when a single conductor comes down. Per this system design, there is no direct  
22 path to ground and a downed wire may only create a fault current that is not much  
23 larger than typical load. Due to this low fault current condition, the circuit

---

<sup>5</sup> Power (three-phase circuit load capacity) = Voltage (V) x Current (I) x  $\sqrt{3}$

Representative example using equipment with a 250A rating:

4.8kV system load capacity = 4,800V x 250A x  $\sqrt{3}$  = 2,078,261 Volt-amperes  $\approx$  2.08 MVA

13.2kV system load capacity = 13,200V x 250A x  $\sqrt{3}$  = 5,715,768 Volt-amperes  $\approx$  5.72 MVA

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1 protective devices (e.g., fuses, breakers) cannot detect and clear this hazard.  
2 Therefore, single downed conductors on an ungrounded 4.8kV delta system most  
3 likely will remain energized until addressed by the Company. Additionally, the  
4 existing 4.8kV system is more susceptible to wire-downs due to the small copper  
5 (#2CU and #6CU) conductors, which are weaker in strength compared to the  
6 current higher standard wires, and in many cases have deteriorated and weakened  
7 by age and the annealing effects of thermal cycling.

8

9 The reliability of the 4.8kV system, both in terms of outages (frequency and  
10 duration) and power quality, impacts the customer experience. When originally  
11 constructed, the 4.8kV system was modern, accessible, and reliable for a customer  
12 base with a much lower electrical demand. Driven by a combination of the age of  
13 the system, inaccessibility of infrastructure, and increasing customer demands, the  
14 4.8kV system is no longer a reliable design choice.

15

16 In addition to its lower capacity and reliability constraints, the 4.8kV system limits  
17 the operability for the Company. Smaller wire size and lower circuit/substation  
18 ratings limit the ability to reconfigure the system to restore customers in adjacent  
19 areas during planned or emergent outages. This results in larger area and longer-  
20 duration outage events for the Company's customers.

21

22 **Q19. What are the other challenges of the original 4.8kV distribution system?**

23 A19. Accessibility for maintenance and repairs is another major challenge of the 4.8kV  
24 system. As I noted above, in most neighborhoods, the 4.8kV system was  
25 constructed in rear lot right-of-way for aesthetic reasons since it utilized overhead



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1 poles and wires. Initially, right-of-way truck access was readily available through  
2 municipally maintained alleys in many areas, including much of Detroit. Starting  
3 in the mid-1950s, however, many municipalities began abandoning the alleys and  
4 allowing property owners to extend their fence lines, which has inhibited Company  
5 truck access to the right-of-way. This limited access continues today, resulting in  
6 extended time to locate and repair issues on the 4.8kV system, as well as increases  
7 in time to perform tree trimming and other maintenance work.

8  
9 The Company's 4.8kV system presents the following additional challenges:

- 10 • Voltage drops – The 4.8kV system can experience more significant voltage  
11 drops impacting power quality compared to higher voltage systems.
- 12 • Longer outage durations – Ringed circuit and banked secondary designs  
13 make maintenance, fault identification, troubleshooting, and restoration  
14 more difficult, and therefore, can result in longer duration outages.
- 15 • Automation challenges – The 4.8kV system is not able to fully incorporate  
16 current technology automation standards because it has a limited amount of  
17 remote monitoring and control capability when compared to higher grid  
18 voltages. Moreover, retrofitting 4.8kV substations with the equipment  
19 necessary to enhance remote monitoring and control capability is  
20 challenging given the space limitations inherent in the 4.8kV system's  
21 design and the existing, aging equipment. For example, the original 4.8kV  
22 substation design included individual relays for individual functions, usually  
23 installed on a 3-foot-by-7-foot granite panel. When a new breaker is installed  
24 these granite panels are removed and a new prewired relay panel with current  
25 technology is installed. Even though the new prewired panel reduces

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1 installation time at the substation, all the new control wires still must be  
2 installed from the panel to the breaker, which is time consuming.

3

4 **Q20. What programs did the Company design to address these challenges with the**  
5 **original 4.8kV distribution system?**

6 A20. The Company designed the 4.8kV Conversion Programs consisting of the 4.8kV  
7 Conversion Program and the 4.8kV ISO Conversion Program. Together, the 4.8kV  
8 Conversion Programs include multiple project initiatives to convert and consolidate  
9 the aged, ungrounded 4.8kV substations and their associated circuits to a grounded  
10 13.2kV configuration. The benefits of conversion include improved safety,  
11 increased capacity needed for current and future growth needs, and enhanced  
12 reliability, resiliency, and operability.

13

14 **Q21. Are any 4.8kV Conversion or 4.8kV ISO Conversion investments included in**  
15 **the Infrastructure Recovery Mechanism (IRM)?**

16 A21. Yes. The Company's 4.8kV Conversion and 4.8kV ISO Conversion investments  
17 are partitioned between recovery through base rates and the Company's authorized  
18 IRM mechanism. For the historical, bridge and test periods in the instant case,  
19 Exhibit A-12 Schedule B.5.4.8 shows the partition between the base rates requested  
20 in Exhibit A-12 Schedule B5.4 and authorized IRM amounts shown in Exhibit A-  
21 33 Schedule X1. Company Witness Willis discusses the background of the IRM  
22 and supports the inclusion of investments in the IRM. The 4.8kV Conversion and  
23 4.8 kV ISO Conversion prioritization in the IRM will follow the GPM prioritization  
24 as described by Company Witness Kryscynski, which includes using the EJ  
25 multiplier.

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1       **A. 4.8kV Conversion Program**

2       **Q22. Can you explain the 4.8kV Conversion Program?**

3       A22. As described earlier, the aged 4.8kV system has many challenges with fewer  
4       benefits for the customers that it serves in relation to the more modern 13.2kV  
5       design. In analyzing the long-term grid needs and to address the challenges of the  
6       current 4.8kV system, the Company determined that it needs a higher grid voltage,  
7       a grounded system for improved safety, and a hardened system to improve  
8       reliability & resiliency while withstanding the changing weather patterns.

9

10       The 4.8kV Conversion Program focuses on:

- 11           • Building new, modern, and higher voltage substations or, in some cases,  
12           expanding and upgrading existing 13.2kV substations to add capacity to the  
13           area/system. This allows the ability to connect new customers and supports  
14           load growth for existing and future customers;
- 15           • Completing overhead pre-conversion work, including rebuilding pole top  
16           equipment, replacing poles, wires, and transformers as needed, and installing  
17           neutral wire;
- 18           • Reconfiguring circuits and establishing new jumpering points to improve  
19           operability;
- 20           • Converting and transferring the load from the 4.8kV substations to the  
21           13.2kV substations;
- 22           • Installing controls and automation in the substations and circuits to current  
23           design standards;
- 24           • Removing arc wire and Detroit Public Light Department (PLD) primary  
25           from the Company's system, on applicable Detroit circuits; and

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- 1 • Decommissioning the aging 4.8kV substations and associated
- 2 subtransmission infrastructure.

3

4 **Q23. What are the drivers of the 4.8kV Conversion Program?**

5 A23. The 4.8kV Conversion Program is designed to resolve larger area level capacity  
6 constraints and issues. It is mainly designed to address those areas in the system  
7 where multiple substations are overloaded and adding additional capacity is the  
8 only remaining solution. As new 13.2kV sources are added to provide additional  
9 capacity relieving load constraints, the aged 4.8kV infrastructure in the area is  
10 upgraded and consolidated using the current 13.2kV construction standard. This  
11 standard implements bigger poles, modern pole-top hardware, stronger conductor,  
12 and the latest automation devices. All of these improvements result in increased  
13 capacity, reduced wire downs to improve safety, hardening, and automating of the  
14 circuits to improve reliability, resiliency, and operability for the area.

15

16 **Q24. What are the benefits of the 4.8kV Conversion Program?**

17 A24. The benefits of the 4.8kV Conversion Program are increased area capacity,  
18 enhanced safety by proactively mitigating an energized downed wire, improved  
19 reliability, resiliency, accessibility, and system maintenance efficiencies through  
20 infrastructure consolidation and decommissioning of aged equipment beyond  
21 useful life.

22

23 Added capacity

24 As I explain above, a driver of the 4.8kV Conversion Program is to provide  
25 additional capacity to relieve load constraints for an impacted area. In that regard,

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1 the program includes the conversion to a higher system voltage. As described  
2 above, adding a 13.2kV substation provides 2.75 times more capacity than building  
3 another 4.8kV source. Thus, a 13.2kV substation will add additional capacity to  
4 support new and growing customer load and better support new electrification  
5 technologies, increased EV penetration, and DERs.

6  
7 Enhanced safety

8 The higher system voltage circuit design used by the 4.8kV Conversion Program is  
9 a grounded wye 4-wire system configuration, as shown in Figure 2. Per this design,  
10 when a single wire comes down, the circuit protective devices (fuses, reclosers,  
11 breakers) trigger to isolate and de-energize the downed conductor reducing the  
12 public hazard.

13  
14 Improved Reliability & Resiliency

15 The 4.8kV Conversion Program constructs the new circuits to the current 13.2kV  
16 standard. This standard implements bigger diameter poles (class 3 or higher),  
17 modern pole-top hardware, stronger conductor (636 Aluminum (“AL”)), and the  
18 latest automation devices. These hardware upgrades along with using vertical  
19 armless construction (where feasible) hardens the circuits significantly reducing  
20 wire downs and making them more durable against falling tree branches and  
21 increasing severe weather patterns.

22  
23 The new 13.2kV design standard also implements radial circuits as compared to the  
24 aged 4.8kV ringed circuit design. The radial circuit design allows for the easier  
25 and cost-effective implementation of industry standard automation devices. With

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1 the additional implementation of the latest automation technology, the Company  
2 can better respond to outages when they occur. These modern devices in  
3 conjunction with Fault Locating, Isolation, and Service Restoration (“FLISR”)  
4 application will allow for automatic/remote operations to reduce the number of  
5 customers impacted by outages and reduce restoration time by quickly identifying  
6 trouble locations versus having the Company’s resources manually patrol circuits.  
7 This will improve reliability, resiliency, and operability of the upgraded circuits.

8  
9 Improved Circuit Accessibility

10 The 4.8kV Conversion Program also addresses the current circuit accessibility  
11 challenges. As stated before, in most neighborhoods the 4.8kV system was  
12 constructed in rear lot right-of-way municipally maintained alleys. The current  
13 accessibility issues/concerns with this approach were discussed in detail above. As  
14 new 13.2kV circuits are designed and constructed, the Company strives to relocate  
15 the main line/backbone portion of the circuit to be truck accessible. This relocation  
16 from back lot alleys to streets makes it easier to find and quickly repair trouble  
17 events on the main line/backbone of the circuit, as compared to patrolling wooded  
18 backyards on foot to identify the trouble location and then either manually climbing  
19 the poles or using specialized backyard equipment to make the repairs. Relocating  
20 the main line/backbone portion of the circuit to be road accessible reduces the time  
21 that customers experience an outage during trouble events.

22  
23 System Maintenance Efficiencies

24 The 4.8kV Conversion Program also offers several system maintenance  
25 efficiencies. A single 13.2kV substation can serve the same number of customers

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1 served by two to four older 4.8kV substations. Consolidation into a single 13.2kV  
2 substation reduces the amount of substation equipment, system cable, and overhead  
3 conductor that needs to be maintained. Converting and consolidating 4.8kV circuits  
4 and substations also allows for the decommissioning and removal of the aged 4.8kV  
5 substation equipment, and distribution and subtransmission underground cables.  
6 This will reduce the Company's emergent capital spend over time through  
7 decreased amounts of periodic and corrective maintenance as well as reactive  
8 capital. Company Witness Hill details the offset to emergent capital due to strategic  
9 capital expenditure in his direct testimony.

10

11 An example of this type of efficiency is the Company's conversion around the new  
12 13.2 kV Promenade substation. It is served directly from ITC 120kV transmission  
13 lines; this substation has 2 transformers and 12 breakers. This new higher voltage  
14 substation will support the decommissioning of three existing 4.8kV substations  
15 (Lambert, Lynch, and Pulford), all of which are more than 70 years old and beyond  
16 their expected useful life. Decommissioning these 4.8kV substations will remove  
17 at-risk equipment from the system, including 10 transformers, 14 regulators, 49 oil  
18 breakers and disconnects, more than 17 miles of 4.8kV underground cable, and  
19 more than 25 miles of 24kV subtransmission underground cable.

20

21 **Q25. What is the improvement in circuit performance following completion of a**  
22 **4.8kV Conversion Program project?**

23 A25. Notably, through the 4.8kV Conversion Program, the Company expects to see a  
24 reduction of up to 90% in customer minutes of interruption, wire downs, and trouble  
25 events based on current design standards.

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1 The most recently completed large scale conversion project in the Company's  
2 service territory was the Hilton Road Phase 1 initiative, which constructed the  
3 Hilton Road 120/13.2kV substation and converted six 4.8kV circuits from the  
4 Ferndale and Hazel Park substations to 13.2kV. Even though this initiative did not  
5 incorporate the more robust design standards used on current conversion projects  
6 (Grade B armless construction, concrete pole backbone, automatic loop schemes  
7 for all circuits, etc.) the customers in this area saw a 72% reduction in the 5-year  
8 average all weather SAIDI prior to the conversion (614 minutes average 2011-2015  
9 versus 172 minutes average 2020-2024).

10

11 **Q26. How are conversion and consolidation projects prioritized?**

12 A26. Consistent with other strategic projects and programs, conversion projects are input  
13 in the Global Prioritization Model ("GPM") for prioritization; the model is  
14 discussed by Witness Kryscynski in his direct testimony.

15

16 A conversion project's GPM score is primarily influenced by the conversion  
17 project's impacts on substation firm rating, circuit overloads, wire downs per OH  
18 mile, and substation risk plus the reliability improvement benefits and investments  
19 in Environmental Justice (EJ) communities. More detail is provided in Exhibit A-  
20 23 Schedule M8 DGP, section 9.3.4 Prioritization of Conversion Projects.

21

22 **Q27. Please describe the 4.8kV Conversion Program projects included in this case.**

23 A27. Table 2 below provides a high-level summary of the 4.8kV Conversion Program  
24 projects that are included in this case. Additional detail on each project is provided  
25 in Exhibit A-23 Schedule M6.



**Table 2 Conversion Projects**

| Table 2 – 4.8kV Conversion Projects                           |                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                       |
|---------------------------------------------------------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Project Name                                                  | Drivers                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                               |
| 4.8 kV CC: Crestwood Substation                               | Crestwood is an existing 120kV-13.2kV two transformer substation. The substation's property lease agreement is expiring. This request is to purchase the property instead of extending the lease for another 49 years. Purchasing the property would save approximately \$1,000,000 over the lease terms.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                             |
| 4.8 kV CC: Ariel Substation and Circuit Conversion            | This project will complete the conversion and transfer of load from BIHAM and DUDLY circuits to a newer Ariel Substation. Drivers for the project include the following:<br><u>Safety</u> : Minimize risk of energized downed wire<br><u>Reliability</u> : BIHAM is a one line-up switchgear substation. There is a potential of 26.8MVA of stranded load.<br><u>Operability</u> : It neighbors a smaller, heavily loaded DUDLY substation. This project is in progress to complete the conversion and transfer load of BIHAM and DUDLY circuits to new ARIEL overhead and underground circuits.<br><u>Capacity</u> : High load area with a substation already at 72%.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                |
| 4.8 kV CC: Curtis                                             | Curtis is an existing 40kV/4.8kV substation. Capacity and loading on Curtis and surrounding substations created the need for a future new substation. Drivers for the project include the following:<br><u>Capacity</u> : There is limited capacity at the substation due to gradual load growth. Curtis substation is 106% of its firm rating. Three circuits either meet or exceed the Distribution Design Order limit of 3MVA for a 4.8kV circuit. One circuit is 96% of its day-to-day rating. Two of the 40kV trunk lines are overloaded.<br><u>Reliability</u> : Reliability numbers in the area are some of the worst in our Service Territory due to aging infrastructure coupled with high tree density in the area<br><u>Operability</u> : Due to the minimal available capacity, there is great difficulty in cascading load within the general area resulting in 42% of the areas stranded after outside jumpering.<br><u>Other</u> : There is an opportunity to purchase property that will allow for the construction of a new 120-13.2kV substation that will help address the overloading issues in the Curtis area.                                                                                                                                                                                                                                                                                                                  |
| 4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) | The Promenade initiative is a conversion plan to consolidate and decommission area 24kV-4.8kV substations and convert and transfer the load to a new 120kV-13.2kV Promenade substation. Drivers for this project include the following:<br><u>Safety</u> : Significant assets are at high risk level including transformers, regulators, oil circuit breakers, disconnects, and underground cable.<br><u>Reliability</u> : Minimize risk of energized downed wire.<br><u>Capacity</u> : The Detroit Economic Growth Corporation has assembled the 186 acres I-94 Industrial Park site. 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.<br><u>Operability</u> : Future Promenade circuits will have loop schemes and jumpering points which will allow for load transfers.<br><u>Other</u> : Many pieces of major equipment have no spare parts available. |
| 4.8 kV CC: MAUME 8241 Downtown Clawson Conversion             | DC 8241 MAUME has experienced reliability issues and received numerous customer complaints resulting in townhall and customer meetings.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                               |
| 4.8 kV CC: McKinstry Sub Decommission                         | McKinstry is a 24kV/4.8kV Class C substation. As part of the Gordie Howe Bridge Project, all 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 building and remove all associated equipment.<br>Drivers for this project include the following:<br><u>Capacity</u> : There is no load on the MCKNY substation as all load has been transferred to nearby substations.<br><u>Other</u> : This project will decommission three 24kV trunk lines. It will also decommission McKinstry Substation and demolish the substation building.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                    |
| 4.8 kV CC: Power line Conversion of MADSN 175L-W              | Work is necessary to convert Madison Loop Power Line (LPL) 175 to two distinct Power Lines (PL) and remove pilot wire circuit due to cable failure. Pilot wire circuit is unjacketed, leaded cable. Numerous attempts to repair the circuit have been unsuccessful; cable continues to fail hi-potential test.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                        |

| Table 2 – 4.8kV Conversion Projects                     |                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                    |
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| Project Name                                            | Drivers                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                            |
| 4.8 kV CC: Quincy Conversion                            | <p>Quincy substation is a single transformer, single circuit 4.8kV substation. This project will construct a new 13.2kV STDF (Subtransmission Distribution Facility) and decommission the aging Quincy substation.</p> <p>Drivers for the project include the following:</p> <p><u>Safety</u>: 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.</p> <p><u>Other</u>: QUNCY transformer is constructed on railroad ties that are rotten, causing the transformer to lean, adding stress to the overhead equipment.</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                          |
| 4.8 kV CC: Cortland / Oakman / Linwood Consolidation    | <p>Linwood and Oakman substations, and their associated circuits, are significantly under loaded. To eliminate this underutilization, Linwood and Oakman substations will be decommissioned and their circuits will be consolidated into Cortland Substation. Cortland is a newer 120kV fed substation that will provide a higher level of reliability. Consolidation of these substations and subsequent removal of the associated breakers, system cable, regulators, and transformers will eliminate the need for preventive maintenance on this equipment.</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                 |
| 4.8 kV CC: GRFIN & WMSTN Conversions                    | <p>This project was initiated to provide load relief to Griffin (GRFIN) substation and associated circuits.</p> <p>Drivers for the project include the following:</p> <p><u>Safety</u>: Minimize risk of energized downed wire.</p> <p><u>Reliability</u>: GRFIN and WMSTN circuits 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.</p> <p><u>Capacity</u>: Multiple method of services (industrial customer requests) have been received in the area. Customer load creates a circuit DDO violation and substation firm violation on GRFIN before a project is executed.</p> <p>Williamston (WMSTN) substation is adjacent to GRFIN substation and is below its firm rating with capacity available. Load can be cascaded from GRFIN circuits to WMSTN circuits 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.</p> <p><u>Operability</u>: There are no jumpering options for either of the two circuits due to overloads and low voltage.</p> <p><u>Other</u>: 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.</p> |
| 4.8 kV CC: Unionville DC 301 B1 Conversion              | <p>This project will convert a section of a circuit to 13.2kV. Drivers for the project include the following:</p> <p><u>Reliability</u>: Two residential customers filed MPSC complaints in January 2023. These customers see a larger voltage flicker driven primarily by the operation of a residential on-demand water heater. However, the area has a history of motor start issues. The area is predominantly 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.</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                     |
| 4.8 kV CC: SCOTN                                        | <p>In June 2021, flooding in the Scotten (SCOTN) substation affected and condemned associated position breakers. After further investigation, it was 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.</p> <p>The drivers for this project include the following:</p> <p><u>Reliability</u>: In June 2021, flooding in the Scotten (SCOTN) substation affected and condemned associated position breakers.</p> <p><u>Other</u>: 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.</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                            |
| 4.8 kV CC: Almont Relief and Circuit Conversion (Midas) | <p><u>Safety</u>: Minimize risk of energized downed wire. Each Almont circuit is ~55 OH line miles.</p> <p><u>Reliability</u>: Almont substation was built in 1956 and there are no spare parts available for the breakers.</p> <p><u>Capacity</u>: Almont 4.8kV substation is 132% of its firm rating. ALMOT DC 304 is 93% of the day-to-day rating and ALMOT DC 303 is 87% of the day-to-day rating. 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.</p> <p><u>Operability</u>: 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 caused a breaker failure and an extensive outage for the Almont area. Due to the high loads, the substation was blocked from automatic throwover.</p>                                                                                                                                                                                                                                                                                                                                                                                                                                       |

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| Table 2 – 4.8kV Conversion Projects                                |                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                      |
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| Project Name                                                       | Drivers                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                              |
| 4.8 kV CC: Buckler Circuit Conversion                              | <p>Argo substation was built in 1926 and is a three transformer 4.8kV substation serving downtown Ann Arbor. Drivers for this project include the following:</p> <p><u>Safety</u>: Minimize risk of energized downed wire</p> <p><u>Capacity</u>: The substation is currently unable to meet capacity needs in the rapidly growing downtown Ann Arbor area. The Argo circuits are limited to 3 MVA based on the Distribution Design Order limit for a 4.8kV circuit. Argo substation was 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.</p> <p><u>Operability</u>: Increased loading on 4.8kV circuits will inhibit the ability to transfer load.</p>                                                                                                                                                                                                                                                                                                                                                                                                               |
| 4.8 kV CC: Calla Circuit Conversion and Phase 2                    | <p>Calla substation and one distribution circuit from Calla were commissioned in 2021. This project will establish a second Calla circuit to relieve load from Diamond substation and address loading and reliability concerns on a Diamond circuit and noted below. Drivers for the project include the following:</p> <p><u>Safety</u>: Minimize risk of energized downed wire</p> <p><u>Reliability</u>: 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. Project will improve reliability for over 400 customers by 93%.</p> <p><u>Capacity</u>: This circuit is at the Distribution Design Order limit of 8 MVA. DIMND Substation is 131% of firm rating. One ISO is currently loaded at 90% and is projected to be at 112% by 2026. This project will relieve ~2MVA of load from DIMND substation and adds 8 MVA of additional capacity to the area.</p> <p><u>Operability</u>: Customers at the end of this circuit are about ten miles from the substation and regularly experience low voltage/power quality issues. The project increases alternate jumpering points and capacity in the area needed to relieve load at adjacent substations.</p> |
| 4.8 kV CC: Grosse Pointe Substation and Circuit Conversion - North | <p>This project is part of the greater Grosse Pointe Area plan. Grosse Pointe North is currently served by two 4.8kV substations: Vernier (VERN) and Grosse Pointe (GRPTE). These substations combined serve approximately 16,400 customers.</p> <p>There are several drivers for this project:</p> <p><u>Safety</u>: Minimize risk of energized downed wire</p> <p><u>Reliability</u>: The average weighted cable age for the trunk lines serving these substations is 55 years. The area infrastructure is aging (70+ years weighted average age). Five year reliability data, indicates that average reliability metrics of substations in this area are worse than the DTE System average.</p> <p><u>Loading</u>: These substations are either close to or over 90% of firm (GRPTE is 85% and VERN is 99%). Eleven of the circuits out of these two substations exceed the Distribution Design Order limit of 3MVA for a 4.8kV circuit.</p> <p>The goal of this initiative is to address all the above-mentioned concerns in the Grosse Pointe Area with focus on GRPTE and VERN substations and circuit conversions.</p>                                                                                                                                                        |
| 4.8 kV CC: Melvindale                                              | <p>ALNPK, MLVDL, and ECORS are existing 4.8kV substations and JUPTR is a 13.2kV substation. Capacity and loading on these substations have created the need for a future new substation. Drivers for the project include the following:</p> <p><u>Capacity</u>: Peak loading at JUPTR substation is 104% of its firm rating.</p> <p><u>Reliability</u>: Reliability numbers in the area are some of the worst in our Service Territory due to aging infrastructure coupled with high tree density.</p> <p><u>Operability</u>: Due to the minimal available capacity, there is great difficulty in cascading load within the general area resulting in potential stranded load.</p> <p><u>Other</u>: There is an opportunity to purchase property that will allow for the construction of a new 13.2kV substation that will help address the overloading issues in the area.</p>                                                                                                                                                                                                                                                                                                                                                                                                      |
| 4.8 kV CC: Pinegrove Substation Relocation and Conversion          | <p>This project is driven by MDOT needing the substation to be moved. Secondary driver include substation risk and reliability.</p> <p>The Bluewater Bridge is being expanded and Pinegrove substation needs to be removed to accommodate the expansion. New Neon substation will need two 40 KV feeds</p> <p>Pinegrove substation interferes with MDOT's expansion plans. Pinegrove substation is also a 100-year-old sub and is not a standard configuration. Pine Grove has no circuit switcher on high side of the transformer, instead it has high speed ground switches. This relocation work will decommission the current sub and build a new substation to current standards out of the way of MDOT's expansion plans.</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                  |

| Table 2 – 4.8kV Conversion Projects                     |                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                       |
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| Project Name                                            | Drivers                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                               |
| 4.8 kV CC: Zenon Substation and Circuit Conversion      | <p>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 &amp; 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 flooding events in the Scotten substation area in 2021, low reliability, and load increases driven by West Riverfront and Corktown development, the second phase of Zenon Conversions is to be initiated.</p> <p><u>Reliability:</u> Recent flooding events in the Scotten substation area and low reliability</p> <p><u>Capacity:</u> Load increases driven by West Riverfront and Corktown developments.</p> <p><u>Operability:</u> Completing this work will decommission WSEND and SCOTN substation along with their associated 24kV trunk lines.</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                               |
| 4.8 kV CC: Rochester Decommissioning and Tienken Relief | <p>Rochester Substation is a 4.8kV substation that was built in 1921 in downtown Rochester Hills that serves 16 overhead miles to the downtown Rochester area. Rochester substation is surrounded by substations that are over firm with no available capacity. It is necessary to build a new substation to serve the downtown Rochester area and provide load relief to Tienken substation. Drivers for the project include the following:</p> <p><u>Safety:</u> Minimize risk of energized downed wire.</p> <p><u>Capacity:</u></p> <ul style="list-style-type: none"> <li>• Rochester Substation is surrounded by Tienken, Spokane, Seneca and Disco Substations.</li> <li>• Tienken Substation is at 97% of its firm rating (based on 2024 loading) with one available spare position.</li> <li>• Spokane Substation is at 114% of its firm rating (based on 2024 loading) with no spare position.</li> <li>• Seneca Substation is at 118% of its firm rating (based on 2024 loading) with no spare position.</li> <li>• The neighboring substations lack the ability for expansion due to physical constraints or being overloaded and hence cannot provide load relief to Rochester.</li> </ul> <p><u>Reliability:</u></p> <ul style="list-style-type: none"> <li>• DC 1838 ROCHR averaged 13 wire downs in the past 5 years.</li> <li>• DC 1823 ROCHR averaged 7 wire downs in the past 5 years.</li> <li>• DC 1814 ROCHR averaged 6 wire downs in the past 5 years.</li> </ul> <p><u>Operability:</u> Rochester Substation is a 4.8kV island surrounded by 13.2kV substations/circuits.</p> <p><u>Other:</u> The substation is surrounded by retail shops making any equipment failure/replacement a physical challenge.</p> |
| 4.8 kV CC: New Baltimore                                | <p><u>Capacity:</u> NBALT 40/13.2kV CLASS R Substation is at 140% of its FIRM (19.5 MVA Loading, 13.9 MVA FIRM) with two circuits over DDO limit (8 MVA). Circuit 1 loading is currently at 8.9 MVA (68% D-D, 13.1 MVA Normal). Circuit 2 loading is currently at 11.2 MVA (86% D-D, 13.1 MVA Normal)</p> <p><u>Operability:</u> There is no option to use overhead jumpering for NBALT 4.8kV load due to circuits being surrounded by 13.2kV substations. NBALT Class R 140% of Firm with 93 blocking hours on the year and potential in resulting in stranded load in case of TRK 4911 outage</p> <p><u>Safety:</u> Minimize risk of energized downed wire</p> <p><u>Reliability:</u> There are existing low voltage issues on the NBALT 13.2kV load due to overloaded circuits. NBALT 13.2kV has equipment related outages. NBALT 13.2kV circuits have several instances in last 5 years being 4th quartile in SAIDI, SAIFI, CAIDI</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                             |
| 4.8 kV CC: Belleville Substation and Circuit Conversion | <p>Belleville Substation has a 13.2kV side with one circuit and a 4.8kV side with 3 load carrying circuits and a throwover circuit. There is a separate project to decommission the 4.8kV switchgear and reconfigure the circuits into two load carrying circuits. Once that work is complete, work can begin for this project to decommission the 4.8kV side of Belleville substation and expand the 13.2kV side of the substation. Drivers for this project include the following:</p> <p><u>Safety:</u> 4.8kV system hazards</p> <p><u>Capacity:</u> Belleville Substation is at 102% of firm and the 13.2kV side of Belleville Substation is at 91% of its firm. The single circuit at the 13.2kV side of the substation exceeds the Distribution Design Order limit of 8MVA for a 13.2kV circuit</p> <p><u>Operability:</u> The 4.8kV side of BELVL Substation is an island and relies on internal jumpering for outages. The surrounding circuits operate at 13.2kV or have 4.8kV ISO-pockets which do not have the ability to carry large sections of the Belleville 4.8kV circuits</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                        |
| 4.8 kV CC: Camden Decommissioning                       | <p>Transformer # 1 Primary is arcing. Outstanding repairs affects Trunk 1276 serving IVNHO, CAMDN 13.2kV, WRNSI, NIXON substations. Frequent, momentary interruptions and 4.8kV ground alarms</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                     |

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| Table 2 – 4.8kV Conversion Projects                          |                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                    |
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| 4.8 kV CC: Unionville Decommissioning and Circuit Conversion | <p>This project will construct a new 13.2kV substation and decommission the aging 4.8kV Unionville substation. Drivers for the project include the following:</p> <p><u>Safety</u>: Minimize risk of energized downed wire</p> <p><u>Reliability</u>: Aging substation equipment increases risk of failure</p> <p><u>Capacity</u>: Unionville substation is a 4.8kV distribution substation with two load carrying circuits. The substation is 95% of its firm rating. Unionville substation is equipped with three single phase 500kV transformers and they are the limiting element at the substation.</p> <p><u>Operability</u>: Limited jumpering capabilities.</p> <p><u>Other</u>: There have been seven Method of Service requests in the Unionville area but the requests did not move forward due to the substantial upgrade costs which has led to repeated escalation and MPSC complaints.</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                          |
| 4.8 kV CC: Ann Arbor AC Network Conversion                   | <p>This project will replace AC Network pedestals and netbank transformers. It will also upgrade Hoover Substation from 40-4.8kV to 40-13.2kV substation, by converting Hoover circuits and transferring them to adjacent State Substation and rebuilding Hoover Substation to 13.2kV. Drivers for the project include the following:</p> <p><u>Safety</u>: Conversion to 13.2kV will minimize risk of energized downed wire.</p> <p><u>Reliability</u>: All primary distribution cables run within the same conduit. If there is a major failure within the conduit then multiple customers will be out of power for an extended period of time.</p> <p><u>Capacity</u>: The AC network system consists of network feeders, network transformer bank assemblies and network secondary conductors. The system is designed to eliminate service interruptions due to the failure of a primary feed. DTE is developing plans to convert the Ann Arbor AC network from 4.8kV to 13.2kV. The City of Ann Arbor has issued an ordinance geared towards increasing use of electric vehicles which would increase demand in Ann Arbor and has a goal to be carbon neutral by 2030. The existing electrical infrastructure is not able to accommodate this expected load growth.</p> <p><u>Operability</u>: Netbank column inspections have been conducted in 2019 and have found many in need of repair. In order to convert the AC Network, all columns will need to be replaced because the existing columns/foundations are not able to support the larger dual transformer units being installed.</p> |
| 4.8 kV CC: Grosse Pointe Substation and Circuit Conversion   | <p>This project is part of the greater The Grosse Pointe Area plan. Grosse Pointe is currently served by four 4.8kV substations: Denver (DENVR), Wayburn (WAYBN), Vernier (VERN) and Grosse Pointe (GRPTE). These substations combined serve approximately 30,000 customers.</p> <p>There are several drivers for this project:</p> <p><u>Safety</u>: Minimize risk of energized downed wire</p> <p><u>Reliability</u>: The average weighted cable age for the trunk lines serving these substations is 55 years. The area infrastructure is aging (70+ years weighted average age). Five year reliability data, indicates that average reliability metrics of substations in this area are worse than the DTE System average.</p> <p><u>Loading</u>: Three of the four substations exceed 90% of firm (DENVR is 115%, WAYBN is 96% and VERN is 99%). Twenty of the circuits out of these four substations exceed the Distribution Design Order limit of 3MVA for a 4.8kV circuit.</p> <p>This project will allow us to focus on DENVR and WAYBN's conversions.</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                |
| 4.8 kV CC: Hemlock Decommissioning and Circuit Conversion    | <p>Hemlock (HEMLK) is a 4.8kV substation that is at 99% 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. This project will help relieve existing overload conditions at this substation and provide additional capacity for existing and new customer load. Drivers for the project include the following:</p> <p><u>Safety</u>: Minimize risk of energized downed wire</p> <p><u>Reliability</u>: SAIFI 5-year average is 1.00 and SAIDI 5-year average is 485.</p> <p><u>Capacity</u>: One circuit exceeds the Distribution Design Order limit of 3MVA for a 4.8kV circuit. Hemlock (HEMLK) is a 4.8kV substation that is at 99% of its firm rating. The Ann Arbor area has a 44% projected 15-year load growth in the area.</p> <p><u>Operability</u>: Hemlock area is adjacent to both 13.2kV and 4.8kV substation areas which limits the jumpering capabilities for emergency restoration.</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                       |

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| Table 2 – 4.8kV Conversion Projects                          |                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                  |
|--------------------------------------------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Project Name                                                 | Drivers                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                          |
| 4.8 kV CC: White Lake Decommissioning and Circuit Conversion | <p>This project entails building a new 40kV - 13.2kV substation to support WHTLK (4.8kV) preconversion and conversion and to also provide load relief to WHTLK and neighboring substations. Drivers for the project include the following:</p> <p><u>Safety:</u> Minimize risk of energized downed wire</p> <p><u>Reliability:</u> WHTLK(13.2kV) and WHTLK(4.8kV) have fluctuated with the DTE system average throughout the past 5 years. In 2023 the SAIDI for WHTLK(13.2kV) and WHTLK(4.8kV) was greater than the DTE system average. WHTLK (13.2kV) has also fluctuated with the DTE system average for CAIDI throughout the past 5 years. WHTLK(13.2kV) was near the DTE system average for CAIDI in 2023.</p> <p><u>Capacity:</u> According to the 2024 ALA, WHTLK(13.2kV) is at 81% of its FIRM. WHTLK(4.8kV) is at 97% of its FIRM. White Lake Township is expecting new light industry buildings and a new substation will help support WHTLK substation and neighboring substations.</p> <p><u>Operability:</u> Unable to move load off WHTLK due to neighboring substations being overloaded. WHTLK substations is surrounded by four other substations. 3 of the five substations are currently over 90% of their FIRM ratings and one is approaching 90% of its FIRM. There are no possible jumpering available to use on WHTLK(4.8kV) in case of an emergency.</p> <p><u>Other:</u> The existing substation site is too small to support replacing major equipment. Once the NEW MDWLK substation is built we would be able to bring CLYDE and WDLOW below FIRM. This substation has the potential to benefit every substation surrounding it.</p> |
| 4.8 kV CC: Barber Substation and Circuit Conversion          | <p><u>Safety:</u> Minimize risk of energized downed wire</p> <p><u>Reliability:</u> BUNRT 4.8 and MELRO have a 5-year SAIDI average in 4th quartile. BUNRT 13.2kV and ROSVL have a 5-year SAIDI average in 4th quartile.</p> <p><u>Capacity:</u> ROSVL substation has 15 circuits and is at 86% of Firm. 2 ROSVL circuits are at or exceed the DDO limit of 3MVA. MELRO substation has 9 circuits and is at 99% of Firm. 4 MELRO circuits exceed the DDO limit of 3MVA. 2 MELRO circuit are at or exceeding their DD rating. BUNRT 13.2kV substation has 6 circuits and is at 98% of Firm. 2 BUNRT circuits are at or exceed the DDO limit of 8MVA. 24kV sub-transmission lines feeding ROSVL, MELRO, and BUNRT exceed their emergency ratings.</p> <p><u>Operability:</u> Out of the 13 ROSVL circuits, only 2 have jumpering outside of the T.O. circuit. Out of the 9 MELRO circuits, only 3 have jumpering outside of the T.O. circuit.</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                  |
| 4.8 kV CC: Birmingham Decommissioning and Circuit Conversion | <p><u>Safety:</u> Minimize risk of energized downed wire</p> <p><u>Reliability:</u> BIHAM is a one line-up switchgear (single point of failure) substation. Project addresses aging infrastructure, and high substation outage risk. In addition, nearby Quarton Road substation has 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 frequent interruptions.</p> <p><u>Operability:</u> Birmingham substation serves crowded, traffic dense downtown Birmingham and surrounding areas. Deployment of mobile fleet will entail road traffic shutdown until Emergency repairs are completed.</p> <p><u>Capacity:</u> The substation present and committed loads are near substation firm rating. Future customer load increase will place the substation over its firm rating, in violation of DTE Electric's Distribution Design Standards.</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                  |
| 4.8 kV CC: Hawthorne Relief and Circuit Conversion           | <p>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. This initiative includes converting areas from 4.8kV to 13.2kV, load transfers, construction of new substations and substation expansions. Key drivers for the need for system upgrade include the following:</p> <p><u>Safety:</u> Minimize risk of energized downed wire</p> <p><u>Reliability:</u> 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). Some equipment at these substations (breakers, cables, etc.) is at an elevated risk for failure.</p> <p><u>Capacity:</u> Three of the substations in the area exceed their firm ratings: HAWTH (128%), VILLA (110%) and DALY (106%). Several circuits on these five substations exceed the Distribution Design Order limit of 3MVA for a 4.8kV circuits. Five circuits exceed their day-to-day rating. There is limited load capacity to accommodate projected load growth in the area</p> <p><u>Operability:</u> There are limited jumpering opportunities due to geography coupled with heavily loaded nearby circuits resulting in stranded load.</p>                                                                                                                                                                                                                                                                                                                                                          |



| Table 2 – 4.8kV Conversion Projects                           |                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                       |
|---------------------------------------------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Project Name                                                  | Drivers                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                               |
| 4.8 kV CC: Hilton Substation and Circuit Conversion           | <p>The Hilton Road (HLTRD) Substation and Circuit Conversion is intended to align strategies between serving new load and addressing aging infrastructure. The HLTRD project will increase operability, capacity, and reliability for commercial and residential customers in the Ferndale, Hazel Park, Pleasant Ridge, Royal Oak Charter Township, and Oak Park area. There are several drivers for this project including:</p> <p><u>Safety:</u> Minimize risk of energized downed wire</p> <p><u>Reliability:</u> The 5-Year SAIDI of the 4.8kV in the project area is approximately 4.6 times the standard for the system.</p> <p><u>Capacity:</u> The 4.8kV in the project area has about 43.9MVA of load that is covered by (21) load-carrying circuits. The circuits are limited to 3MVA DDO.</p> <p><u>Operability:</u> The current configuration has potential for stranded load and long restoration times for customers in the event of an outage.</p> <p><u>Other:</u> This project will decommission four 24kV trunk lines at LINCEN (Lincoln) station with average weighted cable age of ~55 years.</p> |
| 4.8 kV CC: BRITN                                              | <p><u>Safety:</u> Minimize risk of energized downed wire.</p> <p><u>Reliability:</u> The breaker at BRITN substation on position J failed, which is for TRF2. BRITN is a 4.8kV Island with no jumpering outside the substation. In other words, if there is a failure at TRF1, BRITN substation's load will be stranded.</p> <p><u>Capacity:</u> Capacity concern is when both substation transformers/busses fail at the same time due to no outside jumpering because BRITN is a 4.8kV Island substation. Substation is at 72% FIRM</p> <p><u>Operability:</u> BRITN is a 4.8kV island with no jumpering points to other substations' circuits. Therefore, DGs will not work for a contingency plan.</p> <p><u>Other:</u> There are concerns that the other breakers at the substation may fail due to the type and age.</p>                                                                                                                                                                                                                                                                                        |
| 4.8 kV CC: Pittsfield Substation and Circuit Conversion       | <p>This project involves constructing a new 13.2kV substation and decommissioning an aging 4.8kV substation. Drivers for the project include the following:</p> <p><u>Safety:</u> Minimize risk of energized downed wire</p> <p><u>Reliability:</u> Pittsfield circuits have an average 5-year AW SAIDI of 858 and a 5-year AW CAIDI of 565.</p> <p><u>Capacity:</u> Two circuits exceed the Distribution Design Order limit of 3MVA for a 4.8kV circuit. 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 an 18% projected 15-year load growth in the area. Adjacent substations (Crown and Wolverine) are over their substation firm ratings.</p> <p><u>Operability:</u> Pittsfield area is adjacent to both 13.2kV and 4.8kV substation areas which limits the jumpering capabilities for emergency restoration.</p>                                                                                                                                                                    |
| 4.8 kV CC: Yale-Slater Decommissioning and Circuit Conversion | <p><u>Safety:</u> Minimize risk of energized downed wire. According to EPPM scores: relays and transformers at YALE are at high or severe risk.</p> <p><u>Reliability:</u> YALE DC2615 has 5-year SAIDI averages in 4th quartile. YALE DC2633 has a 5-year SAIDI average in 2nd quartile. The initiative area has a 5-year SAIDI average in 3rd quartile.</p> <p><u>Capacity:</u> YALE substation has 4 circuits and is at 5.2MVA with a Firm of 3.7MVA (141%). DC2615 exceeds the emergency rating of the T.O. circuit. DC2633 is 0.3MVA from exceeding the emergency rating of the T.O. circuit. There is -0.5MVA of capacity remaining over 43 square miles of DTE service territory.</p> <p><u>Operability:</u> One YALE circuit lacks any jumpering capabilities. YALE has no external jumpering points.</p>                                                                                                                                                                                                                                                                                                     |

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1 **Q28. What did the DTE Electric Utility Distribution Audit Report from Liberty**  
2 **Consulting in Case No. U-21305<sup>6</sup> (the “Audit Report”) recommend regarding**  
3 **the Company’s 4.8kV Conversion Program?**

4 A28. At the outset, the Audit Report recognized that the 4.8kV circuits were aging and  
5 that there were other concerns.<sup>7</sup> Additionally, the Audit Report noted that the  
6 Company needs to add capacity to support current and future growth.<sup>8</sup>

7  
8 Specific to the 4.8kV Conversion Program, while recognizing that the Company’s  
9 “planning for 4.8kV conversions limits them to cases where those capacity limits  
10 apply” is “sound,” the Audit Report recommended that the Company “limit 4.8kV  
11 conversions to those necessary for substantial capacity reasons.”<sup>9</sup>

12  
13 **Q29. Do the Company’s 4.8kV Conversion Program projects included in the instant**  
14 **case address capacity as recommended in the Audit Report?**

15 A29. Yes, the above-listed 4.8kV Conversion Program projects are all capacity related;  
16 I further discuss that the capacity constraint resolutions of these projects is at the  
17 system level in my next Q&A. The Company notes, however, that it is important to  
18 consider the other factors of safety, reliability and system operability when

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<sup>6</sup> The DTE Electric Audit Reports are available in filing ## U-21305-0012 and U21305-0013 at <https://mi-psc.my.site.com/s/case/5008y000005KkdgAAC/in-the-matter-on-the-commissions-ownmotion-to-investigate-audit-and-review-the-methods-employed-by-dte-electric-company-and-consumers-energycompany-to-secure-good-electric-service-and-the-safety-of-the-public-pursuant-to-mcl-460555-and-mcl-460556> (accessed April 7, 2025)

<sup>7</sup> See, e.g., Audit Report, Part 1 at 8 (“DTE has been using 4.8kV delta circuits since the early 1900s, with some configured as looped circuits and others as radial. Beyond condition-related concerns, these ungrounded delta circuits pose a safety risk.”).

<sup>8</sup> Audit Report, Part 2 at 78 (“The one-third of DTE’s distribution system built before 1965 faces limitations in providing the expected capacity that growing electric vehicle and home heat pumps and appliance use are expected to bring, along with growth experienced and expected in some locations in the Company’s service territory. DTE plans significant investments for converting portions of the 4.8kV ungrounded system to the modern, 13.2kV grounded system to improve safety and reliability, as well as providing additional capacity.”); Audit Report, Part 2 at 85 (stating that “DTE’s planning for 4.8kV conversion limits them to cases where capacity limits apply, which is sound.”).

<sup>9</sup> Audit Report, Part 2 at 85.



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1 determining priority and the execution timing of these projects. Per the Audit  
2 Report recommendation, the Company will continue to plan and execute all  
3 proposed 4.8kV conversion projects for the next 5 years since all are driven by  
4 capacity needs. Conversion projects outside of the current 5-year window, or those  
5 not part of projects presented in the instant case, will be proposed if needs are driven  
6 by supporting benefit-cost analysis, including capacity needs.

7

8 **Q30. Can you further detail how the Company's 4.8kV Conversion Program**  
9 **projects address system-level capacity constraints?**

10 A30. Yes. As I detailed earlier in my testimony, capacity constraints negatively impact  
11 the grid's ability to be resilient (limited redundancy), respond to major events,  
12 directly impact the Company's ability to serve new customer loads, and affects the  
13 Company's ability to realize the full benefit of the automation technology inherent  
14 with DERs. These operational, reliability, and customer impacts, particularly at the  
15 system level, can require a long lead-time to resolve.

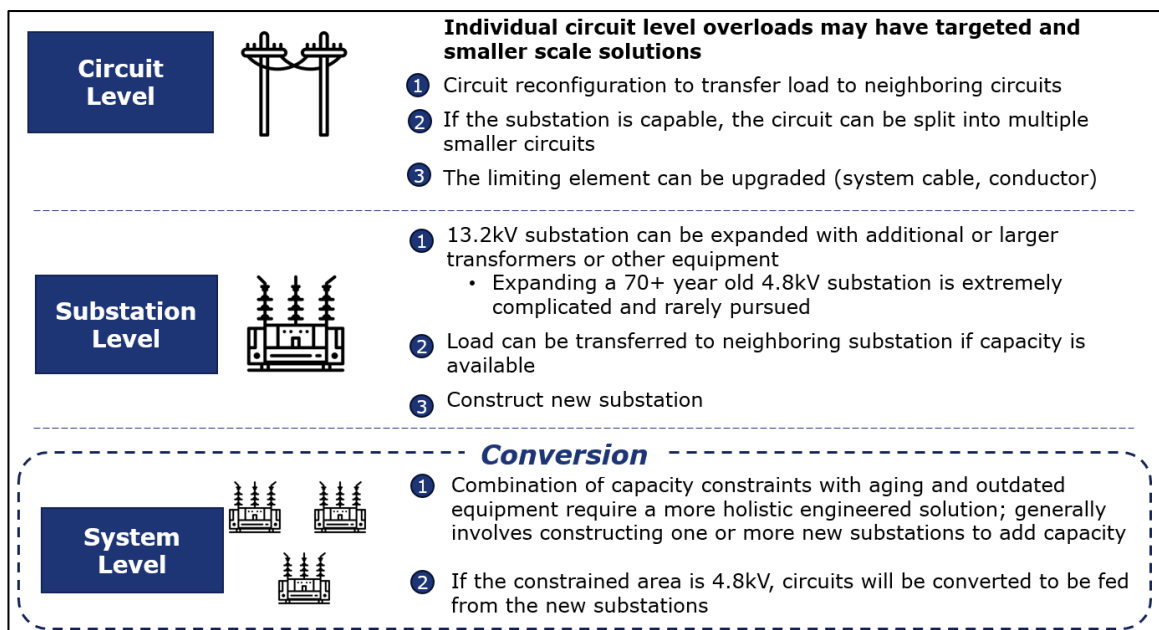
16

17 Capacity constraints and their associated solutions vary depending on the scope and  
18 location of where these capacity constraints are taking place and there is no one-  
19 size-fits-all solution. There are generally three levels of overloading conditions that  
20 could occur across the grid – at the circuit level, at the substation level, and at the  
21 system level – as shown in Figure 6 below. In the context of the Company's 4.8kV  
22 Conversion Program, capacity constraints are addressed at the system level. In other  
23 words, an individual circuit or an individual substation does not need to have a  
24 capacity constraint (i.e. be overloaded) before conversion is the appropriate  
25 solution.

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For example, the Hawthorne 4.8kV Conversion, which I discuss further in a later Q&A, addresses the Dearborn Heights area where four of the five substations in the initiative area are overloaded, meaning there is not additional capacity to accommodate the area's projected load growth. Additionally, outages in the area can result in extended outages due to circuit topology and lack of capacity. The Hawthorne Conversion addresses significant load constraints at the system level, although not every substation nor every circuit in the area is experiencing a load constraint.

**Figure 6 Levels of Overloading Conditions**



**Q31. Are there additional benefits other than capacity provided by the 4.8kV Conversion Program projects?**

**A31.** Yes, there are. In addition to increased capacity, benefits of the 4.8kV Conversion Program include enhanced safety by proactively mitigating an energized downed wire, improved reliability, resiliency, accessibility, and system maintenance

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1 efficiencies through infrastructure consolidation and decommissioning of aged  
2 equipment beyond useful life. For additional details about these benefits, please see  
3 Q24 above.

4

5 **Q32. Are there specific 4.8kV Conversion Program projects that you would like to**  
6 **discuss in more detail?**

7 A32. Yes. I would like to highlight two conversion project examples that will help  
8 explain the scope, rationale, and benefits of the Company's 4.8kV Conversion  
9 Program. The example projects are:

- 10 • 4.8kV CC: I-94 Substation and Circuit Conversion (Promenade); and
- 11 • 4.8kV CC: Hawthorne Relief and Circuit Conversion

12

13 **Q33. What are the drivers of the 4.8kV CC: I-94 Substation and Circuit Conversion**  
14 **(Promenade) project, which is also referred to as "Promenade Conversion"?**

15 A33. The Detroit I-94 industrial park has plans to add new commercial and industrial  
16 customers to this area. This will result in increased loads that the current 4.8kV  
17 system will not be able to adequately support. The area is currently fed by Lynch,  
18 Lambert, and Pulford 4.8kV substations, all of which are over 80 years old. The  
19 Promenade Conversion will reduce DTE Electric infrastructure in the area by  
20 decommissioning the three existing 4.8kV substations, reducing equipment failure  
21 risk and simplifying trouble identification.

22

23 The Promenade Conversion will also provide relief to the increased capacity  
24 demand that came from the Public Lighting of Detroit (PLD) conversions when that  
25 load transferred over to the DTE Electric system. The impact of this load is

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1 resulting in overloads in some areas which have created planning criteria violations  
2 with detrimental impact to operational flexibility and service reliability.

3

4 Also, the Promenade Conversion addresses existing ITC transmission system  
5 loading violations. Currently, the ITC transmission system feeding the east  
6 downtown area has several Midcontinent Independent System Operator (“MISO”)  
7 loading violations which require mitigation. Engineers from ITC and DTE Electric  
8 collaborated to develop a set of projects to resolve the transmission system  
9 violations, with the Promenade Conversion being one of these projects, resulting in  
10 a \$130 million reduction in cost to customers over the original proposed ITC  
11 solution.

12

13 **Q34. What is the scope of the Promenade Conversion?**

14 A34. The Promenade Conversion is located on the eastside of Detroit and involves  
15 construction of the new 120kV to 13.2kV Promenade substation and the conversion  
16 and transfer of 4.8kV circuits out of the Lambert, Lynch, and Pulford substations  
17 to the new Promenade substation. In total 23 circuits (8 Lambert, 5 Lynch, and 10  
18 Pulford circuits), comprising approximately 100 miles of 4.8kV circuits, will be  
19 modernized and converted to six 13.2kV circuits. Consolidating and transferring  
20 the 23 circuits to Promenade will support the decommissioning of Lambert, Lynch,  
21 and Pulford substations later in the Promenade Conversion. Additionally, the new  
22 120kV transmission feed will allow for the decommissioning of four 24kV trunk  
23 lines with a weighted average age (“WAA”) of 90 years.<sup>10</sup>

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<sup>10</sup> Weighted Average Age - The ages of the cables weighted by length.

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1   **Q35. What are the benefits of the Promenade Conversion?**

2   A35. The Promenade Conversion eliminates existing ITC transmission system violations  
3       and provides 30% additional substation distribution capacity to serve residential,  
4       commercial, and industrial customers in the city of Detroit and in the area southwest  
5       of Detroit City Airport. The new 13.2kV Promenade substation served directly from  
6       ITC 120kV transmission lines has two transformers and 12 breakers and will  
7       support the decommissioning of existing 4.8kV substations Lambert, Lynch, and  
8       Pulford; all of which have surpassed the practical service life and are beyond 80  
9       years old. Decommissioning these substations will remove at risk equipment,  
10      including 10 transformers, 14 regulators, 49 oil circuit breakers and disconnects,  
11      more than 17 miles of 4.8kV underground cable, and more than 25 miles of 24kV  
12      underground cable. In addition to capacity, conversion of the circuits will improve  
13      safety, reliability, operability and maintenance for the customers in this area as well  
14      as DTE Electric, with a projected 75-80% reduction in SAIDI and removal of all  
15      PLD primary and arc wire in this area.

16

17   **Q36. Turning to the 4.8 kV CC: Hawthorne Relief and Circuit Conversion**  
18       **(“Hawthorn Conversion”), what are the drivers of that project?**

19   A36. The Hawthorne Conversion was created to address overloads in the Dearborn  
20       Heights area affecting multiple 4.8kV substations in proximity to one another  
21       (Hawthorne 141%, Villa 110%, Daly 103%, Biltmore 90%, and Glendale 75% of  
22       Firm Rating). The net capacity of these substations is 4 MVA over the total load  
23       carrying capacity with a projected load growth of approximately 19 MVA by 2035,  
24       which cannot be supported with the existing infrastructure. Twenty-three of the  
25       4.8kV circuits in scope are over the Company’s Distribution Design Order

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1 (“DDO”) limit of 3.0 MVA. The heavy loading combined with geographic  
2 limitations in the area due to the circuit’s location within the Rouge River watershed  
3 area creates severe operating constraints and stranded load in emergency situations  
4 which limits the installation of automatic restoration schemes. In addition to  
5 capacity drivers, the initiative area also experiences three times more annual wire  
6 downs than the DTE Electric system average. All the substations in the area were  
7 commissioned between 1947 and 1961.

8

9 **Q37. What is the scope of the Hawthorne Conversion?**

10 A37. The scope of this conversion includes:

- 11 • Build two new 13.2kV substations and expand the existing Mallard 13.2kV  
12 substation to address the existing overloads and projected future load growth in the  
13 area.
- 14 • Replace aging 4.8kV infrastructure with more robust 13.2kV infrastructure to  
15 improve reliability through conversion of approximately 279 miles of overhead  
16 circuits from Hawthorne, Daly, Glendale, and Villa substations and transfer them  
17 to Mallard and the two newly constructed substations.
- 18 • Decommission Hawthorne, Daly, Glendale, and Villa 4.8kV substations and  
19 infrastructure.

20

21 **Q38. What are the benefits of the Hawthorne Conversion?**

22 A38. The Hawthorne Conversion will eliminate overloaded infrastructure in the area and  
23 increase available capacity for future load growth and electrification. The existing  
24 aging 4.8kV infrastructure at four substations (Hawthorne, Daly, Glendale, and  
25 Villa) will be decommissioned and consolidated into two new 120kV/13.2kV

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1 substations and the expanded Mallard 120kV/13.2kV substation. The area will see  
2 increased reliability and reduced wire downs from the re-configuration, rebuilding,  
3 protection and automation installed during the circuit conversion.

4

5 **Q39. Can you further explain why the Promenade and Hawthorne Conversions are**  
6 **illustrative examples of the 4.8kV Conversion Program as a whole?**

7 A39. Yes. As I detailed earlier in my testimony, the Company's 4.8kV Conversion  
8 Program addresses capacity constraints at a system level. The Promenade and  
9 Hawthorne Conversions resolve system area conditions by adding a 13.2kV source  
10 to alleviate system loading issues and capacity constraints. By using enhanced  
11 construction standards, these conversions harden the system, improve reliability,  
12 and provide enhanced safety.

13

14 **B. 4.8kV ISO Conversion Program**

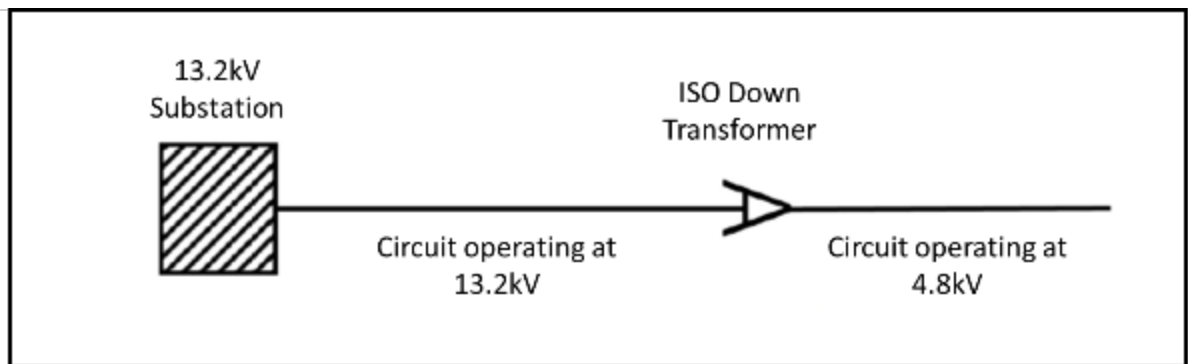
15 **Q40. How does the 4.8kV ISO Conversion Program relate to the 4.8kV Conversion**  
16 **Program?**

17 A40. In some areas, the Company operates portions of circuits at 4.8kV that are fed from  
18 a 13.2kV substation, using a transformer to reduce the higher substation voltage to  
19 the lower circuit voltage. These types of circuits are referred to as "isolation down"  
20 or "ISO down" circuits. This grid configuration exists where in the past there was  
21 a need to address immediate overloading on circuits fed from a substation at which  
22 other circuits were not overloaded. To address the circuit overload situation, the  
23 Company constructed a higher voltage, 13.2kV substation, and converted only the  
24 overloaded circuits, or portions of the circuits, to the higher voltage. In this  
25 scenario, the remaining non-overloaded circuits are operated at the existing voltage,

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1 typically 4.8kV. The portions of circuits that were not modernized and converted  
2 to 13.2kV included installation of an isolation down transformer and continued to  
3 be served at 4.8kV. Figure 7 illustrates a 13.2kV circuit utilizing an ISO down  
4 transformer.

5  
6 **Figure 7 “ISO” Down Example**



7 To address the circuits with ISO downs, the Company developed the 4.8kV ISO  
8 Conversion Program.

9  
10 **Q41. What are the drivers behind the 4.8kV ISO Conversion Program?**

11 A41. The Company began to install 13.2kV infrastructure to replace the 4.8kV  
12 distribution system in the 1970s, in large part driven by the rapid load growth from  
13 residential air-conditioning. Since that time, ISO-down installations have been a  
14 cost-effective and efficient, temporary approach to address loading concerns at  
15 source substations without full conversion of the downstream circuits that required  
16 significantly more time and investment. As these were designed as temporary  
17 measures, the Company intended to implement a program to rebuild and modernize  
18 these circuits as part of a larger modernization and rebuild program. Therefore,  
19 similar to circuit conversions that are part of the 4.8kV Conversion Program, the



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1 4.8kV ISO Conversion Program is designed for rebuilding and modernizing the  
2 4.8kV portions of circuits to a higher voltage.

3  
4 More specifically, the 4.8kV ISO downed areas of the circuits have not been  
5 upgraded or modernized, and therefore, have the same characteristics of  
6 ungrounded 4.8kV circuits fed from 4.8kV substations. Because these areas are  
7 ungrounded, a downed wire may stay energized, thereby presenting the same  
8 reliability, operational, and safety mitigation challenges as other 4.8kV circuits.  
9 ISO downed areas of the circuits also face the same capacity challenges when it  
10 comes to incorporating load, including increasing EVs and DERs. Capacity within  
11 an ISO area can be limited both by the size of the ISO transformers themselves or  
12 the wire size, which is often smaller than current design standards.

13

14 **Q42. Can you explain the scope of the 4.8kV ISO Conversion Program?**

15 A42. The scope of work for the 4.8kV ISO Conversion Program includes:

- 16 • Completing overhead pre-conversion work, including rebuilding pole tops,  
17 replacing poles and transformers as needed, and installing neutral wire;  
18 • Rebuilding underground infrastructure as needed;  
19 • Reconductoring overhead wires as needed based on new circuit  
20 configurations and existing wire size;  
21 • Reconfiguring circuits and establishing new jumpering points;  
22 • Installing controls and automation in the substations and circuits to our latest  
23 design standards;  
24 • Removing ISO down transformers.

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This scope of work is consistent with the scope of work for the 4.8kV ISO Conversions Program that the Commission found “reasonably supported” in terms of capital expenditures requested in the Company’s last electric rate case.<sup>11</sup> As noted above, the capital expenditures in the instant case, shown on Exhibit A-12, Schedule B5.4, page 13, line 83, are a continuation of the capital expenditures presented in Case No. U-21534.

**Q43. What portion of the system is served by ISO down areas?**

A43. Table 3 below provides the number of circuits with ISO downs, number of customers served, and the 4.8kV overhead and underground line miles on the Company’s system. The 5,804 miles of overhead within ISO down areas represents approximately 1/3 of the Company’s 4.8kV system.

**Table 3 Number of Circuits with ISO Downs**

|                            | Number of<br>Circuits | Number Of<br>Customers | Miles Overhead<br>Circuit | Miles<br>Underground<br>Circuit |
|----------------------------|-----------------------|------------------------|---------------------------|---------------------------------|
| <b>4.8kV ISO<br/>Downs</b> | 430                   | 145,028                | 5,804                     | 438                             |

**Q44. What are the benefits of the 4.8kV ISO Conversion program?**

A44. The benefits of the 4.8kV ISO Conversion program are similar to the benefits of the 4.8kV Conversion Program, including providing additional capacity, improving reliability with equipment and technology modernization, and improving safety. Like a full conversion and consolidation project, 4.8kV ISO conversions are expected to deliver up to 90% reliability improvements within the areas impacted, as described in detail starting on page RMS-23.

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<sup>11</sup> Case No. U-21534 - Commission Order, January 23, 2025, p. 128.

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1   **Q45. How are circuits in the 4.8kV ISO Conversion program prioritized?**

2   A45. First, as Company Witness Kryscynski explains in his testimony, the 4.8kV ISO  
3       Conversion Program is ranked in the investment portfolio as a whole using the  
4       Global Prioritization Model (“GPM”). For ISO circuits, the GPM considers  
5       capacity including actual loading of the ISO area, wire downs per overhead mile,  
6       substation risk, and environmental justice (“EJ”).

7  
8       Within the 4.8kV ISO Conversion Program, the Company prioritizes investment  
9       allocation by circuit according to specific numeric criteria. Once the circuits are  
10      scored, ISO areas are grouped and prioritized at the substation level, meaning the  
11      Company performs work on a group of circuits, by substation. To prioritize or rank  
12      the substations, each ISO down is scored based on the factors listed below. The  
13      scores are totaled for the circuits associated with each substation, resulting in the  
14      overall substation score.

- 15           1) Recorded wire downs
- 16           2) Total substation System Average Interruption Duration Index (“SAIDI”)
- 17           3) Total outage and non-outage events, such as low voltage, which require the
- 18           dispatch of a line crew

19  
20      For efficiency purposes, the Company performs the work on all ISOs within a  
21      substation area as it is more efficient to perform the work for the group of circuits  
22      tied to the same substation. Converting all ISO down areas within a substation area  
23      at one time drives design and construction synergies while realizing operational  
24      benefits through newly established jumpering points.

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1 While the projects within the program are usually prioritized according to the  
2 numerical ranking described above, the Company also incorporates flexibility into  
3 the execution of the projects by recognizing that there are instances where load  
4 growth and the need for operational flexibility may result in reprioritization of  
5 projects.

6

7 **Q46. What is the status of the projects within the 4.8kV ISO Conversion Program?**

8 A46. As of March 31, 2025, the Company had initiated conversion work on the six  
9 highest priority substations and several individual circuits, which are shown in  
10 Tables 4 & 5 below.

11

12

**Table 4 ISO Conversion Substation Rankings**

| Ranking | Substation | Community       | 4.8kV Miles to Convert |
|---------|------------|-----------------|------------------------|
| 1       | Camden     | Pontiac         | 3.9                    |
| 2       | Kern       | Pontiac         | 4.8                    |
| 3       | Gilbert    | Romulus         | 7.5                    |
| 4       | Biddle     | Wayne           | 18.1                   |
| 5       | Brazil     | Madison Heights | 10.5                   |
| 6       | Venoy      | Garden City     | 18.6                   |

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**Table 5 ISO Conversion Individual Circuit Areas**

| Driver      | Circuit   | Community    | 4.8kV Miles to Convert |
|-------------|-----------|--------------|------------------------|
| Reliability | SPRUC9836 | Ann Arbor    | 0.4                    |
| Capacity    | WIXOM8239 | South Lyon   | 1.2                    |
| Capacity    | WIXOM8905 | South Lyon   | 3.0                    |
| Capacity    | SALEM9900 | Salem        | 1.3                    |
| Capacity    | SALEM9926 | Salem        | 1.4                    |
| Capacity    | NRBRN8808 | North Branch | 7.2                    |
| Reliability | BCKLR9936 | Ann Arbor    | 1.6                    |
| Reliability | WLVRN9834 | Ann Arbor    | 1.8                    |

2

3 As of March 31, 2025, the Company completed 10.7 miles of pre-conversion and  
4 0.7 miles of conversion as part of the ISO down program.

5

6 **IV. City of Detroit Infrastructure (“CODI”) Conversion Program**

7 **Q47. Can you explain the CODI Conversion Program?**

8 A47. The CODI Conversion Program, or “CODI Program” for short, is a specific set of  
9 conversion projects developed in 2015 to upgrade the oldest parts of the system in  
10 the inner core of the city of Detroit. The geographical footprint of the CODI  
11 Program includes residential and commercial areas, hospitals, universities, and  
12 sports venues within the city of Detroit. As I will explain further in the discussion  
13 of program drivers, the system in this area is different in design than the rest of the  
14 service territory due to a high load density in an urban downtown area with space  
15 restrictions, which required an all-underground system, including an alternating

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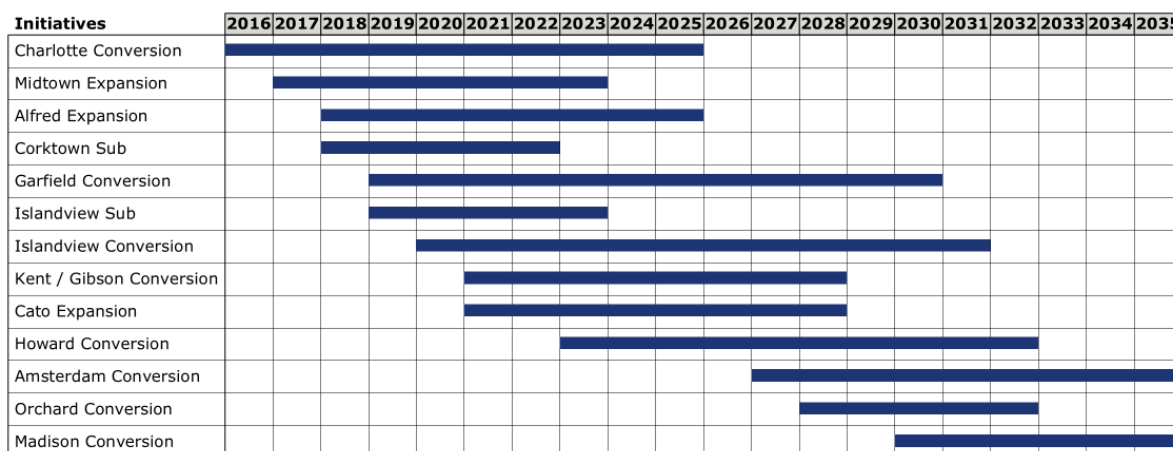
1 current network (or “AC network”) with elevated service transformers. The 4.8kV  
2 and 24kV portions of the system were constructed in the 1920s. Therefore, the  
3 CODI program was created to address this specific area while all other potential  
4 City of Detroit conversion projects fall under the 4.8kV CC category.

5  
6 The CODI Program includes thirteen projects (Figure 8) designed to provide  
7 capacity while addressing the aging infrastructure by converting and consolidating  
8 substations, the AC network, and associated overhead circuits in the CODI footprint  
9 (Figure 9). It includes:

- 10 • Reconfiguring of two 120kV/13.2kV Class A substations (Temple and  
11 Stone Pool) to 120kV/13.2kV Class S AC Network capable substations;
- 12 • Construction of two new 120kV/13.2kV Class A substations (Corktown and  
13 Islandview);
- 14 • Expansion of three existing 120kV/13.2kV substations (Midtown, Alfred,  
15 and Cato);
- 16 • Decommissioning nine 24/4.8kV substations (Charlotte, Walker, Howard,  
17 Kent, Gibson, Garfield, Amsterdam, Madison, and Orchard)
- 18 • Conversion and consolidation of the AC network (*i.e.*, 4.8kV system to  
19 13.2kV system);
- 20 • Conversion and consolidation of the associated overhead circuits from  
21 4.8kV to 13.2kV; and
- 22 • Decommissioning the aged underground 4.8kV all-underground  
23 distribution system and the 24kV sub-transmission system

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**Figure 8 CODI Strategy Projects**



2

3 The projects within the CODI program require complex system shutdowns in a  
4 congested downtown district that must be managed carefully due to the critical  
5 customer loads that will be impacted, including hospitals, federal and municipal  
6 emergency centers, and multiple corporate headquarters. The CODI program is  
7 sequenced to perform the needed upgrades in a manner that is least impactful to  
8 customers.

9 **Q48. What portions of the city of Detroit are addressed by the CODI program?**

10 A48. As shown in Figure 9, the CODI Program's core area includes the Downtown,  
11 Midtown, and New Center areas of Detroit, and the conversion of the 4.8kV all-  
12 underground distribution system that feeds it. The core area is generally bounded  
13 by Grand Boulevard to the north, the I-75 freeway to the east, the Detroit River to  
14 the south, and the M-10 Lodge freeway to the west. The 4.8kV all-underground  
15 distribution system is fed by a 24kV all-underground sub transmission system,  
16 which also feeds substations outside of the core area. These substations serve  
17 predominantly overhead distribution load but are included to fully realize the

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1 decommissioning of the 24kV system in the core area. These areas also have  
2 similar drivers such as increased development and aging infrastructure and are  
3 known as the “extended area”. As a result, projects within the CODI Program will  
4 increase capacity, address load growth, decommission aged and failing  
5 infrastructure, and improve system reliability and safety in the extended areas  
6 shown on Figure 9, including Eastern Market, Corktown, Woodbridge, Islandview,  
7 Belle Isle, and the West and East River Fronts.

8  
9 **Figure 9 CODI Footprint - Program Core and Extended Areas**



10  
11 **Q49. Can you explain the distribution system in the CODI area, and how it differs**  
12 **from the remainder of the Company’s system?**

13 A49. The earliest electrical grid in Southeast Michigan was developed in the downtown  
14 area of the city of Detroit. Although predated by a Direct Current (“DC”) system  
15 first constructed in the early 1900’s, significant portions of the electrical



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1 Alternating Current (“AC”) infrastructure in Detroit were placed into service in the  
2 early part of the 20th century when the DC system was converted.

3  
4 The CODI core area consists of multiple all-underground Residential Distribution  
5 (“URD”), 4.8kV Loop Power Lines, and a large 120V/208V meshed AC Network  
6 located via manhole access in busy city-center streets and served from six  
7 24kV/4.8kV substations (Amsterdam, Charlotte, Garfield, Howard, Madison, and  
8 Orchard). This differs from the remainder of the Company’s distribution system  
9 that is predominantly radially fed from a single substation via overhead lines.

10 The extended area of the CODI footprint consists of three 4.8kV substations  
11 (Gibson, Kent, and Walker) served by the same 24kV subtransmission circuits that  
12 feed the core area.

13  
14 All of the 24/4.8kV substations in the core area serve a mix of distribution circuit  
15 types , including all underground 4.8kV Radial, Loop Power Line, AC Network,  
16 and small sections of overhead circuits. This area is also served by six existing  
17 120kV/13.2kV substations, including Alfred, Cato, Midtown, St. Antoine, Stone  
18 Pool and Temple, that feed all underground 13.2kV radial feeders, select primary  
19 systems and URDs. Stone Pool and Temple have also been constructed as  
20 120kV/13.2kV ring bus substations to support conversion of the 4.8kV AC  
21 Network system.

22  
23 More specifically, the AC Network distribution system is a meshed low voltage  
24 grid design with multiple, parallel primary sources originating from the same  
25 substation. While it is recognized industry wide as the most reliable circuit

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1 topology due to its design, this reliability advantage can only be preserved when  
2 the system is operated within its contingency design, which for the Company's AC  
3 Network is N-1.<sup>12</sup> As I'll explain in more detail in relation to Program drivers, the  
4 age of the system, including its components still in use beyond their useful life,  
5 results in the Detroit AC Network commonly experiencing concurrent failures.

6

7 **Q50. What are the drivers of the CODI Program?**

8 A50. The main drivers of the CODI Program are the load growth realized over the last  
9 decade, projected future load growth, aging infrastructure, and outdated system  
10 design, each of which is explained in more detail below.

11

12 Existing and Projected Load Growth/Capacity

13 The CODI area has experienced 9.5% load growth (31 MVA) in the last decade,  
14 with the potential for an additional 10% load growth by the end of 2035. The  
15 additional load growth already experienced is mainly driven by the completion of  
16 downtown development projects that were previously delayed by the pandemic,  
17 known new developer and economic development projects, and increased  
18 electrification in new developments due to EV charger installation and the use of  
19 electric heat as opposed to gas service. Some of the notable new load projects in

---

<sup>12</sup> In electrical contingency-based grid planning, the contingency state exists when there is a planned or unplanned loss/failure of a component of the electric power system (e.g., transformer, cable, wire or breaker). The "N-X" contingency plan, where "N" designates the number of pieces of equipment on the system and "X" designates the number of pieces of equipment lost/failed, is common amongst utilities.

- N-0 designates the system is normal
- N-1 (Single Contingency) designates a piece of equipment is lost/failed
- N-2 designates two pieces of equipment have been lost/failed
- N-1-1 designates initial loss/failure of a piece of equipment (Primary Contingency), followed by system adjustments, followed by another loss/failure of a piece of equipment (Secondary Contingency)

The Company plans its electric system for N-1 contingency.

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1 the last decade include Little Caesars Arena, David Whitney Building, Q Line Light  
2 Rail System, Wayne State School of Business and Hillberry Theater Expansion,  
3 Book Tower, David Stott Building, Detroit Pistons Performance Center, Wayne  
4 County Criminal Justice Center, the Ford Corktown Mobility campus at the former  
5 Michigan Central Depot, and the Huntington Bank Tower. These, along with  
6 dozens of other completed new build/renovations in the New Center, Midtown, and  
7 Central Business District areas of Detroit, have created significant load growth and  
8 economic momentum in the CODI area. Further, the Company anticipates this  
9 growth continuing with the pipeline of future projects, including but not limited to  
10 the Hudson site developments (including the second tallest skyscraper in Detroit)  
11 coming online, residential and hotel developments on the west riverfront, the  
12 expansion of the downtown Music Hall, the University of Michigan Campus of  
13 Innovation projects, Henry Ford Hospital South and East campuses, as well as other  
14 general load growth from smaller residential and commercial developments within  
15 the CODI footprint.

16

17 In addition, the existing AC Network system, operating at 4.8kV, is capacity  
18 constrained in local areas of growth because of the primary cable size, number of  
19 4.8kV network feeders, and small 4.8kV Netbank transformer kVA ratings, thus  
20 necessitating the conversion to a higher voltage class. Conversion allows for fewer  
21 network feeders to serve a given area of the system and larger 13.2kV Netbank  
22 sizes to be installed, thereby requiring less maintenance while increasing capacity.

23

24 The need for safe and reliable power in the CODI core area is an essential part of  
25 the revitalization of the city of Detroit, and supports the growth of Michigan's

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1 economy. To maintain the system integrity necessary to serve the increasing load  
2 in the area, the Company developed the CODI Program.

3  
4 Aging and Failing Infrastructure

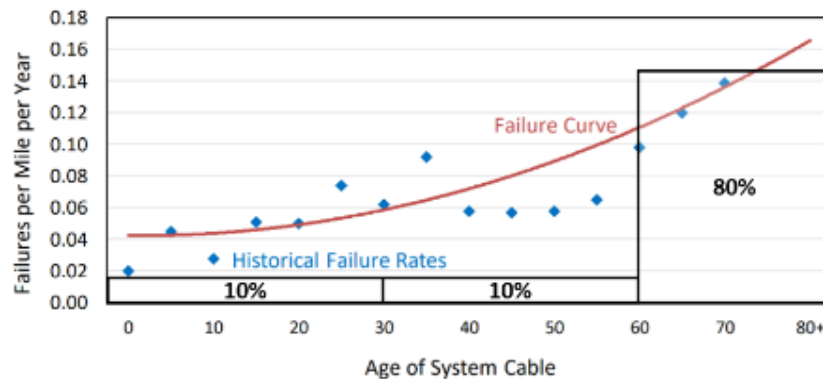
5 Aging infrastructure experiencing increased failure rates is another driver for the  
6 CODI Program. As I noted above, the system in Detroit was placed in service in  
7 the early part of the 20th century, and much of that original infrastructure remains.  
8 For example, the Garfield Substation was constructed in 1930 and still provides  
9 electrical service to the Midtown area of Detroit surrounding Wayne State  
10 University and the museum district. This substation has had several major events  
11 that have interrupted power to hundreds of residential and commercial customers  
12 in multiple blocks of Midtown due to failures of aging substation equipment and  
13 4.8kV and 600V system cable. Due to the complexity of the system, complete  
14 restoration has taken several days.

15  
16 Eighty percent (80%) of the existing 4.8kV and 24kV electrical infrastructure in the  
17 CODI footprint, including substations, underground cable, manholes, network  
18 equipment, and other assets, has been in service for over 60 years. While the system  
19 was designed for high reliability at the time, it has since aged to the point that  
20 increasing failure rates have compromised the inherent reliability of the system. As  
21 a result, the electrical infrastructure is considered “at risk” as evidenced by the  
22 historical failure rate curve shown in Figure 10 below.

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**Figure 10** CODI 4.8kV & 24kV mileage distribution over system failure rate curve

Moreover, the high failure rates increase the risk of long-duration outages, thereby impacting customers and leading to high reactive maintenance and capital costs to replace cables, repair conduit and manholes, and address adjacent hazards when found on trouble or new business/project jobs. These issues also contribute to significant delays in project and customer lead times when they need to be addressed. Customers in this area experience power outages and power quality issues from equipment failures related to aging infrastructure on the system. Namely, customers are experiencing outages and quality issues related to 4.8kV & 24kV cable, netbank transformer, and substation induction regulator failures—all due to aging infrastructure on these systems. On the radial 4.8kV and 13.2kV circuits the Company spends significant time in operating at Primary Switch Cabinets or Customer primary equipment to move the affected customers to backup circuits; this work can include staging and/or deploying diesel generators for N-1-1 contingencies. Furthermore, on the AC Network in particular, these failures have led to additional customer and system impacts, including cascading low voltage issues, grid fires, manhole eruptions, and customer outages. Table 6 lists the AC network failures, including N-1-1 and N-2 events that led to customer outages in the CODI core area from 2016 through 2024.

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**Table 6 CODI AC Network Outage Events (2016-2024)**

| YEAR         | FAILURE<br>EVENTS | N-1 | N-1-1 | N-2 | OUTAGE<br>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                |
| 2024         | 26                | 24  | 2     | 1   | 3                |
| <b>TOTAL</b> | 178               | 154 | 16    | 9   | 25               |

2

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13

As shown in Table 6, the downtown Detroit AC Network within the CODI core area has experienced 25 customer outage events since 2016, which is an average of 2.78 outage events per year; these outages will become more frequent as age related failure rates increase. By way of comparison, an average network served customer experiences an outage once every 58 years on an AC Network system.<sup>13</sup> Downtown Detroit AC Network customers have not only experienced significantly more outages than the average utility network customer, but these AC Network outages are also long duration events that are difficult to quickly restore as previously stated. Typical Customer Average Interruption Duration Index (“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).

<sup>13</sup> D. Smith and J. Moffat, “EPRI Underground Distribution Systems Reference Book” (City: Publisher, 2010), Chapter 12, p. 21.

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1 Relatedly, aside from the AC Network, the larger load customers in the CODI core  
2 area are served primarily by an all-underground radial feeder select power line  
3 system with manhole access located in busy city center streets, so accessing the  
4 manholes to do repairs often requires closing off traffic in these areas. Reliability  
5 in this area is also dependent upon having redundant capacity available on all power  
6 lines to transfer load in the event of cable failures or planned shutdowns on the  
7 distribution and sub transmission systems. Hospitals, for example, cannot tolerate  
8 a loss of load for even a short amount of time due to scheduled and emergency  
9 surgeries and procedures, and the CODI core area is home to many major medical  
10 facilities, such as DMC Harper Hospital, DMC Children's Hospital of Michigan,  
11 DMC Detroit Receiving Hospital, John D. Dingell VA Medical Center, Henry Ford  
12 North Campus, and the Henry Ford South and East Campuses which are currently  
13 under construction. Because of this critical need, the existing system is designed  
14 for N-1 contingency situations, which means that if a single trouble event occurs  
15 on the system at any one time, the system is still able to serve all load. The manhole  
16 system, however, typically supports multiple system cables, and a failure of one  
17 cable can impact adjacent cables resulting in cascading failures. Because there is a  
18 significant amount of aging high-risk cable and equipment, it compromises the  
19 reliability of the underground system. More specifically, with an increased number  
20 of trouble events, those events can occur simultaneously. In that instance, the event  
21 is beyond the original system design criteria (N-1-1 and N-2 events), and results in  
22 critical customer outages or complex contingency staging and planning of  
23 emergency equipment throughout downtown Detroit.

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1 When outage or next contingency (N-1-1) events occur in the CODI core area, the  
2 Company often has limited ability to respond and restore customers with alternative  
3 emergency measures (*e.g.*, portable substations, diesel generators, or circuit load  
4 transfers) because of the space constraints of the congested downtown  
5 environment, inaccessible underground Company infrastructure, and customer  
6 service gear located deep below grade in subbasements. These contingency plans  
7 are often not only time-consuming but extremely challenging to execute.

8  
9 Many manholes in this area have swollen or leaking lead sleeves, as shown in  
10 Figure 11 below. These sleeves pose a safety risk to the Company's underground  
11 crew because they have a higher likelihood of imminent failure. For that reason,  
12 the Company's underground work rules prohibit crew members from entering  
13 manholes with swollen and leaking sleeves unless the cables are de-energized  
14 before entry. De-energizing for safety can impact customers by requiring planned  
15 outages or diesel generator installation, which may require street/alley shutdowns  
16 in downtown. If the adjacent hazards are found on new business projects, it can  
17 increase project timelines thereby missing requested energization dates. As the  
18 infrastructure continues to age, the Company is experiencing increased frequency  
19 of this type of hazard in the same manhole. The Company, in turn, must undertake  
20 significant and impactful measures to address the hazards, including customer  
21 intentional interruptions, installation of temporary cable at grade, distributed  
22 generator staging installation in tight urban areas requiring street shutdowns, and  
23 expensive temporary re-routes of circuits just to address the safety issues and  
24 restore the system to normal.



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**Figure 11 Swollen and Leaking Lead Sleeves**

2

### Outdated System Design and Equipment

System design constraints are another driver of the 4.8kV CODI Program (Figure 12). First, the existing 4.8kV multi-level in-building substations are space constrained, making it difficult or impossible to install or replace infrastructure with modern equivalents or larger capacity equipment like transformers and regulators. Some equipment, like 4.8kV AC Network feeder section and stab switches are operated by hand and energized by personnel creating additional safety challenges. Other components like 4.8kV netbank transformers rely on outdated electromechanical relays to operate and do not have SCADA or DAS from which to remotely monitor loading on AC Network grids. Without the CODI Program, 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.

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**Figure 12 Risks Associated with Typical CODI System Equipment**

| Equipment                        |                                                                                   | Risks Associated with Equipment                                                                                                                                                                                                                                |
|----------------------------------|-----------------------------------------------------------------------------------|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| INDUCTION REGULATORS             |  | <ul style="list-style-type: none"> <li>Equipment is no longer commercially available for purchase</li> <li>Only 10 years max projected ability for equipment in-house refurbishment</li> </ul>                                                                 |
| LOOP POWER LINE SYSTEM           |  | <ul style="list-style-type: none"> <li>Deteriorating vault conditions</li> <li>Maintenance Challenge</li> <li>Suboptimal operating conditions</li> </ul>                                                                                                       |
| FEEDER STAB AND SECTION SWITCHES |  | <ul style="list-style-type: none"> <li>Only 10 years max projected ability for equipment in-house refurbishment</li> <li>Suboptimal operating conditions</li> </ul>                                                                                            |
| NETBANKS                         |  | <ul style="list-style-type: none"> <li>Only 10 years max projected ability for equipment in-house refurbishment</li> <li>Netbanks units available for new service or replacement are the refurbished units at Trombly and Warren Service Center</li> </ul>     |
| SECONDARY RUBBER CABLE           |  | <ul style="list-style-type: none"> <li>Creates a combustible gas when overloaded causing build up within the manhole (eject manhole covers)</li> <li>Burning secondary cables causes damage to adjacent cables</li> <li>Enhanced safety opportunity</li> </ul> |

2 **Q51. How does the CODI Program address the drivers you just described?**

3 A51. First, the CODI Program addresses existing and anticipated future load growth by  
4 installing new higher capacity substations and converting to a 13.2kV distribution  
5 system voltage with 2.75x the capacity of a 4.8kV system. Local areas of capacity  
6 constraints in AC Network areas are addressed with higher capacity netbank  
7 installations during conversion. Also, by eliminating the 24kV and 4.8kV cable  
8 systems, the amount of total system cable is reduced by 50% from 475 miles to 237  
9 miles at the end of the CODI program. Since cable ratings are limited by thermal  
10 heat given off by adjacent cables within a duct bank, the reduction in overall cable  
11 footage means that the existing and new 13.2kV circuits in the CODI footprint will  
12 have higher load carrying capability due to a smaller number of cables within a  
13 given duct run.

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1 Second, the CODI program addresses the aging infrastructure by completely  
2 decommissioning the 4.8kV and 24kV systems thereby retiring nine 4.8kV/24kV  
3 substations, 387 miles of aged 4.8kV and 24kV paper and lead cable and (415)  
4 4.8kV Netbank transformers. All newly installed cable will be ethylene propylene  
5 rubber (“EPR”) cable which has operational and construction advantages over the  
6 existing cable as I explain below. When the CODI Program was first developed in  
7 2015, the majority of the 24kV and 4.8kV cable in scope had a weighted average  
8 age of 65 years, with some of the oldest sections being beyond 90 years of service  
9 age. With the current target completion date of 2035, some remaining sections of  
10 4.8kV and 24kV cable will be in service for over 110 years at that point. With the  
11 failure rate of the originally designed paper and lead cable increasing with age,  
12 these cables must be replaced to maintain the integrity and reliability of the system.  
13 The benefits of the new cable are three-fold: (1) through conversion to 13.2kV, the  
14 system is consolidated and reduces the amount of necessary cable replacement by  
15 50% over like for like replacement at 4.8kV/24kV, (2) EPR splices are less costly  
16 and time intensive to construct, and (3) EPR does not have the same high failure  
17 rates and hazard issues that occur with lead joints.

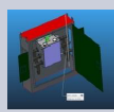
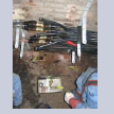
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19 The CODI Program addresses these system design constraints by replacing aged  
20 and outdated equipment with modern equivalents that use new technologies such  
21 as microprocessor relays, SCADA enabled devices for remote control, automatic  
22 isolation, and load monitoring, dead front equipment for safer operation, and low-  
23 smoke halogen free EPR cable for secondary grids to replace high risk butyl rubber  
24 and paper and lead cable. The replacement of high-risk butyl rubber and paper and  
25 lead cable is safer for our employees to operate and more reliable because paper

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and lead cable leads to frequent failures and adjacent hazards within the manhole systems within the CODI footprint. These benefits are shown in Figure 13 below.

**Figure 13 Benefits of Newly Installed Equipment in CODI Area**

| New Equipment                                     |                                                                                     | Benefits of New Equipment                                                                                                                                                                                                                                          |
|---------------------------------------------------|-------------------------------------------------------------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| LOAD TAP CHANGER                                  |    | <ul style="list-style-type: none"> <li>All new Subs 120kV/13.2kV</li> <li>Standard DTE Installation on all substations</li> <li>No phase shift with LTC during voltage regulation</li> </ul>                                                                       |
| MODERN LOOP POWER LINE SYSTEM (S&C VISTA SWITCH)  |    | <ul style="list-style-type: none"> <li>Maximize Primary Switch Cabinet Fuse positions downtown</li> <li>SF6 or Solid Dielectric</li> <li>Can be remote operated (locally or SCADA)</li> <li>Can be wall or vault mounted (submersible)</li> </ul>                  |
| MODERN FEEDER STAB AND SECTION SWITCHES (G&W SF6) |    | <ul style="list-style-type: none"> <li>200A or 600A elbow terminations</li> <li>Can be wall or enclosure mounted (alley or vaults)</li> <li>SF6 or Solid Dielectric</li> <li>Hook switch operated</li> <li>Load break or interrupting</li> </ul>                   |
| NETBANKS (COOPER)                                 |    | <ul style="list-style-type: none"> <li>First new replacement units in 20+ years</li> <li>FR3 Oil for low flash point against building or in-vault</li> <li>Microprocessor Protector as opposed to electro-mechanical</li> <li>Communication/SCADA ready</li> </ul> |
| SECONDARY SYSTEM (RAYCHEM)                        |  | <ul style="list-style-type: none"> <li>Low smoke halogen free cable</li> <li>New crab style mole reduce material by 95%</li> <li>Cut installation time in half</li> <li>Visible limiters indicate if secondary mains are compromised</li> </ul>                    |

Without CODI Program investments, the increasing failure rates of aged equipment, coupled with the load growth in the CODI core area, will increase the frequency of outage events that affect large portions of the downtown Detroit system. These events will impact more customers and become more expensive and complicated to repair and restore.

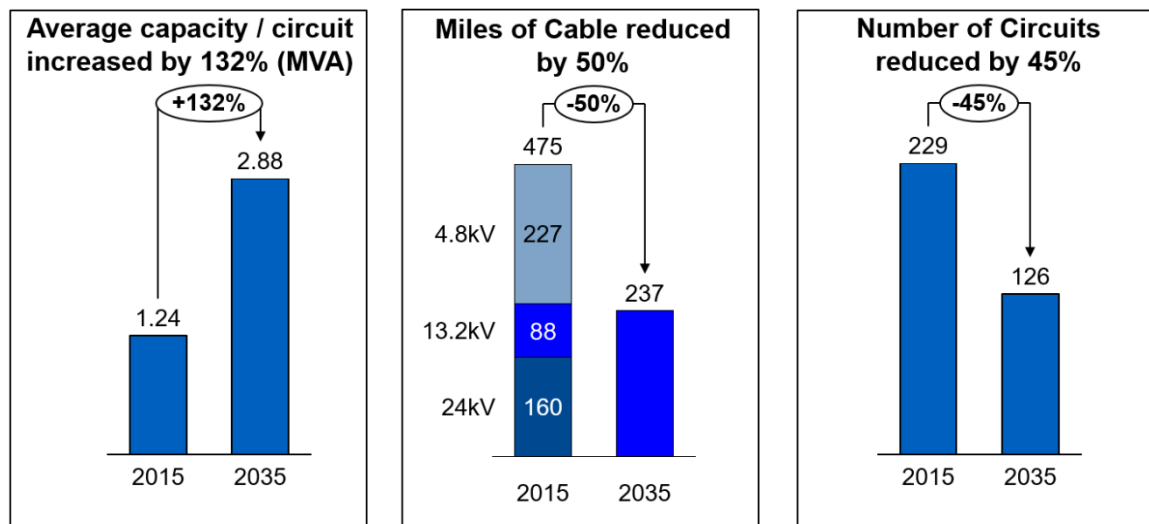
**Q52. What are the benefits of the CODI Conversion Program?**

A52. The figures below illustrate the benefits of the CODI Conversion Program in relation to addressing the drivers of load growth, aged and failing infrastructure, and outdated system design. Figure 14 shows the reduction of circuit infrastructure

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(number of circuits and miles of cable) via 13.2kV conversion while still increasing capacity for known developments and future load growth and electrification. The reduction in cable infrastructure also has reliability and operability benefits. The weighted average age (“WAA”) of the system cable at the end of the CODI project will be reduced from 75 years to 20 years thereby reducing failure rates. As stated above, the use of EPR cable will eliminate adjacent hazards from leaking and swollen sleeves on the upgraded portions of the system.

**Figure 14 CODI Circuit Benefits**



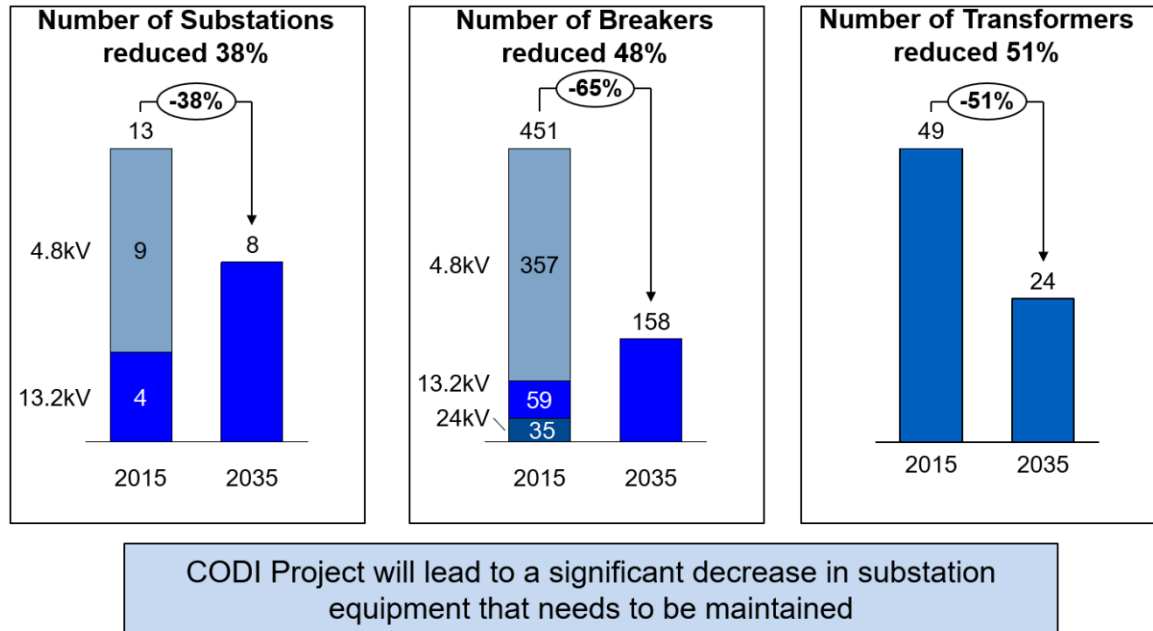
CODI Project will add much needed capacity to the system while reducing the number of circuits and miles of cables that need to be maintained

The benefits of the CODI program also extend to the substation infrastructure in the area. Through conversion, the number of substations serving the area will be reduced from thirteen to eight. The modern modular substation design of these substations also reduces the number of breakers required for circuit protection by 65% and power transformers by 51%. This in turn reduces substation operator time

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for switching and protection, and O&M costs for periodic and corrective maintenance (Figure 15).

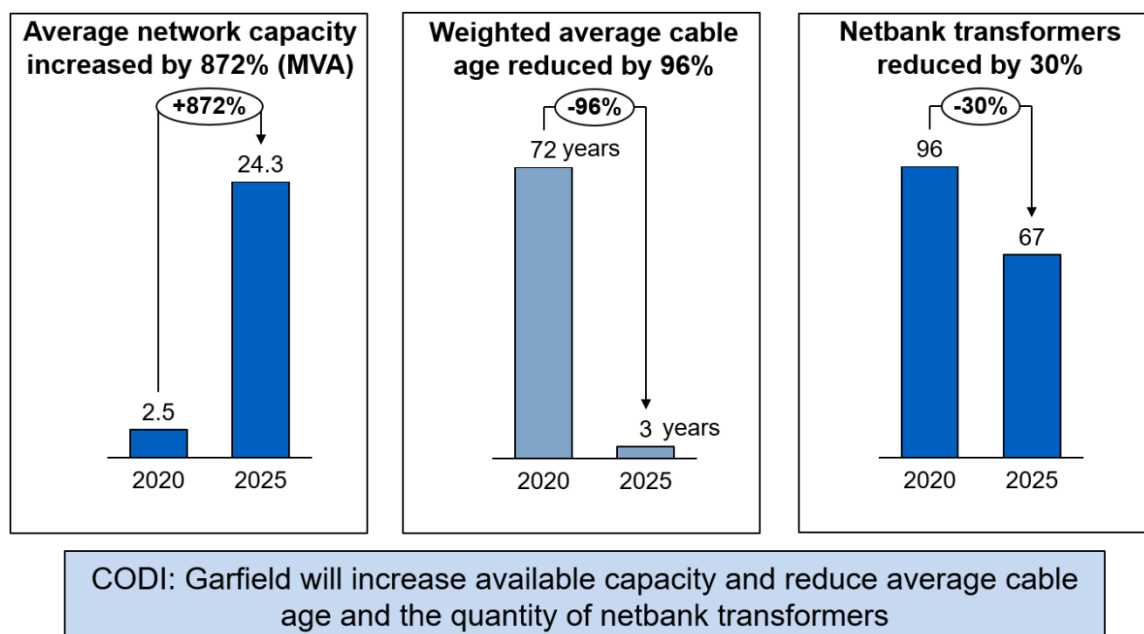
**Figure 15 CODI Substation Benefits**



The Detroit AC Network, which is the most aged system within the CODI footprint, will realize several benefits from the CODI Program, including capacity increases, reduced risk, and improved reliability due to aged infrastructure replacement and asset consolidation. In the CODI Garfield project for example (Figure 16) the WAA of the system cable will be reduced from 72 years to 3 years at project end and the number of netbank transformers on the new system will be reduced by 30% by using larger units and re-spacing due to current grid loading. Even though the number of units are reduced, the ultimate primary Network Feeder capacity will be increased by 21%, allowing the system capacity to be increased by adding more transformers on New Business requests as load grows.

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**Figure 16 CODI Garfield AC Network Benefits**



2

3 **Q53. What did the Commission say with respect to the Company's CODI**  
4 **investments in the last electric rate case, Case No. U-21534?**

5 A53. The Commission found that "DTE Electric reasonably supported its conversion  
6 capital expenditures requested for the historical, bridge, and test years in this case,  
7 including those related to the company's CODI program."<sup>14</sup>

8

9 **Q54. What CODI Program projects are included in this case?**

10 A54. Table 7 provides a high-level summary of the projects in the CODI program with  
11 additional details provided in Exhibit A-23 Schedule M6.

<sup>14</sup> U-21534 - Commission Order, January 23, 2025, p. 124.



**Table 7 CODI Program Projects**

| Table 7 – CODI Projects                            |                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                           |
|----------------------------------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Project Name                                       | Drivers                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                   |
| CODI: Corktown Substation                          | Corktown is a general-purpose substation that was proposed as part of the CODI upgrade to provide capacity needed to serve fast growing Detroit core downtown areas. This substation will also help consolidate, convert, and eliminate the 4.8 kV distribution and 24kV subtransmission system in the Corktown/West River Front area. A significant portion of the associated infrastructure (system cable/conductor, circuit breakers) are at end-of-life. This project was completed in 2023.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                          |
| CODI: Islandview Substation                        | <p>Islandview substation and circuit conversion is a key component of the City of Detroit Infrastructure (CODI) plan, which addresses load demand and aging infrastructure. New customer load from the East Detroit Riverfront cannot be reliably served by the 4.8kV infrastructure at Walker (WALKR) and Pulford (PULFD) substations. The new Islandview substation will also provide capacity to serve customers being transitioned from the Detroit Public Lighting Department system to the DTE Electric system. Walker and Pulford substation have aging infrastructure as they were built over 90 years ago. Many pieces of equipment do not have spare parts available. Some assets have been identified for increased risk of failure including transformers, regulators, oil circuit breakers and disconnects, 4.8kV and 24kV underground cable.</p> <p><u>Safety:</u> Minimize risk of energized downed wire.</p> <p><u>Reliability:</u> Systems have been dismantled over time due to failures and many pieces of equipment have no spare parts. Many assets are identified as medium/high risk for failure and would require significant time to repair: 23 miles of 90-year-old underground 24kV cable, 40 miles of 72-year-old underground 4.8kV cable, 47 oil circuit breakers and disconnects, and 3 transformers and 18 regulators.</p> <p><u>Capacity:</u> New customer load has been added along the Detroit riverfront (8.1MVA in 2019 and 2020). Additional developments and conversions from Detroit Public Lighting Department (PLD) are now in-service.</p> <p><u>Operability:</u> New manholes and switch cabinets will be used to setup the future underground circuits for improved system configuration and operability.</p> |
| CODI: Alfred Substation Expansion                  | <p>Alfred (ALFRD) is a two transformer Class A substation that serves Detroit's Central Business District and East Riverfront areas. The City of Detroit Infrastructure Project (CODI) was implemented to align strategies between serving new load and addressing aging infrastructure. This CODI project is proposed to expand ALFRD substation to help to eliminate the 4.8kV distribution and the 24kV subtransmission trunk lines in the Midtown area. Drivers for the project include the following:</p> <p><u>Capacity:</u> The substation is currently 92% of firm and cannot support the future area load growth.</p> <p><u>Operability:</u> Installing a second set of switchgear and a third 24/32/40 MVA transformer along with diversifying exit conduits will improve operability.</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                      |
| CODI: Midtown Substation Expansion                 | <p>The Midtown Substation Expansion project is part of the City of Detroit Infrastructure (CODI) plan which addresses loading and aging infrastructure. Midtown (MIDTN) is a 2 transformer Class 'A' general purpose substation constructed in 1973 that serves downtown Detroit New Center and Midtown areas. This project will expand MIDTN substation. Drivers for this project include the following:</p> <p><u>Capacity:</u> The substation is currently 81% of firm and cannot support approximately 20MVA of future known load growth. The new load growth would place the substation at 146% of its firm rating.</p> <p><u>Operability:</u> Installing a second set of switchgear and a third 24/32/40 MVA transformer along with diversifying exit conduits will improve operability.</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                        |
| CODI: Targeted Network Secondary Cable Replacement | This cable program is designed to replace targeted 4.8 kV secondary network cable system in Detroit that has a higher probability of failure. This will reduce the secondary network cable failures and manhole events in downtown City of Detroit.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                       |
| CODI: Charlotte Network Upgrade                    | <p>Charlotte substation is located in Downtown Detroit and is over a century old with no available capacity for incremental load growth. There's been recent load growth and development resurgence in the Charlotte area. This project is part of the City of Detroit Infrastructure (CODI) Initiative, directed to eliminate the 4.8kV and 24kV voltage classes. The primary driver for this project is to provide capacity for near-term load growth while a secondary driver is the consolidation of assets and replacement of aging infrastructure.</p> <p><u>Reliability:</u> This project will consist of replacing aging infrastructure such as cable, netbanks, transformers, and install sectionalizing devices.</p> <p><u>Capacity:</u> Primary voltage will be converted from 4.8kV to 13.2kV which will provide additional capacity in the area for future load growth.</p> <p><u>Operability:</u> SCADA will be implemented on all new netbanks and net feeders.</p> <p><u>Other:</u> Network primary voltage will be converted from 4.8kV to 13.2kV to improve safety, reliability, modernize the grid and provide additional capacity in the area for future load growth.</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                             |
| CODI: CATO Substation Expansion                    | <p><u>Safety:</u> CATO powerlines, like most downtown lines, consist of old 4.8kV or 15kV paper and lead cable</p> <p><u>Reliability:</u> CATO is currently fed by two underground 120kV lines which cause reliability issues for customers during work and extensive contingency plans</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                               |



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| Table 7 – CODI Projects      |                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                     |
|------------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Project Name                 | Drivers                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                             |
|                              | <p><u>Capacity:</u> CATO 13.2kV Class “A” is currently at 87% Firm and needs to be expanded to facilitate the future conversions of CATO 4.8kV and ORCHD 4.8kV substations</p> <p><u>Operability:</u> Should failure occur, repair work could take up to eight weeks for critical customers served with “Cato-Cato” throwovers</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                  |
| CODI: Kent/Gibson Conversion | <p>The Kent/Gibson Conversion project is part of the greater City of Detroit Infrastructure (CODI) which was implemented to serve new load and address aging assets. This project will help serve load along the West Detroit Riverfront which currently can’t be served reliably with the 4.8kV infrastructure. The project will utilize the newly built 13.2kV Corktown substation to convert and consolidate the 4.8kV in the area to 13.2kV. Drivers for this project include the following:</p> <p><u>Reliability:</u> Gibson substation was built in 1948 with aging infrastructure and at-risk equipment. 100% of the system cable at Gibson substation is considered at-risk. Kent substation was built in 1960 and contains at risk equipment. 99% of the system cable at Kent substation is considered at-risk. Kent and Gibson substations both experience outages which exceed the system average.</p> <p><u>Capacity:</u> Gibson substation is 101% of its firm rating. Kent substation is 72% of its firm rating but the individual circuits have limited capacity.</p> <p><u>Operability:</u> Kent and Gibson circuits currently do not have any loop schemes and have limited to no sectionalizing. Neither substation has any automatic operating points and have limited protective devices.</p>                                  |
| CODI: Garfield               | <p>The Garfield project is part of the City of Detroit Infrastructure (CODI) plan, which addresses load demand and aging infrastructure. Garfield substation is to be decommissioned and its circuits converted to nearby 13.2kV substations. Drivers for the project include the following:</p> <p><u>Safety:</u> Garfield substation is a 4.8 kV substation that is over 90 years old</p> <p><u>Reliability:</u> A resurgence of development in Detroit in recent years has resulted in increased loading on these aged, often end-of-life assets on both the radial and AC Network system</p> <p><u>Capacity:</u> New 13.2kV circuits from Midtown substation will support Detroit’s Eastern Market, Milwaukee Junction and Midtown areas, removing load from aging 4.8kV substations. Approximately 5.5 MVA of additional load from new developments in Milwaukee Junction and Midtown cannot be served by the area’s 4.8kV distribution system. The AC Network has a limited capacity of 2.5 MVA remaining.</p> <p><u>Operability:</u> New radial circuits will be fully automated, including loop schemes and automated pole top switches. Appropriate sectionalizing devices, automatic and manual, will be installed to isolate circuit to ~200 customers per zone. The AC Network netbanks and netfeeders will have SCADA implemented.</p> |

1

2 **Q55. Are any CODI investments included in the Infrastructure Recovery**  
3 **Mechanism (IRM)?**

4 A55. Yes. The Company’s CODI investments are partitioned between recovery through  
5 base rates and the Company’s authorized IRM mechanism. For the historical,  
6 bridge and test periods in the instant case, Exhibit A-12 Schedule B.5.4.8 shows  
7 the partition between the base rates requested in Exhibit A-12 Schedule B5.4 and  
8 authorized IRM amounts shown in Exhibit A-33 Schedule X1. Company Witness  
9 Willis discusses the background of the IRM and supports the inclusion of  
10 investments in the IRM. CODI prioritization in the IRM will follow the GPM  
11 prioritization as described by Company Witness Kryscynski, which includes using  
12 the EJ multiplier.

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1 **V. 8.3kV Pontiac Conversion Program**

2 **Q56. Can you please describe the Company's 8.3kV voltage area on its distribution**  
3 **system?**

4 A56. The Company has only one 8.3kV voltage area in its distribution system, and it is  
5 in and around the city of Pontiac. The Company acquired the 8.3kV system from  
6 CMS Energy in the 1980s, and the specific details about the system can be found  
7 in Exhibit A-23 Schedule M8 DGP starting on page 123. For purposes of my  
8 testimony, the important points about the 8.3kV system are that it is unique to the  
9 Company's overall system and limited to one specific geographic area. The  
10 uniqueness of the 8.3kV system and its limited geographic area impact operability  
11 and reliability for the Company and customers in this area. The system design also  
12 brings unique safety challenges for employees operating and maintaining the  
13 system.

14

15 **Q57. What is the 8.3kV Pontiac Conversion Program?**

16 A57. The Company initiated the 8.3kV Pontiac Conversion Program in 2010 to address  
17 operational challenges associated with the 8.3kV system and to replace aging,  
18 failing, and obsolete infrastructure. This program is focused on converting the  
19 8.3kV system in and around Pontiac to 13.2kV.

20

21 **Q58. What are the drivers of the 8.3kV Pontiac Conversion program?**

22 A58. Because of the unique voltage in a limited geographic area, the Company has  
23 limited contingency options through jumpering to support alternate routing of  
24 power during planned and emergent outage situations. The 8.3kV circuits can only

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1 be restored or tied to other 8.3kV circuits whereas the surrounding area is 13.2kV.

2 This results in high risk for stranded load in the event of an 8.3kV outage event.

3

4 Adding to this operational challenge, the 8.3kV system is aging, and the equipment  
5 is failing and obsolete, so the Company is unable to source replacement equipment.

6 Further, as new load develops, it is difficult to connect that load to the system due  
7 to the obsolete equipment and limited capacity. The system has failing substation

8 equipment that requires significant modification of the existing steelwork to

9 accommodate new standardized equipment. Existing substations lack appropriate

10 safety-related clearances, requiring all circuits to be shut down to perform any

11 maintenance or repairs, thus resulting in more customer outages during

12 maintenance or repairs. When 8.3kV equipment fails, circuit shutdowns lead to

13 extended customer interruptions during outage events and leave the system in an

14 abnormal state for extended periods of time. These issues with the 8.3kV system

15 have been ongoing and impact many customers. For example, on August 19, 2024,

16 an emergent equipment failure at Rapid Street Substation occurred requiring 1,156

17 customers to be placed out of service to facilitate the repair, some up to 12 hours.

18

19 The removal of at-risk, outdated, and obsolete 8.3kV equipment from the system  
20 will reduce emergent costs and improve response time for customer restoration.

21 Additionally, the 8.3kV conversion program is necessary to increase capacity and

22 improve reliability, safety, and operability.

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1   **Q59. What are the benefits of the 8.3kV Pontiac Conversion Program?**

2   A59. The 8.3kV Pontiac Conversion Program will provide additional capacity, which  
3       will serve any incoming load and better prepare the area for adoption of EVs, DERs,  
4       and future needs. The projects included in this program will collectively increase  
5       capacity by 17% and will completely decommission the 8.3kV infrastructure in the  
6       Pontiac area. Additionally, this work will support a reduction of up to 90% in  
7       customer minutes of interruption, wire downs, and trouble events through the  
8       rebuild of the 8.3kV infrastructure to current 13.2kV standards. Converting the  
9       Pontiac system to 13.2kV also provides jumpering points from nearby 13.2kV  
10      substations, which will improve system operability and reduce outage restoration  
11      time by allowing the Company to restore customers prior to repairing damaged  
12      infrastructure, (commonly described as “restore before repair”).

13

14   **Q60. What progress has the Company made on implementing the 8.3kV Pontiac**  
15    **Conversion Program?**

16   A60. The 8.3kV system is currently served by three substations: Bartlett, Rapid Street,  
17       and Stockwell Substations via their combined 17 distribution circuits. The program  
18       started with the upgrade of system underground vaults, which is anticipated to be  
19       completed by the end of 2025. The following scope has already been completed:

- 20       • A new 13.2kV circuit converted and transferred partial load from Stockwell  
21       Substation in 2016
- 22       • Emergency load relief plans were implemented by installing temporary ISO  
23       down transformers in 2017
- 24       • Remaining load from 8.3kV Paddock Substation was converted and  
25       transferred to Catalina Substation in 2024.

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1 Additional project detailed information is provided in Exhibit A-23 Schedule M6  
2 as well as Section 9.3.7 of Exhibit A-23 Schedule M8 DGP.

3

4 **Q61. How was the Company's 8.3kV Pontiac Conversion Program investments**  
5 **addressed in the Case No. U-21534?**

6 A61. As I noted above, the Commission found that the Company "reasonably supported"  
7 its conversion programs.<sup>15</sup> This included the 8.3kV Conversion Program. The  
8 Commission also expressed its intention to consider the Audit Report in Case No.  
9 U-21305 for future discussions surrounding the 8.3kV Pontiac Conversion  
10 Program; I address this below.

11

12 **Q62. The Audit Report suggested the Company re-examine its justification for the**  
13 **8.3kV Pontiac Conversion Program.<sup>16</sup> Do you agree with that**  
14 **recommendation?**

15 A62. Respectfully, I do not agree that the Company should re-examine its justification  
16 for the 8.3kV Pontiac Conversion Program. As previously explained, the Pontiac  
17 challenge is not fully and specifically capacity related and the other challenges in  
18 the area are significant, including safety, operability and reliability challenges of a  
19 small, aged and isolated unique voltage. Unlike the 13.2kV system, contingency  
20 options are limited for the Pontiac 8.3kV system because it is an island surrounded  
21 by the 13.2kV system, preventing easy transfers of load to neighboring facilities. I  
22 explained the contingency limitations above in Q&A 58. With the load in the  
23 Pontiac 8.3kV system having gradually increased over the past seven years, this

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<sup>15</sup> Case No. U-21534 - Commission Order, January 23, 2025, p. 128.

<sup>16</sup> Audit Report, Part 2 at 85.

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1 results in a higher risk for greater stranded load in the event of an 8.3kV substation  
2 outage event.

3

4 **Q63. What is the remaining scope of the 8.3kV Pontiac Conversion Program?**

5 A63. The remaining scope includes expanding the existing 13.2kV Catalina and Wheeler  
6 Substations to establish the capacity needed to facilitate conversion of the 8.3kV  
7 circuits. The additional capacity is needed to serve new and anticipated customer  
8 load. As of March 2025, the Company has received the following requests for  
9 incoming load, which will be realized between 2026 and 2028:

- 10 • Government office relocation at Judson (estimated load 1.2MVA)
- 11 • Mixed-use development at Huron and Woodward (estimated 3.5MVA)
- 12 • Mixed-use development at Crystal Lake (estimated 1.5MVA)

13

14 **Q64. What are the 8.3kV Pontiac Conversion Program project investments**  
15 **included in the instant case?**

16 A64. Table 7 below provides the high-level summary of the 8.3kV Pontiac Conversion  
17 Program projects included in this case. Detailed information for each of these  
18 projects is provided in Exhibit A-23 Schedule M6.

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**Table 8 8.3kV Pontiac Conversion Projects**

| Project Name                                                               | Drivers                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                  |
|----------------------------------------------------------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| 8.3 kV CC: Pontiac Overhead Conversion<br><br>(Catalina Phase 3 & Wheeler) | <p>DTE acquired the 8.3kV distribution system in the City of Pontiac from Consumers Energy in the 1980s. This project will convert and consolidate portions of the 8.3kV system to 13.2kV. Drivers for the project include the following:</p> <p><u>Safety:</u> 8.3kV causes a higher safety risk to employees in the event of failure due to aging and obsolete equipment</p> <p><u>Reliability:</u> The 8.3kV system is failing and spare parts for some of the equipment (such as breakers and 40-8.3kV substation transformers) are unavailable. Combined factors such as unavailable replacement parts, multiple abnormal configurations, etc. significantly impact the duration of shutdowns and restoration efforts leading to prolonged interruptions.</p> <p><u>Operability:</u> Pontiac's 8.3kV distribution system is an island surrounded by 13.2kV infrastructure.</p> <p><u>Capacity:</u> There are limited restoration capabilities - there is the potential of 13.9 MVA of stranded load</p>                                                                                                                                                                                                                                                                                                                             |
| 8.3 kV CC: Pontiac Underground Conversion                                  | <p><u>Safety:</u> Significant hazards exposure to employees while attending aged, failing, obsolete Pontiac 8.3 kV System</p> <p><u>Reliability:</u> Significant stranded load exposure in the event of 8.3kV substation outage event. Unique 8.3 kV Distribution System is an island surrounded by 13.2 kV System.</p> <p><u>Operability:</u> Increased complexity of restoration efforts. Replacement parts are no longer available for 8.3 kV breakers due to their obsolescence. Aged 8.3 kV system serves 8.5MVA of UG System load and over 900 customers. Several critical services are supported through 8.3kV rated underground equipment. These services contain customer-owned switchgear, fuses, and transformers. Replacement of the 8.3 kV substations with 13.2 kV infrastructure requires the replacement of these services with 15kV rated equipment to enable load transfers. Combined challenges lead to extended customer interruptions during outage events and strains system in abnormal state for extended periods during 8.3 kV equipment failures.</p> <p><u>Capacity:</u> Diminishing capacity to support City of Pontiac load. Unique voltage equipment is obsolete, failing, scheduled for retirement. Pontiac is experiencing an economic rebound, with 4.7MVA of new developments in downtown Pontiac.</p> |

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1 **VI. System Loading Projects**

2 **Q65. What is a System Loading Project?**

3 A65. System Loading Projects are capital investment projects to address system  
4 overloads on the distribution system, in order to mitigate overloads, improve  
5 reliability and provide capacity for new and existing customers. These projects are  
6 generally focused on the 13.2kV system but may include 4.8kV areas if full 13.2kV  
7 conversion of the area is not warranted at this time. A system overload occurs on  
8 a circuit or substation when there is insufficient capacity in certain operating  
9 conditions to meet customer demands while maintaining grid operation within  
10 equipment operating ratings. System Loading Projects alleviate the stress on the  
11 system caused by overloads and reduce potential failures. These projects also  
12 increase capacity and reconfigure the system to eliminate projected overloads on  
13 specific pieces of equipment (overhead wire, underground cable, transformers), or  
14 at the circuit/substation level, and in some cases the added capacity allows for  
15 future projected load growth.

16

17 Additionally, System Loading Projects help maintain/improve system operability  
18 by restoring/creating jumpering capabilities and removing aged equipment from the  
19 system. System Loading Projects increase capacity of the distribution system, by  
20 adding/upgrading equipment at existing substations, or constructing new  
21 substations. Potential scope details could include:

- 22 • Construction of new substations (which may include land acquisition);
- 23 • Expansion of current substations by installing additional transformers;
- 24 • Replacing existing transformers;
- 25 • Installing new switchgear lineups;



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- 1           • Creating new distribution circuits;
- 2           • Reconductoring circuits (overhead wire and/or underground cable);
- 3           • Converting circuits to higher voltage, where necessary and transferring
- 4           load once additional capacity has been created.

5

6   **Q66. Can you describe a system overload?**

7   A66. System overloads occur on a circuit or substation when there is insufficient capacity  
8       to meet customer demands while maintaining grid operation within equipment  
9       operating ratings. Capacity needs are analyzed for two conditions: normal state and  
10       contingency state. The normal state exists when all equipment and components are  
11       in service and operating as designed. The contingency state exists when there is  
12       either a temporary, planned equipment shutdown or the unplanned loss/failure of a  
13       component of the electric power system (*e.g.*, transformer, cable, or breaker). Under  
14       contingency state conditions, equipment in the rest of the system may see an  
15       increase in loading to compensate for the out-of-service equipment, delivering  
16       additional power above normal state.

17

18       To meet the normal and contingency state capacity needs of the system, most  
19       components and equipment have two ratings: day-to-day and emergency. These  
20       ratings are calculated to maintain the viability of an asset throughout its expected  
21       useful life. Operating equipment above its designated ratings can cause immediate  
22       failure or accelerate end-of-life and is considered an overload. DTE Electric  
23       definitions for day-to-day rating, emergency rating, and substation firm rating are

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1 consistent with industry definitions such as those available from National Electrical  
2 Reliability Corporation,<sup>17</sup>

- 3 • The day-to-day rating (for normal state conditions) is the load level at which  
4 the equipment can be operated for its expected life span.
- 5 • The emergency rating (for contingency state conditions) is typically higher  
6 than the day-to-day rating and indicates the load level at which the  
7 equipment can operate for short periods of time only. Operating towards the  
8 emergency rating adds stress to the equipment and may shorten its lifespan.  
9 If a piece of equipment exceeds its emergency rating, the Company's ESOC  
10 personnel will take immediate steps to transfer load to adjacent circuits or  
11 shed load, thus subjecting customers to outages, if necessary.

12  
13 Substations also have a 'firm rating', which is the maximum load the substation can  
14 carry under a single contingency condition and is based on the lowest emergency  
15 rating of any substation equipment that is required to serve the load, such as  
16 incoming subtransmission feed, transformer, and secondary cables.

17  
18 Figure 17 below shows an illustration of a two-transformer substation with a firm  
19 rating of 25 MVA. Transformer 1 has an emergency rating at 25 MVA, and  
20 Transformer 2 has an emergency rating at 30 MVA. Transformer 1 has the lowest  
21 emergency rating of the equipment inside the substation, therefore 25 MVA is the  
22 firm rating of the substation in this example. Under normal operation, both  
23 transformers serve customer load that they are designed to serve. In a single

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<sup>17</sup> Glossary of Terms Used in NERC Reliability Standards, available at  
[https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary\\_of\\_Terms.pdf](https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf), accessed March 12,  
2024

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contingency situation, such as the failure of a transformer or loss of a subtransmission feed, automatic operations will occur within the substation and customer load will continue to be served to avoid a large, sustained outage.

**Figure 17 Substation in Normal Configuration**

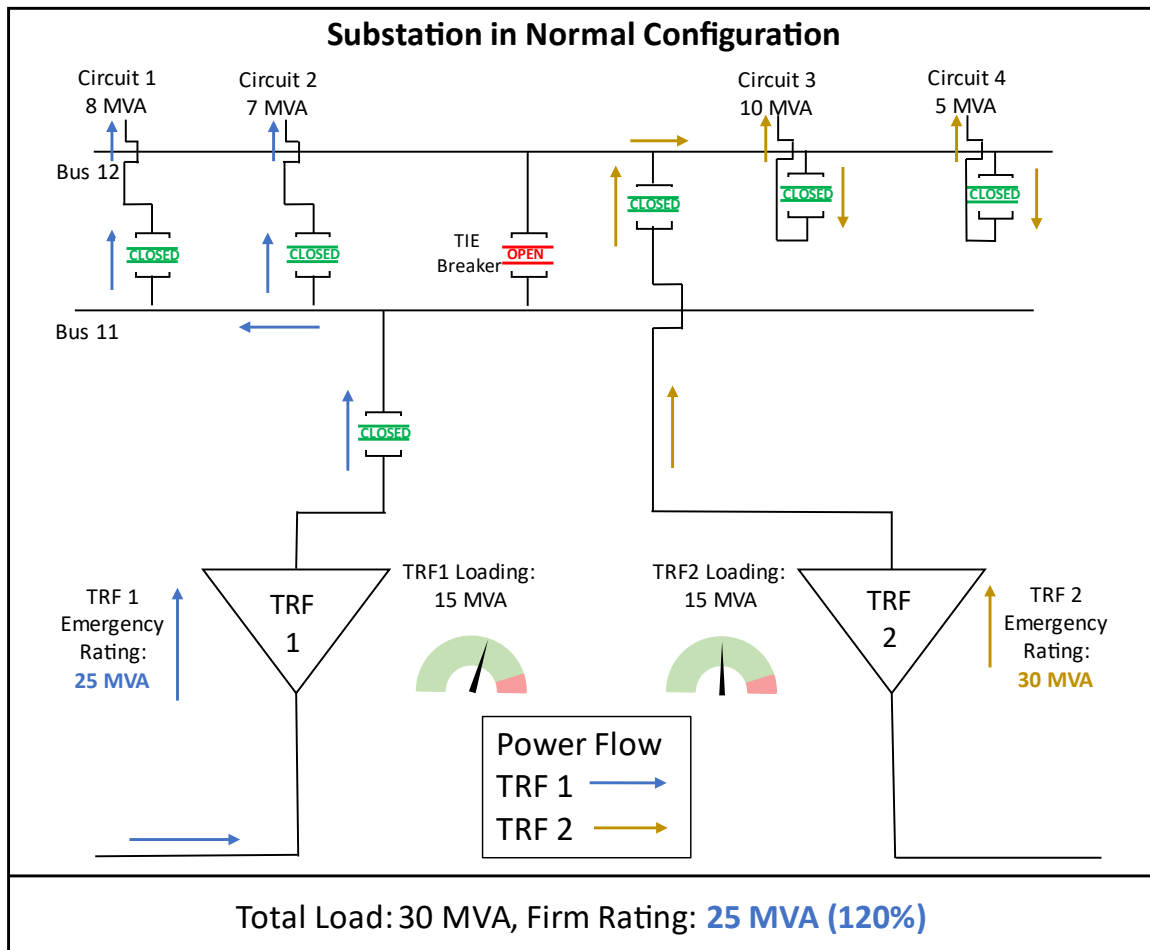
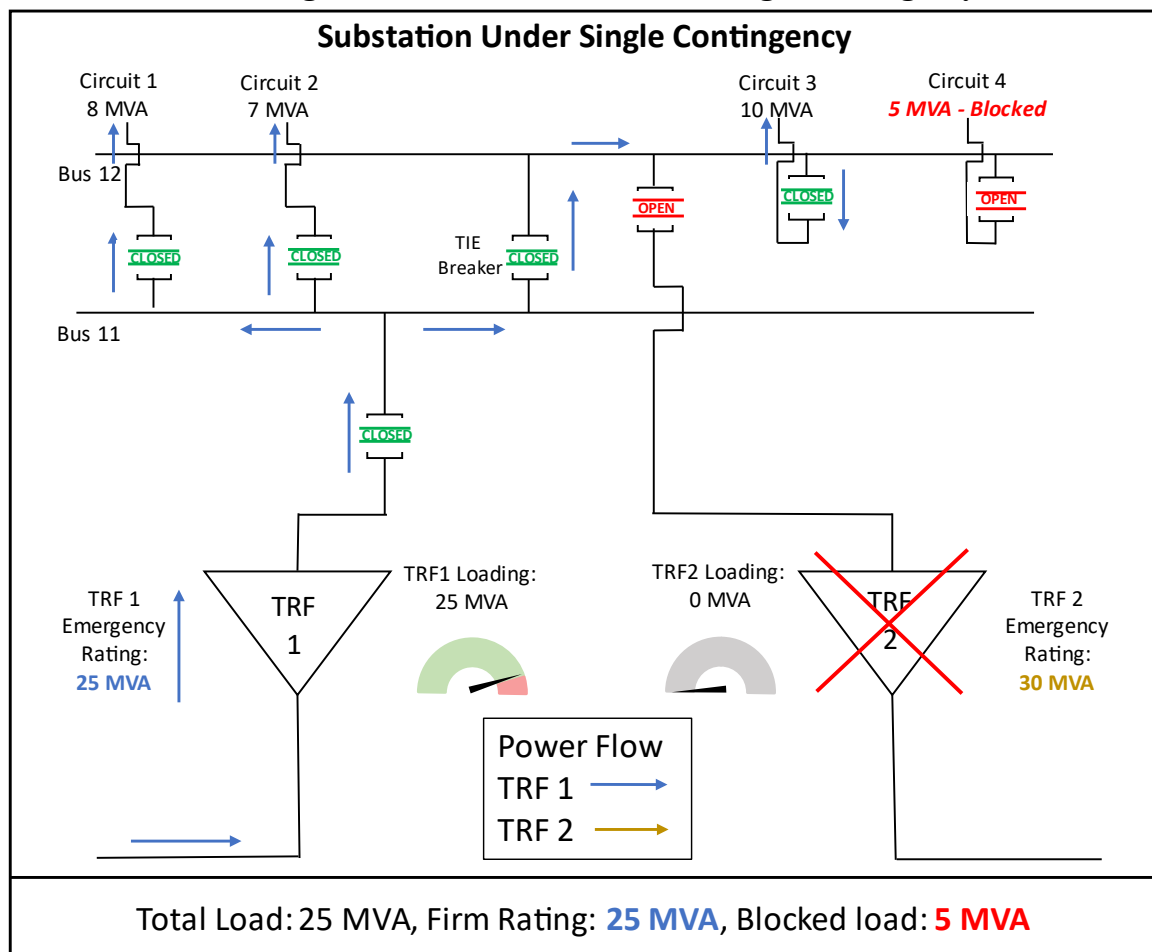


Figure 18 below shows the same substation operating in a single contingency situation where Transformer 2 is out of service. Transformer 2 breaker is opened to isolate and deenergize it. The tiebreaker is closed to allow customer load to be rerouted through Transformer 1. In this scenario, the substation was operating over firm rating, therefore only 25 MVA of the total 30 MVA can be served via

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Transformer 1. The result is the breaker for Circuit 4 is opened, blocking 5 MVA of load which could equate to about 1,000 customers being placed out of service to alleviate the substation overload. Engineering and Operations teams will evaluate options to restore service to these customers via adjacent circuits/substations, if capacity exists. Otherwise, these customers will be placed out of service until the damaged equipment is repaired/replaced or mobile equipment is deployed. Circuit 4 breaker would be closed (re-energized) if the total load at the substation goes below the firm rating of 25 MVA.

**Figure 18 Substation Under Single Contingency**



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1   **Q67. What are the challenges and issues with system overloads?**

2   A67. When equipment is operated in a system overload condition, the equipment is  
3       stressed, and useful life is reduced. Additionally, this impacts system operability  
4       by limiting jumpering abilities needed to support customer reliability during outage  
5       events. Without jumpering capabilities to adjacent circuits, outages will be  
6       sustained for longer periods of time because the failed equipment must be replaced  
7       to restore customers. Furthermore, overloaded equipment can also increase the  
8       probability of emergent failures leading to customer outages.

9  
10       Also, when there are overloads on the system, it is challenging for the Company to  
11       serve new customers and provide the ability for existing customers to expand.  
12       Therefore, in areas where system overloads exist, the absence of electrical capacity  
13       inhibits DTE Electric's ability to support economic growth in SE Michigan. This  
14       challenge is expected to increase with increasing loads brought by electrification  
15       and distributed generation as part of the clean energy transition.

16  
17   **Q68. What are the benefits of System Loading projects?**

18   A68. System Loading projects alleviate the stress on the system caused by overloads and  
19       reduce potential failures. These projects also increase capacity and reconfigure the  
20       system to eliminate projected overloads on specific pieces of equipment (overhead  
21       wire, underground cable, transformers), or at the circuit/substation level, and in  
22       some cases the added capacity allows for future projected load growth. While each  
23       project may add a different amount of new capacity supporting specific area and  
24       system needs, following completion of a system loading project, substations shall  
25       be under 100% of firm rating, and all equipment shall be under 100% of day-day

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1 rating. Capital investment projects to address these system overloads will also  
2 improve reliability and provide capacity for new and existing customers.  
3 Additionally, system loading projects help maintain/improve system operability by  
4 restoring/creating jumpering capabilities and removing aged equipment from the  
5 system.

6  
7 To demonstrate the benefits of System Loading projects, I will provide a specific  
8 example. The ‘System Loading: Grenada’ project will deliver on system loading,  
9 conversions, and automation benefits.<sup>18</sup> The first step of the project was to rebuild  
10 and convert a portion of an adjacent Prospect substation circuit to deliver improved  
11 reliability from the rebuild, but also mitigate an overload at Prospect substation  
12 which was over 100% of firm rating and exceeded 100% of its emergency rating in  
13 2018 (4.2 MVA loading vs 4.1 MVA rating). To address the circuit overloads,  
14 approximately half of a Prospect substation circuit has been transferred over to a  
15 Grenada substation circuit as of 2024 (summer loading of 2.1 MVA remains at  
16 Prospect). To support projected circuit/area needs, construction of a new Grenada  
17 substation is planned and will increase capacity by 77% versus the existing Grenada  
18 substation, providing capacity for continued growth and mitigating circuit  
19 overloads. Finally, additional planned circuit conversions and establishment of  
20 additional circuits will enable installation of loop schemes and circuit automation,  
21 none of which are possible without the capacity delivered in the system loading  
22 project. When fully implemented, the project is anticipated to deliver an 88%  
23 improvement in reliability versus three-year (2020-22) historic SAIDI for the area.

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<sup>18</sup> Case No. U-21860 Ex. A-12, Sch. B5.4 p. 13, line 108

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1 While each System Loading project is unique in current capacity and reliability  
2 issues, the benefits of the Grenada project are typical to the other System Loading  
3 projects.

4

5 **Q69. How does the Company forecast and mitigate system overloads?**

6 A69. Company engineers annually conduct Area Load Analysis (“ALA”) on all  
7 distribution circuits and substations to determine where there are and will be  
8 overloads on the system. The ALA process includes recording all actual peak  
9 loading values from the year and applying adjustments for known load additions  
10 and system modifications to generate future year projections. Corporate load  
11 forecasting models are also integrated along with the ALA results to identify areas  
12 which could become overloaded due to electrification, increased EV penetration,  
13 and economic growth/decline among other factors. Based on the 2024 ALA cycle,  
14 there are 69 substations operating at or over firm rating (12.3% of system), and 619  
15 distribution circuits operating at 95% or greater of planning criteria (18.7% of  
16 system).

17

18 **Q70. How are system loading projects prioritized?**

19 A70. Projects are evaluated and prioritized for load relief based on how they address five  
20 factors: (1) substation equipment overload, (2) circuit equipment overload, (3)  
21 substation over firm rating, (4) strong load growth, or (5) circuits over 8 MVA for  
22 13.2kV circuits and 3 MVA for 4.8kV circuits. Factors (1) and (2) cause overloads,  
23 whereas factors (4) and (5) are factors for future planning, and factor (3) represents  
24 contingency situations. Based on these variables, a priority ranking of the load  
25 relief projects is developed. More information about Load Relief criteria and

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1 prioritization can be found in Section 9.1 of the DGP (Exhibit A-23 Schedule M8  
2 sponsored by Company Witness Chiu).

3

4 **Q71. Can you identify the Company's proposed System Loading Projects presented**  
5 **in the instant case.**

6 A71. On Exhibit A-12, Schedule B5.4 page 12, lines 62 – 66 and page 13, lines 102 –  
7 116 are the proposed System Loading projects in the instant case. The Company  
8 spent \$14.2 million in the 2023 and projects to spend \$70.5 million in the historical  
9 test year.

10

11 The projects in the table below are proposed within the System Loading category  
12 with additional details within Exhibit A-23 Schedule M6.



**Table 9 System Loading Projects**

| Table 9 – System Loading Projects |                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                           |
|-----------------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Project Name                      | Drivers                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                   |
| System Loading: Carleton          | <p>This project upgrades Carleton substation to address capacity and loading concerns. Drivers for the project include the following:</p> <p><u>Capacity:</u> Carleton substation is a two circuit, two transformer 4.8kV substation and is at approximately 196% of the maximum load ability. 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 distribution design order limit for a 4.8kV circuit.</p> <p><u>Operability:</u> Limited jumpering options due to substation and circuit loading</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                    |
| System Loading: Jewell            | <p>This project will construct a new 13.2kV substation to relieve JEWEL substation and help in the decommissioning of aging 4.8kV WSHTN substation. Drivers for the project include the following:</p> <p><u>Reliability:</u> The circuits have been close to or exceeded the DTE average for SAIDI and CAIDI.</p> <p><u>Capacity:</u></p> <ul style="list-style-type: none"> <li>Jewell Substation serves seven load carrying circuits. In Summer 2024, Jewell substation was at 107% of its firm rating. Two circuits are at 99% of circuit day-to-day rating. There is an additional circuit that is at 97% of circuit day-to-day rating. Six of the circuits exceed the Distribution Design Order limit of 8 MVA for a 13.2kV circuit.</li> <li>The location of the load centers for the two circuits are located such that transferring load to adjacent circuits is not possible. There is evidence of steady growth and new business across the Jewell Substation area.</li> <li>Jewell Substation does have four spare circuit positions where new circuits can be created and existing circuits can be relieved but Jewell substation does not have enough capacity to utilize these spare positions. In addition, there are physical constraints that do not facilitate a substation expansion.</li> </ul> <p><u>Operability:</u> The closest substation to Jewell is Washington Substation but load transfers are not a possibility because it is a 40-4.8kV substation. Converting Washington substation at the current property is also not a possibility due to physical constraints. Furthermore, Washington is served from overloaded 40kV Tie 6907.</p> <p><u>Other:</u> There has been several residential developments happening on JEWEL within the past couple years. JEWEL has a lot of open land so we can expect more businesses and residential developments to come. Every circuit on JEWEL has more customers than the DTE average per circuit along with the 13.2kV average per circuit. 3 JEWEL circuits have OH miles more than the DTE and 13.2kV average per circuit.</p> |
| System Loading: Mohican           | <p>This project will convert existing Industrial Class 'T' Mohican Substation to General Purpose Class 'A' 120-13.2kV substation to provide capacity in the area. Drivers for the project include the following:</p> <p><u>Capacity:</u></p> <ul style="list-style-type: none"> <li>Cypress Substation is a 120kV-13.2kV substation and is 81% of its firm rating</li> <li>Three of the load carrying circuits exceed the Distribution Design Order limit of 8 MVA for a 13.2kV circuit.</li> <li>Load relief for Cypress by transferring approximately 4.5 MVA from circuit 1</li> <li>Load relief for Cypress by transferring approximately 8.5 MVA from circuit 2</li> <li>Magna is currently fed from temporary feed from Mohican. With the purchase of Mohican and conversion to a Class 'A' substation, Magna will be fed from the new substation.</li> <li>New business is planning new load growth of approximately 3 MVA</li> <li>New business is planning new load growth of approximately 8.5 MVA</li> </ul>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                   |
| System Loading: Brown City        | <p><u>Safety:</u> Minimize risk of energized downed wire. Breakers at MARLT 4.8kV are at high risk.</p> <p><u>Reliability:</u> TCOMA DC8311 has a 5-year SAIDI average in 3rd quartile. MARLT DC0315 and DC0316 both have 5-year SAIDI averages in 2nd quartile. MARLT DC8281 has a 5-year SAIDI average in 3rd quartile. SHAW has a 5-year SAIDI average in 4th quartile. The initiative area has a 5-year SAIDI average in 3rd quartile.</p> <p><u>Capacity:</u> MARLT 4.8kV substation is at 73% firm and MARLT 13.2kV substation is at 92% firm. BRCTY substation is at 70% firm. TCOMA substation is at 117% firm. 2025 Pre-Peak work should bring TCOMA down to 105%. SHAW substation is at 114% firm. SHAW circuit 1 is at 122% of firm. There is 1.3MVA of capacity remaining over 175 square miles of DTE service territory.</p> <p><u>Operability:</u> BRCTY substation is 4.8kV and surrounded by TCOMA substation, which is 13.2kV, leaving BRCTY with no jumpering options. ISO Downs in the area prevent OH operability between TCOMA, MARLT 13.2kV, and surrounding 13.2kV substations. Leaving TCOMA and MARLT with no jumpering options. MARLT and SHAW also have no external jumpering options</p> <p><u>Other:</u> MARLT 4.8kV substation is a Class E, an older substation class in the process of being decommissioned. MARLT 4.8kV substation has no blocking installed. If the substation exceeds Firm and experiences a subtransmission outage or transformer failure, the other transformer shall exceed its emergency rating when the automatic throwover operates. There is no room to install blocking.</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                   |
| System Loading: Chesterfield      | <p><u>Capacity:</u> Substation is approaching FIRM with Method of Service (MOS) requests and development consistently coming in. There have been 14 MOS requests since 2023 with 11 go-ahead. Some MOS required work on the distribution circuits to be able to feed customers</p> <ul style="list-style-type: none"> <li>CHEST substation is at 94% FIRM with five circuits over DDO</li> </ul>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                          |

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| Table 9 – System Loading Projects |                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                |
|-----------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Project Name                      | Drivers                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                        |
|                                   | <ul style="list-style-type: none"> <li>• CHEST DC 1 at 91% normal day-to-day rating (2024)</li> <li>• CHEST DC 2 at 94% normal day-to-day rating (2024)</li> <li>• CHEST DC 3 at 79% normal day-to-day rating (2024)</li> <li>• CHEST DC 4 at 98% normal day-to-day rating (2024)</li> <li>• CHEST DC 5 at 85% normal day-to-day rating (2024)               <ul style="list-style-type: none"> <li>- VICTR substation at 85% FIRM and VICTR DC 1 at 57% normal day-to-day rating (2023)</li> </ul> </li> <li>• There have been multiple load transfers to nearby VICTR circuits to relieve CHEST</li> <li>• 1.3 MVA load transfer on 9/2023</li> <li>• 2.2 MVA load transfer (2024 Pre-peak)</li> </ul> <p><u>Operability/Capacity:</u> TRK4911 has capacity and operability concerns with current loading at substations.</p> <p><u>Reliability:</u> Some circuits have low voltage and three circuits in the 4th Quartile (2023) for SAIDI</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                              |
| System Loading:<br>Cody           | <p>Load relief and capacity are the main drivers for this project. Other drivers for the project include the following:</p> <p><u>Safety:</u> Minimize risk of energized downed wire.</p> <p><u>Reliability:</u> CODY circuits have long OH miles (over the average/circuit) with old poles and many customers (over the average/circuit). Voltage issues exist at the ends of the circuits due to long overhead miles, small wire sizes, and high loads. Outages occur mostly in storm events.</p> <p><u>Capacity:</u> (2024 ALA): Cody (CODY) substation has two transformers and four load carrying circuits. The substation is projected to be at 98% of its firm rating. Two circuits exceed the Distribution Design Order limit. The first circuit is 74% of its day-to-day rating. Lyon Twp is a rapidly increasing in growth as it is one of the fastest growing townships in Oakland County.</p> <p><u>Operability:</u> For this substation configuration, upon the loss of a transformer, the transformer load should be able to transfer on the other transformer. Due to the high loads, that is not possible. There are little to no jumpering options outside of the substation due to overloaded circuits and ISO down pockets limiting load transfers.</p> <p><u>Other:</u> All CODY circuits have more customers than the DTE average circuit. Every CODY circuit has overhead miles larger than the DTE average &amp; the 13.2kV circuit average. Multiple residential method of services have been received in CODY territory and Lyon Twp has mentioned a couple more developments in the near future.</p> |
| System Loading:<br>Diamond        | <p>Diamond substation is a two transformer, four circuit substation and is at 131% of its firm rating. This project will upgrade one of the substation transformers at the substation. Drivers for the project include the following:</p> <p><u>Reliability:</u> 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.</p> <p><u>Capacity:</u> 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.</p> <p><u>Operability:</u> Transformer #1 was replaced during an emergency failure event in March 2019; firm rating is now limited by smaller sized Transformer #2.</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                            |
| System Loading:<br>Disco          | <p>This project will install two new circuits out of Bronco substation to relieve load at Disco substation and circuits. Drivers for the project include the following:</p> <p><u>Reliability:</u> 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.</p> <p><u>Capacity:</u> In 2022 DISCO was at 111% of FIRM and in 2023 DISCO was at 109% of FIRM. There are currently two transformers and four load carrying circuits at DISCO substation. Three out of the four circuits at DISCO are currently above the DDO rating for a 13.2kV circuit of 8MVA. There are no spare positions at DISCO to build a new circuit.</p> <p><u>Operability:</u> DISCO circuits have limited jumpering options due to neighboring circuits being overloaded. DISCO Substation cannot utilize diesel generators due to high phase imbalance on circuits. Approximately ~1.9 MVA of load had to be shed, leaving customers without power when there is a substation failure.</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                     |
| System Loading:<br>Goodison       | <p><u>Reliability:</u> GODSN SAIDI and SAIFI usually is above the DTE system average. Long Overhead Miles with limited jumpering points to transfer during an outage event.</p> <p><u>Capacity:</u> GODSN is at 124% of its firm rating . Both GODSN circuits exceed the Distribution Design Order limit of 8MVA for a 13.2kV circuit.</p> <p><u>Operability:</u> 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.</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                  |
| System Loading:<br>Grenada        | <p>Grenada substation is located in Ann Arbor. There are four substations serving the general area: Grenada, Price, Prospect and Wolverine. Drivers for the project include the following:</p> <p><u>Reliability:</u> GRENA has a 3-year average SAIDI of 1,487.</p> <p><u>Capacity:</u> Prospect and Wolverine substations are either near or exceed 100% of their firm rating. (Prospect under firm as of 2024 as project is progressing). Several circuits on these four substations exceed the</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                         |

| Table 9 – System Loading Projects    |                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                    |
|--------------------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Project Name                         | Drivers                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                            |
|                                      | <p>8MVA distribution design order standard for a 13.2kV circuit. For the loss of any one of these substations, the stranded load could range from 4% to 30% of total load. For the loss of a single transformer at any one of these four substations, the stranded load could be as high as 9% of total load.</p> <p><u>Operability:</u> 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.</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                               |
| System Loading:<br>Kings Point       | <p>This project will construct a new 13.2kV substation to provide capacity in the area. Drivers for the project include the following:</p> <p><u>Safety:</u> Minimize risk of energized downed wire.</p> <p><u>Capacity:</u> Boyne substation is a 120kV-13.2kV substation and is 114% of its firm rating. BOYNE circuit 1 is 109% of day-to-day rating and BOYNE circuit 2 is 93% of its day-to-day rating. All six of the load carrying circuits exceed the Distribution Design Order limit of 8MVA for a 13.2kV circuit. Golf Substation is a 120kV-13.2kV substation and is at 93% of its firm rating. Two circuits at Golf substation exceed their day-to-day ratings while three others exceed 90% of their day-to-day ratings. Seven of the load carrying circuits exceed the Distribution Design Order limit of 8MVA for a 13.2kV circuit. Nearby Omega substation is a 40kV-13.2kV substation which exceeds its blocking limit. The loss of either transformer at Omega substation results in 5.8MVA of stranded load. The subtransmission lines are overloaded in the area. The current infrastructure is unable to support new load growth in the area.</p> <p><u>Operability:</u> Omega and surrounding substations high loading limits jumpering options.</p>                                                                                                                                                                                                                                                         |
| System Loading:<br>Lark/Spruce       | <p>This project constructs a new 13.2kV substation with two new circuits to relieve Spruce substation and reconfigure Spruce circuits. Drivers for this project include the following:</p> <p><u>Safety:</u> Minimize risk of energized downed wires.</p> <p><u>Reliability:</u> 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, there is an opportunity to remove/reconfigure these trouble sections with the construction of a new substation.</p> <p><u>Capacity:</u> Spruce substation is at 109% of 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, which limits new business and EV adoption.</p> <p><u>Operability:</u> Spruce circuits have areas that are 13.2kV islands (surrounded by only 4.8kV) which has led to limited jumpering points and little opportunity for load transfers.</p>                                                                                                                                                                                                                                                                                                                                             |
| System Loading:<br>Otsego/Capac/Shaw | <p>Drivers for this initiative includes the following:</p> <p><u>Reliability:</u> CAPAC average SAIFI from 2019 to 2023 is 2.7 and average CAIDI from 2019 to 2023 is 380.15 OTSGO average SAIFI from 2019 to 2023 is 2.0 and average CAIDI from 2019 to 2023 is 367.24</p> <p><u>Capacity:</u> OTSGO Substation is 120% of the firm rating. CAPAC Substation is at 109% of Firm. OTSGO circuit 1, circuit 2, and CAPAC circuit 1 exceed the Distribution Design Order limit of 8MVA for a 13.2kV circuit</p> <p><u>Operability:</u> OTSGO and CAPAC both have LTBT blocking installed which would block the automatic throwover at the substation if it would cause an overload. This could cause stranded load.</p> <p><u>Other:</u> 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</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                            |
| System Loading:<br>Port Sanilac      | <p><u>Safety:</u> Minimize risk of energized downed wire</p> <p><u>Reliability:</u> PTSAN and FOSTR circuits have been in 4th quartile SAIDI and SAIFI for several years showing poor reliability. Forester has aged Line Section Breaker (L.S.B.) in need of replacement. Installed in 1988 and the only 40kV LSB on the DTE system, there are no replacements available. 3-333kVA pole mount transformers at Forester are also at-risk equipment. The circuits at Port Sanilac are limited by substation regulators that are considered at-risk with no spare parts available.</p> <p><u>Capacity:</u> Forester substation is a Class T substation with a single circuit. The substation is 103% of its firm rating and the circuit is at 103% of its day-to-day rating. Port Sanilac is a Class T, 4.8kV substation with two circuits. The substation is 83% of its firm rating with both circuits approaching 90% of their day-to-day rating.</p> <p><u>Operability:</u> The area surrounding Port Sanilac hasn't seen significant load growth in recent years, but the loading on it and surrounding substations has increased to a point at which new loading cannot be adequately served. There are 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.</p> <p><u>Other:</u> TIE 4105 rebuild cost saving by not having to extend conductor to PTSAN site when decommissioned.</p> |
| System Loading:<br>Richmond/Armada   | <p>This project will construct a new 13.2kV substation and decommission two aging 4.8kV substations. Drivers for the project include the following:</p> <p><u>Safety:</u> Minimize risk of energized downed wire</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                               |

| Table 9 – System Loading Projects |                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                    |
|-----------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Project Name                      | Drivers                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                            |
|                                   | <p><u>Reliability:</u> 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.</p> <p><u>Capacity:</u> Richmond 4.8kV substation is 96% of its firm rating. RICHM DC 6 is at 83% of its day-to-day rating. Both RICHM DC 6 and RICHM DC 5 exceed the Distribution Design Order limit of 3MVA for a 4.8kV circuit. Armada substation is adjacent to Richmond substation. The 4.8kV portion of the Armada substation is 112% of its firm rating and ARMAD DC2 is 112% of its day-to-day rating. The 13.2kV side of Armada substation is 80% of its firm rating and its transformer is 80% of its day-to-day rating. The substation's 5-year average (2018-2022) has been 98% of its firm rating and ARMAD DC50 has been over the DDO limit of 8MVA.</p> <p><u>Operability:</u> Armada has limited jumpering options so when the substation needs maintenance, a portable substation is required to pick up the load.</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                              |
| System Loading: Spokane/Seneca    | <p>This project addresses loading and capacity concerns at Spokane and Seneca substations by expanding Spokane substation. Drivers for the project include the following:</p> <p><u>Safety:</u> 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.</p> <p><u>Capacity:</u> Spokane substation is a 120-13.2kV substation with seven (7) load carrying circuits. Based on 2024 peaks, the substation is at 114% of its firm rating. Four (4) circuits exceed the Distribution Design Order limit of 8 MVA for a 13.2kV circuit. Spokane Substation is surrounded by overloaded Seneca and Tienken substations. Seneca is a 120-13.2kV substation. It is a walled substation and does not have the footprint to accommodate an expansion. Based on 2024 peaks, the substation is 118% of its firm ratings and two (2) out of six (6) circuits exceed the Distribution Design Order limit of 8 MVA for a 13.2kV circuit. Tienken is a 120-13.2kV walled substation which is at 97% of its firm rating. One circuit is over its day-to-day rating and exceeds the Distribution Design Order limit of 8 MVA for a 13.2kV circuit. There is a project already in place to relieve this substation.</p> <p><u>Operability:</u> Limited jumpering options outside of Spokane substation.</p> <p><u>Other:</u> DTE's Equipment Performance and Protective Maintenance group recommends the replacement of the current 11-position switchgear, as it is at risk of failure.</p> |
| System Loading: Sterling          | <p>This project will address capacity and loading concerns at Sterling substation by expanding the substation. Drivers for the project include the following:</p> <p><u>Capacity:</u> Sterling Substation serves nine load carrying circuits. In Summer 2023, one (1) Distribution Circuit was at 97% of its normal day-to-day limit. Three circuits exceed the Distribution Design Order limit of 8MVA for a 13.2kV circuit. 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.</p> <p><u>Operability:</u> Load cannot be transferred or jumpered to adjacent circuits without causing loading issues on those circuits. Lack of jumpering points within Sterling circuits</p> <p><u>Reliability:</u> Sterling circuits have on average 400 minutes of interruption per year. Sterling circuits are close or above DTE system SAIDI for the past 5 years.</p> <p><u>Other:</u> 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.</p>                                                                                                                                                                                                                                                                                                                                                        |
| System Loading: Wixom             | <p>This project will expand Wixom substation to address loading and capacity concerns. Drivers for this project include the following:</p> <p><u>Safety:</u> 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.</p> <p><u>Reliability:</u> SAIDI fluctuates year after year for WIXOM circuits and a few circuits exceed DTE system average.</p> <p><u>Capacity (2024 ALA):</u> WIXOM is at 101% of firm. 6 of 7 WIXOM circuits are over the 8MVA DDO. The 7th circuit is right below the 8MVA DDO. 4 of 7 circuits are above nominal cable DD ratings. Multiple MOSs have been received. 4.8MVA of new load has been committed and multiple MOSs are waiting for customer signatures.</p> <p><u>Operability:</u> 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.</p> <p><u>Other:</u> Receiving multiple method of services (customer load requests). WIXOM cannot support industrial customers due to existing circuit loadings.</p>                                                                                                                                                                                                                                                                                                                      |

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1 **VII. Subtransmission Redesign & Rebuild Program**

2 **Q72. Can you describe the Company's Subtransmission system?**

3 A72. The Company's Subtransmission system is an interconnected web that distributes  
4 subtransmission level voltage across the service territory to stations, a critical link  
5 between the external transmission system (owned by the unaffiliated International  
6 Transmission Company ("ITC")) and the Company's distribution system. The  
7 equipment at these stations steps down the voltage to distribution levels to serve  
8 customers. The subtransmission system, operated at the voltages of 24kV, 40kV,  
9 and 120kV, provides a vital service as each subtransmission circuit serves one or  
10 more distribution substations, supporting anywhere from 1 to 14,600 customers.

11

12 The oldest part of the Company's subtransmission system operates at 24kV and is  
13 primarily underground, supplying power to 4.8kV distribution substations in key  
14 areas like Detroit, Monroe, and Port Huron. As noted in the CODI Conversion  
15 Program section of my testimony, this system includes some of the oldest cables in  
16 the network. Due to its age and increasing failures, Company engineers developed  
17 a plan to decommission the 24kV subtransmission system in conjunction with the  
18 4.8kV Conversions Programs.

19

20 The main subtransmission voltage in the Company's system is 40kV. This system,  
21 a mix of overhead and underground circuits, was developed as populations began  
22 moving from major cities to the suburbs. The Company also uses limited 120kV  
23 elements, primarily to connect the Company's stations and substations to ITC's  
24 120kV system.

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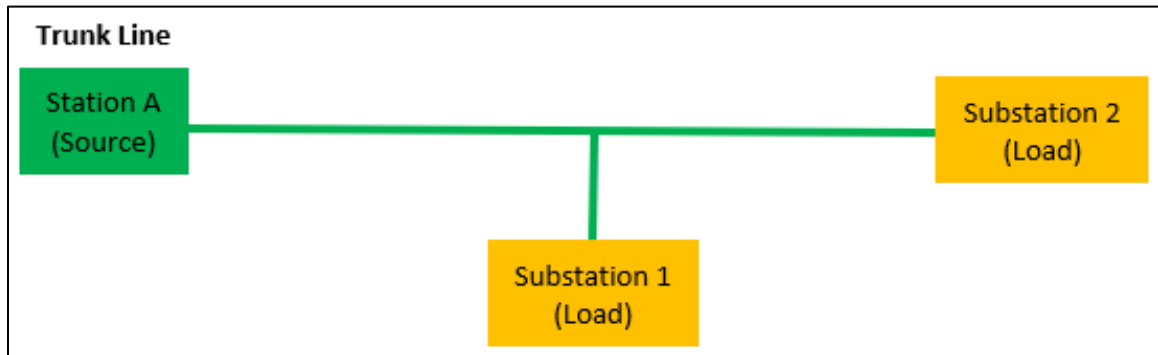
1 Because of its critical role in the grid, the subtransmission system is designed to  
2 provide redundancy and greater reliability to the feed points of the distribution  
3 system. Redundancy is necessary to provide continued service to the customers  
4 during a single contingency situation; I defined contingency situations earlier in my  
5 testimony.

6  
7 The Company's subtransmission system includes both radial and network designs.  
8 The radial configuration, called a trunk line as shown in Figure 19, has one source  
9 station which then feeds one or multiple substations. The network configuration,  
10 called a tie line as shown in Figure 20, has multiple source stations which feed one  
11 or multiple substations.

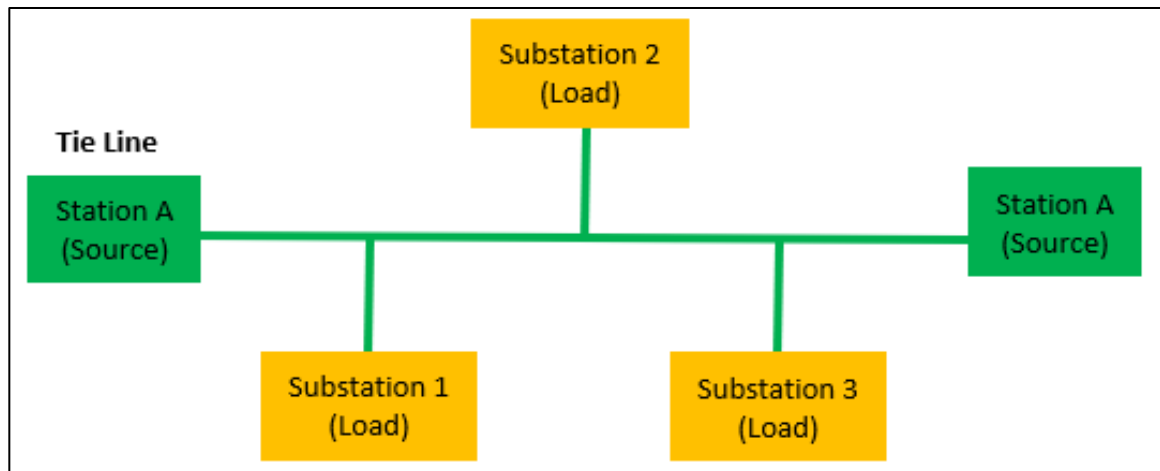
12  
13 To support reliability in the event of a fault or equipment failure on the  
14 subtransmission system, the Company utilizes a coordinated system of automatic  
15 pole top switches ("APTS") and line section breakers on the networked tie lines to  
16 isolate faults and maintain service to customers during single contingency failure  
17 situations.

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1

**Figure 19 Subtransmission Trunk Line Configuration**

2

**Figure 20 Subtransmission Tie Line Configuration**

3

4 Q73. What type of analysis is performed to ensure adequate capacity in the  
5 subtransmission system?

6 A73. Similar to the ALA I mentioned earlier for distribution circuits, Subtransmission  
7 Planning engineers analyze the condition of the system annually to determine any  
8 existing or potential limitations to having adequate capacity to support customers  
9 in a single contingency situation. This analysis is conducted by utilizing industry-  
10 standard modeling software ("PSSE & TARA"), using both individual substation  
11 loads, and electric models provided by the Midcontinent Independent System  
12 Operator ("MISO").

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1 The electric models provided by MISO include multiple system loading scenarios,  
2 including current and projected future peak loading conditions. Using these  
3 models, Company engineers run a study on each individual subtransmission trunk  
4 or tie line, with potential contingency situations assessed to identify all violations  
5 of subtransmission planning criteria. The planning criteria focuses on both thermal  
6 overloads and voltage violations under normal system conditions and during a  
7 single contingency configuration at peak system load. Similar methodology and  
8 guidelines are used by other utilities when analyzing their systems.

9

10 **Q74. What is a subtransmission planning criteria thermal violation?**

11 A74. Thermal violations, a subset of planning criteria violations, occur when analysis  
12 indicates that subtransmission equipment overloads, which are a result of consistent  
13 and general load growth over time, will likely lead to the overheating of equipment,  
14 resulting in permanent damage or failure of the equipment. For example,  
15 overloading an underground cable degrades its insulation properties leading to  
16 catastrophic failure over time.

17

18 For system day-to-day normal operating conditions, the subtransmission equipment  
19 can be loaded up to 100% of its normal rating without damaging equipment or  
20 causing outages to customers. When the subtransmission circuit/equipment is  
21 loaded above 100%, it's considered a thermal violation, resulting in the overheating  
22 of and resultant damage to equipment, which is often cumulative over time.

23

24 For example, referring to the 2019 annual system review, the subtransmission trunk  
25 line TRK4217 has a normal rating of 19 MVA, yet it currently serves 23.4 MVA



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1 of load under normal operating conditions, meaning this cable is loaded to 123% of  
2 its day-to-day rating. This day-to-day over capacity condition is leading to the  
3 accelerated degradation of cable life. Additionally, when the load peaks above the  
4 day-to-day normal rating, as can occur on a hot summer day, there is further  
5 increase in the probability of failure. In this example, that failure would impact  
6 approximately 4,600 customers, and potentially for an extended amount of time,  
7 dependent on mode of failure, time to locate, and resource availability. To address  
8 these high impact overload scenarios, the Company identified and developed  
9 projects to address all day-to-day over capacity conditions.

10

11 For emergency conditions, which is defined as when a single contingency event  
12 occurs for a limited time, the subtransmission equipment can be loaded to 90% of  
13 its emergency rating. Per the company's internal guidelines, the equipment  
14 emergency ratings are higher as the equipment can withstand additional load during  
15 short periods of time. When equipment exceeds 90% of its emergency rating, load  
16 shed (i.e. intentional customer outages) must be initiated to protect the equipment  
17 from failure due to thermal loading and overheating.

18

19 For example, the subtransmission trunk line TRK3509 has an emergency rating of  
20 32.8 MVA. During a single contingency event, such as loss of TRK3536,  
21 TRK3509 will have to carry 35.8 MVA, resulting in TRK3509's cable being loaded  
22 to 109% of its emergency rating. A failure of this cable could impact approximately  
23 14,800 customers for an extended period of time dependent on the mode of failure,

Line  
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1 time to locate, and resource availability. The TRK3509 project will address this  
2 thermal overload condition.<sup>19</sup>

3  
4 In a typical case where two subtransmission lines are feeding a distribution  
5 substation and one of them is interrupted due to a failure or outage event, the second  
6 subtransmission line can only serve load that is up to 90% of its emergency rating  
7 on a temporary basis while the first line is being restored. If the combined load of  
8 the distribution substations exceeds 90% of the emergency rating of the remaining  
9 subtransmission circuit, load will be intentionally interrupted resulting in customer  
10 outages to prevent equipment damage and additional larger cascading outages.

11

12 **Q75. Can you detail an example where a thermal violation impacted system**  
13 **Redundancy?**

14 A75. Yes, the Trunk 0359 example below demonstrates a thermal violation where the  
15 Company had to shed load, putting customers out of power until mobile equipment  
16 was deployed.

17

18 During normal operations, as shown in Figure 21, Trunk 0359 feeds distribution  
19 substation transformer 2 and Trunk 4338 feeds distribution substation transformer  
20 1. As described in Figure 22, on September 4, 2023, there was a cable failure on  
21 Trunk 4338 (shown in blue in Figure 22), which serves distribution substation  
22 transformer 1. The load normally served from distribution substation transformer 1  
23 was automatically transferred to distribution substation transformer 2, which is  
24 served from Trunk 0359 (shown in green in Figure 22). Trunk 0359 then exceeded

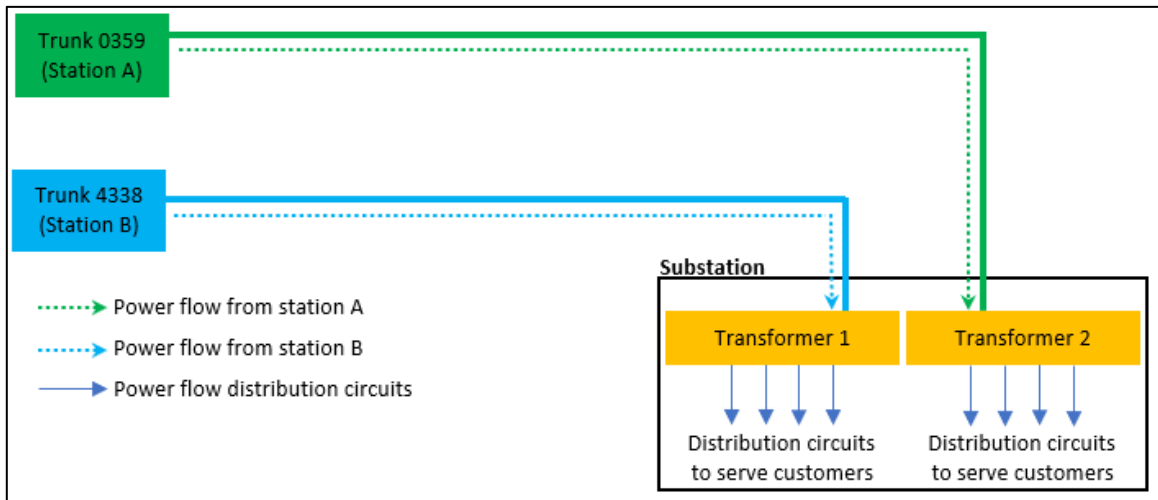
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<sup>19</sup> Case No. U-21860 Ex. A-12 Sch. B5.4, p. 11, line 28

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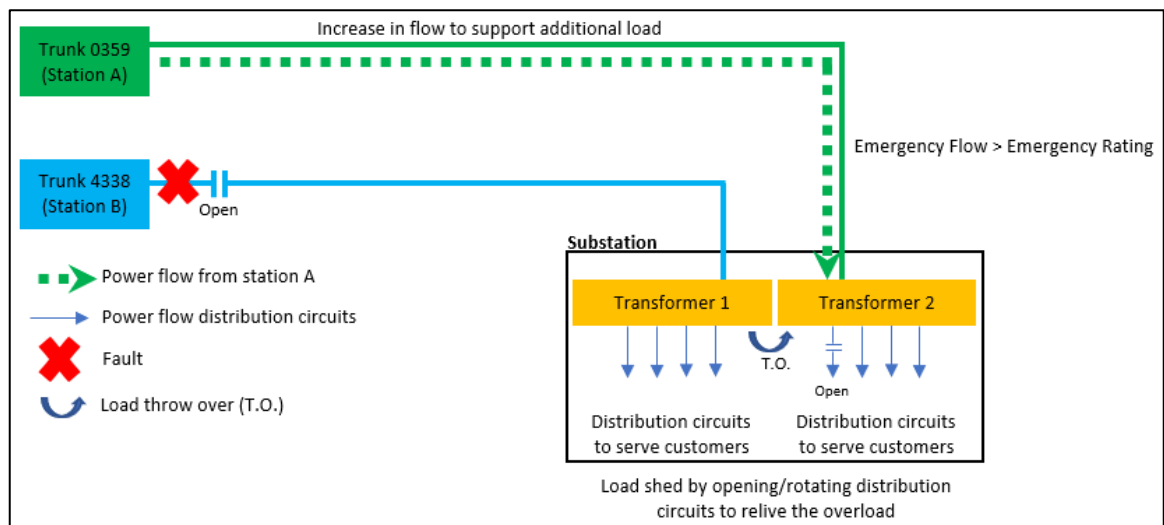
1 its emergency rating while it carried all the load of the distribution substation  
2 (transformers 1 and 2). As a result, all the circuits out of the distribution substation  
3 were rotated through outages (load shed) by the System Operator, until five large  
4 portable generators were delivered and installed to relieve load on September 6,  
5 2023. A photograph of a representative example of a large portable generator and  
6 street placement is included as Figure 23 below. Final repairs were completed on  
7 September 16, 2023, and the circuits were then returned to their normal state.

**Figure 21 Trunk 0359 & Trunk 4338 - Normal State**



2

**Figure 22 Trunk 0359 & Trunk 4338 - Emergency State Situation**



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1

2

**Figure 23      Representative Example Portable Generator Utilized on  
TRK0359**

3

4

5

6

7

8

9

As shown in Table 10, this event resulted in over 5,000 customers experiencing over 1.5 million customer minutes interrupted for approximately two days, until portable generators could be installed, preventing a more extended outage. The Company subsequently developed a project to replace the cable of Trunk 0359 to increase the circuit rating and prevent future load shedding for this single contingency event (i.e. the loss of Trunk 4338).

10

11

**Table 10    Distribution Substation Outages from September 4, 2023**

| <b>Summary of Load Shed between 9/4/2023 &amp; 9/6/2023 to Prevent Overload on TRK0359</b> |                        |                                                      |                                                               |
|--------------------------------------------------------------------------------------------|------------------------|------------------------------------------------------|---------------------------------------------------------------|
| <b>Circuit</b>                                                                             | <b>Total Customers</b> | <b>Outage Duration (minutes)</b>                     | <b>Total Customer Minutes between 9/4/2023 &amp; 9/6/2023</b> |
| <b>DC 1</b>                                                                                | 860                    | 382                                                  | 328,520                                                       |
| <b>DC 2</b>                                                                                | 582                    | 248                                                  | 144,336                                                       |
| <b>DC 3</b>                                                                                | 1106                   | 210                                                  | 232,260                                                       |
| <b>DC 4</b>                                                                                | 538                    | 536                                                  | 288,368                                                       |
| <b>DC 5</b>                                                                                | 610                    | 496                                                  | 302,560                                                       |
| <b>DC 6</b>                                                                                | 870                    | 280                                                  | 243,600                                                       |
| <b>DC 7</b>                                                                                | 629                    | 42                                                   | 26,418                                                        |
| <b>Total Customers Impacted: 5195</b>                                                      |                        | <b>Total Customer Minutes Interrupted: 1,566,062</b> |                                                               |

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1 This event is just one example of the conditions that exist on the subtransmission  
2 system, highlighting that redundancy and planning to mitigate single contingency  
3 scenarios and the corresponding Subtransmission Redesign & Rebuild Program  
4 projects are critical to maintaining reliable service for our customers.

5

6 **Q76. What is a subtransmission planning criteria voltage violation?**

7 A76. A voltage violation is another sub-category of planning criteria violations. This  
8 occurs when subtransmission system conditions lead to a voltage level that is  
9 outside of +/- 5% of the intended nominal system voltage, as is required by the  
10 ANSI C84.1 standard. Per this criterion, a 40kV subtransmission circuit needs to  
11 maintain the system voltage between 38kV (95%) and 42kV (105%). If the system  
12 voltage falls outside of this required range, the customers' equipment (*e.g.*, washer,  
13 dryer, refrigerator, water heater, furnace, garage door opener, and dim/bright lights)  
14 will not function properly and may cause damage operating at these levels. Thus,  
15 when the subtransmission circuit voltage falls outside of this required range, it is a  
16 violation of the voltage planning criteria under normal operations.

17

18 Under emergency contingency conditions, where a subtransmission circuit has to  
19 carry additional load, the Company does allow subtransmission circuits to be  
20 operated as low as 92% of nominal voltage for a short period of time to prevent  
21 outages to customers. The Company's voltage violation criteria under emergency  
22 single contingency conditions is 92% to 105% of the nominal voltage.

23

24 Voltage violations commonly occur when loading on the system has increased. This  
25 could happen during normal operation, such as when load growth from new homes

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1 and businesses moves into an area and connects to the electric grid, increasing the  
2 area's electric demand. The voltage violation could also occur in a contingency  
3 state when load has been increased on portions of the system due to temporary load  
4 transfers that occur to keep customers energized in the event of equipment failure.

5

6 **Q77. Can you detail an example where a voltage violation could impact system**  
7 **redundancy?**

8 A77. Yes, the northeast area transformer project example below demonstrates how a  
9 voltage violation could impact system redundancy.

10

11 The northeast area transformer is a critical piece of equipment to serve load for the  
12 northeast region of DTE Electric's service territory. If an outage were to occur on  
13 the northeast area transformer or its associated equipment, there are 29 substations  
14 affecting approximately 37,000 customers, that will have voltage below 92% of  
15 nominal voltage, thus creating the emergency voltage violation condition. In this  
16 emergency voltage violation condition, the Company would be forced to shed load  
17 to protect its and customers' equipment until voltage can be restored to the  
18 Company's minimum criteria of 92%. To resolve this planning criteria violation, a  
19 project is underway to install a second 120-40kV transformer at the northeast area  
20 station to provide redundancy for this critical source.

21

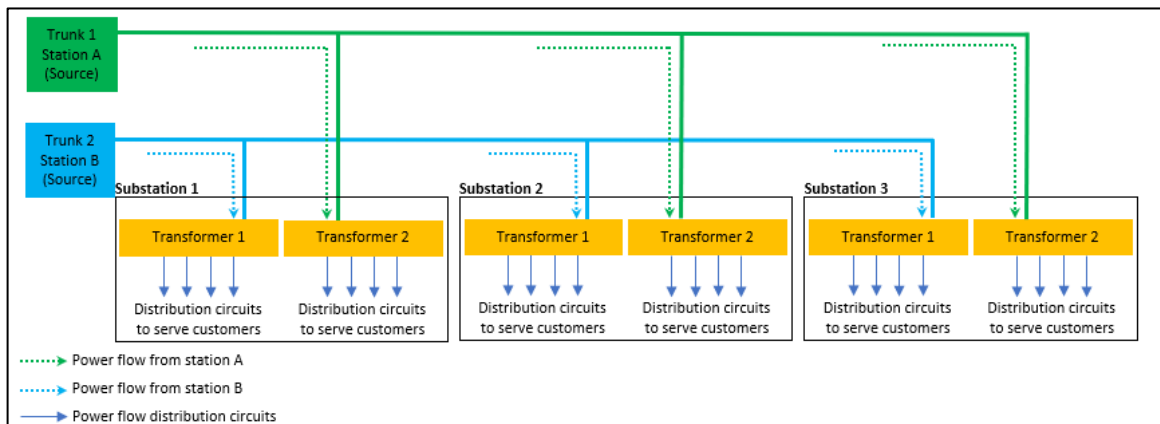
22 **Q78. Why does the Company plan to a single contingency scenario for the**  
23 **subtransmission system?**

24 A78. Consistent with the standard industry planning approach, the Company plans to a  
25 single contingency scenario to provide continued service to larger numbers of

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customers in a subtransmission outage event. For example, Figures 24 and 25 show a high-level trunk line configuration in both a normal and single contingency scenario, respectively. In a normal configuration, two different trunk lines (Trunk 1 and Trunk 2) feed the multiple substations. Substations 1, 2, and 3 load will be split between the two subtransmission circuits (Trunk 1 and Trunk 2), as shown in Figure 24. When one of the subtransmission circuits (Trunk 1) experiences an outage (*i.e.*, a single contingency), the second subtransmission circuit (Trunk 2) will have to carry all the load served by substations 1, 2, and 3 to prevent an extended outage, as shown in Figure 25. If this redundancy is not available, the result is potentially a long duration outage that requires the deployment of costly mobile generation or portable substations to restore customers.

**Figure 24 Subtransmission Normal Trunk Line Configuration**



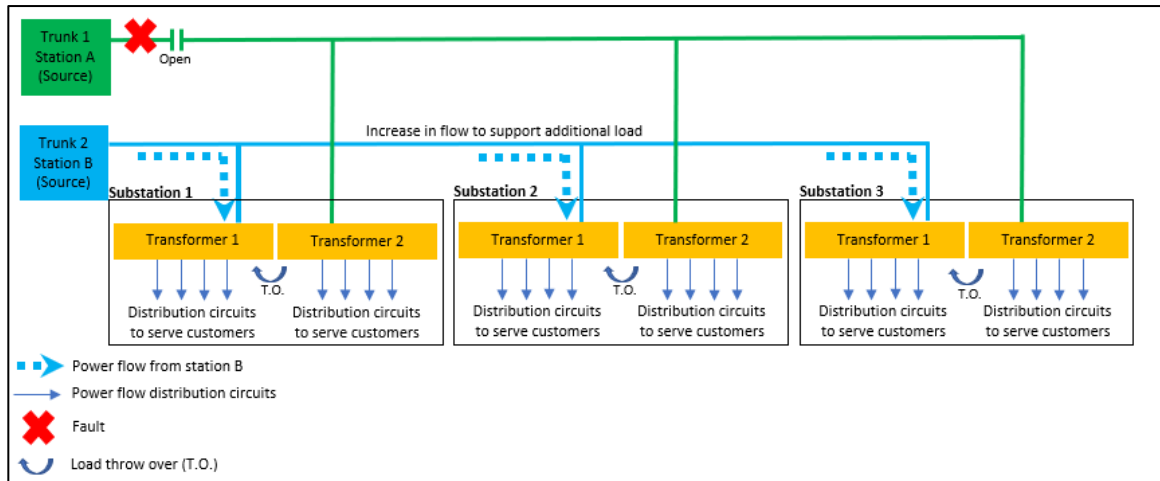


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**Figure 25 Subtransmission Single Contingency Trunk Line Configuration**



3

4 **Q79. What is the current condition of the Company's subtransmission system?**

5 A79. Similar to the distribution system, the subtransmission system is experiencing  
 6 aging, beyond 80 years old in some areas, and storm related resiliency challenges,  
 7 as well as increased loading in some areas, leading to loss of redundancy.  
 8 Additionally, some areas of the subtransmission overhead system are in difficult-  
 9 to-access, deeply wooded areas and along railroads, increasing the time and  
 10 difficulty for restoring service or maintaining equipment. These factors have led to  
 11 an increased number of failures on both the overhead and underground  
 12 subtransmission systems and lengthy restorations. Because of the essential role of  
 13 subtransmission in powering and connecting substations in the larger grid, these  
 14 failures can often result in much larger sustained outages, as well as create system  
 15 risk through the loss of redundancy. An outage event on the distribution system,  
 16 downstream in the grid from the subtransmission system, can typically impact up  
 17 to ~1,000 customers, depending on the size of the circuit. By comparison, an outage  
 18 on the subtransmission system, because it is upstream in the grid, can impact

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1 multiple substations, which in some areas can result in more than 10,000 customers  
2 impacted.

3

4 Capacity analysis of the subtransmission system is performed annually, where  
5 actual and forecasted loading is compared to a standard or target state, as discussed  
6 above. Per the Company's 2023 annual subtransmission system analysis,  
7 approximately 16% of the subtransmission circuits (~ 27% of circuit line miles) on  
8 the subtransmission system violated the Company's planning criteria. These  
9 violations have been/will be analyzed by the engineering team, and projects to  
10 resolve the capacity constraints have been/will be developed.

11

12 In addition to current performance challenges impacting customer reliability, the  
13 2023 analysis showed that the Company's aging subtransmission system overall is  
14 not adequate to serve short and longer-term needs, given its limited capacity and  
15 reliability performance. In some areas of the grid, loads have increased over time  
16 and lengthened customer outages by reducing the redundancy that is essential for  
17 continued reliability as well as operability of the subtransmission system. Existing  
18 overloads and the aging equipment place loading constraints on the system. These  
19 constraints limit the Company's ability to plan for the shutdowns required for  
20 system upgrade projects and routine maintenance to only during periods of lower  
21 loading or through the deployment of portable equipment. These periods of lower  
22 loading are typically only during a few weeks in the spring and the fall season. The  
23 loading constraints also make it challenging to add new customers or provide  
24 additional capacity for existing customers when they increase the load.

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1 To address the identified planning criteria violations and reliability performance  
2 concerns with the Company's subtransmission system, the Company developed the  
3 Subtransmission Redesign & Rebuild Program.

4

5 **Q80. What is the overall scope of the Subtransmission Redesign & Rebuild**  
6 **program?**

7 A80. The Subtransmission Redesign & Rebuild Program is focused on improving grid  
8 reliability by installing new station equipment, as well as rebuilding both the  
9 overhead and underground portions of the subtransmission system. The station  
10 work involves the installation of larger new transformers, capacitor banks and  
11 associated equipment, which provides significant improvements to the system with  
12 additional capacity, redundancy, and voltage support. The overhead work will be  
13 constructed to updated, more resilient standards which include the replacement of  
14 aged wood poles with new steel poles, replacement of porcelain insulators with  
15 polymer clamp top insulators, and replacement of smaller and aging conductors  
16 with larger wires. Similar to overhead construction, the underground work consists  
17 of replacing at-risk or overloaded cable with new sections and rebuilding cable  
18 poles to new standards, supporting greater reliability for both the underground  
19 cables themselves, as well as preventing cable failure impacts to adjacent cables in  
20 the same underground section of the system.

21

22 **Q81. Did the Commission provide feedback on the Company's Subtransmission**  
23 **Redesign & Rebuild Program in Case No. U-21534?**

24 A81. Yes, the Commission noted that because the projects in the Subtransmission  
25 Redesign & Rebuild Program come with "significant costs," "going forward, a

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1 greater level of detail and quantifiable support is needed from DTE Electric to  
2 support its subtransmission projects.”<sup>20</sup> The Commission also noted that one way  
3 to provide this greater level of support is “project-specific risk-informed cost-  
4 benefit and alternative analyses for all Subtransmission projects over \$10 million,  
5 before investing substantial capital [\$1 million] beyond the conceptual and design  
6 phases.”<sup>21</sup> Further, the Commission noted that it “expects that the findings of [the  
7 Audit Report] will inform future subtransmission investments.”<sup>22</sup>

8

9 **Q82. What actions will the Company undertake to further support and quantify the**  
10 **need for the Subtransmission Redesign & Rebuild Program projects?**

11 A82. The Company will develop a comprehensive subtransmission BCA framework  
12 designed to evaluate new subtransmission projects. The Company plans to  
13 complete the framework before the next rate case filing and will apply the  
14 framework to all new subtransmission projects over \$10M. Existing  
15 Subtransmission Redesign & Rebuild Program project investments that were  
16 authorized by the Commission in Case No. U-21534 and are in progress are  
17 assumed to have already met the appropriate burden of proof since the Commission  
18 has granted approval for these projects.

19

20 **Q83. Why are “project-specific risk-informed cost-benefit and alternative analyses”**  
21 **for new Subtransmission projects not included in this rate case?**<sup>23</sup>

22 A83. Benefit Cost Analysis (BCA) for subtransmission is particularly complicated due  
23 to the networked nature of the subtransmission grid. Benefits such as load relief,

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<sup>20</sup> Case No. U-21534 - Commission Order, January 23, 2025, p.133.

<sup>21</sup> Case No. U-21534 - Commission Order, January 23, 2025, p.133.

<sup>22</sup> Case No. U-21534 - Commission Order, January 23, 2025, p.133.

<sup>23</sup> Case No. U-21534 - Commission Order, January 23, 2025, p.133.

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1 planning criteria violations, and reliability improvements are much harder to  
2 quantify compared to the distribution system. Building a BCA framework that can  
3 identify and capture these benefits will take a significant amount of time, expertise,  
4 and effort. It is not a task that could be accomplished with any degree of quality or  
5 accuracy within the window between when the Company received the Case No. U-  
6 21534 January 23, 2025 Order and the filing of the instant case.

7

8 **Q84. What did the Audit Report say about the Company's Subtransmission**  
9 **Redesign & Rebuild Program investments?**

10 A84. The Audit Report suggested the Company "[i]solate and provide Subtransmission  
11 Redesign and Rebuild Investments for those required for capacity reasons and 4.8k  
12 Conversion."<sup>24</sup>

13

14 **Q85. Does the Company agree with the Audit Report's recommendation?**

15 A85. In part, yes. As shown in Table 11, the majority of near- and long-term projects in  
16 the Subtransmission Redesign & Rebuild Program are driven by overload and  
17 capacity needs due to thermal and voltage planning criteria violations. However,  
18 there are four projects that are driven by customer reliability and a few driven by  
19 other factors.<sup>25</sup> The Company notes that while the overload and capacity projects  
20 are necessary to serve existing and new customers, the reliability projects are also  
21 a reasonable and prudent Company priority when they impact transmission  
22 reliability or are in historically poor performing areas of the subtransmission  
23 system.

---

<sup>24</sup> Audit Report, Part 2, at 84.

<sup>25</sup> "Other" drivers in Table 11 can include, but are not limited to, specific customer requests, decommissioning projects, implementation of clean generation, or projects to enhance operational performance

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1 Other projects like the high-side protection initiative are essential for enhancing  
2 customer reliability and are supported by ITC. This project involves installing  
3 switchers between the Company's transformer and the ITC 120kV bus or feed.  
4 These devices prevent downstream faults in the DTE Electric system from affecting  
5 ITC's equipment, thereby avoiding larger outages.

6  
7 Furthermore, the Company needs to address poor performing subtransmission  
8 circuits in order to improve customer reliability and reduce repetitive outages. On  
9 sections of circuits where the Company has performed tree trim and pole top  
10 maintenance and the subtransmission circuit performance still does not improve or  
11 where conductor falls due to the corroded steel core of 3/0 ACSR, these issues must  
12 be addressed; I detail an example of a failed steel core on 3/0 ACSR conductor due  
13 to corrosion on Tie 4105 below.

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**Table 11 Subtransmission Redesign & Rebuild Project Drivers**

| Project Name                                                                 | Planning<br>Criteria<br>Thermal<br>Violation | Planning<br>Criteria<br>Voltage<br>Violation | Reliability | Safety | Other |
|------------------------------------------------------------------------------|----------------------------------------------|----------------------------------------------|-------------|--------|-------|
| Ann Arbor System Improvements                                                |                                              |                                              | X           |        |       |
| Subtransmission Redesign & Rebuild: Transformer High Side Protection Program |                                              |                                              |             |        | X     |
| Subtransmission Redesign & Rebuild: Maxwell Amherst                          |                                              |                                              |             |        | X     |
| Subtransmission Redesign & Rebuild: Trunk 7106                               | X                                            |                                              |             |        |       |
| Subtransmission Breaker Short Circuit Violations                             |                                              |                                              |             | X      |       |
| Subtransmission Redesign & Rebuild: Slocum                                   |                                              |                                              |             |        | X     |
| Subtransmission Redesign & Rebuild: Small Projects & Reserve                 | X                                            |                                              |             |        |       |
| Subtransmission Redesign & Rebuild: Tie 1568                                 | X                                            |                                              |             |        |       |
| Subtransmission Redesign & Rebuild: Tie 4105                                 |                                              |                                              | X           |        |       |
| Subtransmission Redesign & Rebuild: Trunk 2237-ST                            | X                                            |                                              |             |        |       |
| Subtransmission Redesign & Rebuild: Trunk 2255                               | X                                            |                                              |             |        |       |
| Subtransmission Redesign & Rebuild: Trunk 3124                               |                                              |                                              | X           |        |       |
| Subtransmission Redesign & Rebuild: Trunk 4217                               | X                                            |                                              |             |        |       |
| Subtransmission Redesign & Rebuild: Trunk 7333                               | X                                            |                                              |             |        |       |
| Subtransmission Redesign & Rebuild: 40kV Capacitor Banks at Armada and Adair |                                              | X                                            |             |        |       |
| Subtransmission Redesign & Rebuild: Boyne                                    | X                                            |                                              |             |        |       |
| Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker         | X                                            |                                              |             |        |       |
| Subtransmission Redesign & Rebuild: Trunk 2308                               | X                                            |                                              |             |        |       |
| Subtransmission Redesign & Rebuild: Trunk 2419                               | X                                            |                                              |             |        |       |
| TCHPP Switchyard Upgrades                                                    |                                              |                                              |             |        | X     |
| Subtransmission Redesign & Rebuild: Cortland Station Expansion               |                                              |                                              | X           |        |       |
| Subtransmission Redesign & Rebuild: DUNN Station                             |                                              |                                              |             |        | X     |
| Subtransmission Redesign & Rebuild: Tie 810                                  |                                              | X                                            |             |        |       |
| Subtransmission Redesign & Rebuild: Trunk 3509                               | X                                            |                                              |             |        |       |
| Subtransmission Redesign & Rebuild: Badax Transformer 102 Addition           |                                              | X                                            |             |        |       |
| Subtransmission Redesign & Rebuild: Trunk 7105                               | X                                            |                                              |             |        |       |
| Subtransmission Redesign & Rebuild: Reverse Power Relay Scheme Program       |                                              |                                              |             |        | X     |

2

3 **Q86. How does the Company prioritize subtransmission projects within the**  
4 **Subtransmission Redesign & Rebuild Program?**

5 A86. As described above, the company's engineers identify eligible circuits and stations  
6 for the Subtransmission Redesign and Rebuild program by conducting a yearly  
7 loading analysis to identify circuits with planning criteria violations. In addition to  
8 the planning criteria violations, the Subtransmission Planning engineers monitor  
9 the reliability of the system and identify circuits with repeated reliability issues  
10 related to subtransmission failures. Once the list of eligible circuits is identified for  
11 the program, the violations are ranked based on severity. The Company considers  
12 six criteria when ranking the violations, described in Table 12. Individual projects  
13 are identified for the higher-ranking circuits and stations to alleviate the violations.

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**Table 12 Subtransmission Priority Criteria**

| Subtransmission<br>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 backup or the backup cannot support the load                                                                                                   |
| Load over Emergency Rating for Single Contingency | Total load when a subtransmission line exceeds the 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, total load served, and the ability to serve load from an alternate source |

Consistent with other strategic projects and programs, each individual Subtransmission Rebuild and Redesign project is prioritized using the GPM which is discussed in detail by Witness Kryscynski.

**Q87. How is the detailed scope for the Subtransmission Redesign & Rebuild Program projects defined?**

A87. After projects are identified and prioritized through the GPM model, Subtransmission Planning engineers develop detailed engineering scope for the selected projects. As the detailed scope is developed, engineers will identify the sections of the circuits that are creating the planning criteria violation and/or generating outage events, and those sections of circuits are addressed as part of the Subtransmission Redesign & Rebuild Program. Proposals are made to upgrade the



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1 limiting equipment or sections/areas of the subtransmission circuits. Therefore, the  
2 proposals will only upgrade what is necessary to solve the concern at hand and  
3 provide the necessary capacity needed for future load needs in the area. Engineers  
4 will validate the proposed projects through power flow studies, and they will  
5 conduct multiple technical reviews with subject matter experts (“SMEs”) in the  
6 Company to validate the solution/scope. As the technical reviews are conducted,  
7 alternatives to the defined scope are evaluated to find the most cost-effective  
8 solution.

9

10 As an example, the northeast area transformer project is driven by the need to  
11 prevent a low voltage condition (planning criteria violation) across the Thumb area  
12 under a single contingency (N-1) scenario, impacting power quality for  
13 approximately 37,000 customers. The loss of a northeast area transformer will  
14 result in low voltage on 40kV Tie lines in the northeast vicinity under a single  
15 contingency (N-1) scenario, impacting 29 distribution substations. In the event this  
16 contingency occurs, manual load shed would be enabled by SOC to prevent damage  
17 to customer and DTE Electric equipment due to this low voltage.

18

19 To resolve this severe low voltage condition, subtransmission engineering  
20 developed a project that will expand the existing station to install a second  
21 transformer in the northeast area that will serve as a backup in the event of the loss  
22 of the existing transformer. The northeast area transformer project will resolve the  
23 low voltage scenario, improve reliability for the area, and provide additional load  
24 capacity.

25 Alternatives were evaluated as part of this engineering analysis:

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- 1       • Alternative 1 – At least seven 40kV capacitors could be installed at the stations  
2       and substations in the Thumb area to resolve the low voltage conditions.  
3       Available space on the DTE Electric substation properties limits this option  
4       because additional property needs to be purchased adjacent to the Company's  
5       substations to allow the fence to be expanded to make room for new capacitors.  
6       The addition of this many capacitors could also lead to power quality issues for  
7       customers when capacitors are switching on, causing transient voltage spikes.  
8       In addition, this solution would not provide as much capacity benefit as the  
9       installation of a new northeast area transformer.
- 10      • Alternative 2 – Reconductor the tie lines out of the station with 636 AL  
11      conductor, which has a lower impedance (electrical resistance) than the existing  
12      3/0 ACSR (Aluminum Conductor Steel Reinforced) conductor. Lower  
13      impedance line or conductor effectively increases the ability of the line to carry  
14      load. The four tie lines in the area have a combined total 85 miles of overhead  
15      3/0 ACSR conductor. While it would technically solve the problem, this  
16      solution is higher cost and would take longer to implement.
- 17      • Alternative 3 – If the Company does not implement a project to resolve the  
18      voltage violations for this N-1 contingency situation, the Company would  
19      continue to operate with the risk that customers in the Thumb will have severe  
20      low voltage due to a fault on the northeast area transformer or its associated  
21      equipment. If this fault were to occur, DTE Electric may shed load until  
22      equipment can be restored or until portable generation is installed to support the  
23      load. Shutdowns of the northeast area transformer and its associated equipment  
24      for maintenance will also be restricted to periods of lower system load levels.

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1 Load growth in the area may have to be denied to avoid additional risk to the  
2 system and existing customers.

3  
4 After performing multiple technical reviews and evaluating alternatives,  
5 installing a second northeast area transformer proved to be the most timely and  
6 cost-effective solution.

7

8 **Q88. Does the Subtransmission Redesign & Rebuild program include reliability-**  
9 **driven projects?**

10 A88. Yes. In addition to thermal overloads and voltage planning criteria violations that  
11 can indirectly impact reliability, the Subtransmission Redesign & Rebuild Program  
12 also identifies and prioritizes projects to directly address poor circuit reliability; as  
13 shown in Table 11 above, there are four reliability-driven projects in the instant  
14 case. For example, Tie 4105 is a 62-mile circuit serving 7 substations  
15 (approximately 3,500 customers) in the rural northern part of the Company's  
16 service territory.

17

18 As shown in Table 13 below, Tie 4105 reliability performance began to degrade in  
19 2019. The substations served from Tie 4105 experienced frequent outages. These  
20 outages resulted in increased complaints to the Company and the Commission by  
21 the affected customers and communities. To mitigate the degrading reliability on  
22 Tie 4105, the Company performed maintenance work, such as pole top maintenance  
23 and line clearance, in the most problematic sections of the circuit over multiple  
24 years (2017-2020). These actions did not provide a permanent solution to improve  
25 the overall performance of the circuit, proving the need for a larger subtransmission

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1 hardening project with more robust construction including, among other things, re-  
2 conducting.

3

4

**Table 13 Tie 4105 Initiative Reliability Performance**

| Year | Total Momentary<br>Outages on Tie 4105 | Total Sustained<br>Outages on Tie 4105 | Total Customer<br>Minutes |
|------|----------------------------------------|----------------------------------------|---------------------------|
| 2015 | 3                                      | 3                                      | 4,530,656                 |
| 2016 | 10                                     | 3                                      | 3,060,346                 |
| 2017 | 9                                      | 4                                      | 4,671,876                 |
| 2018 | 10                                     | 3                                      | 1,804,047                 |
| 2019 | 9                                      | 7                                      | 9,990,554                 |
| 2020 | 1                                      | 7                                      | 3,798,693                 |
| 2021 | 4                                      | 6                                      | 7,641,562                 |
| 2022 | 5                                      | 7                                      | 1,155,311                 |

5

6

7

8

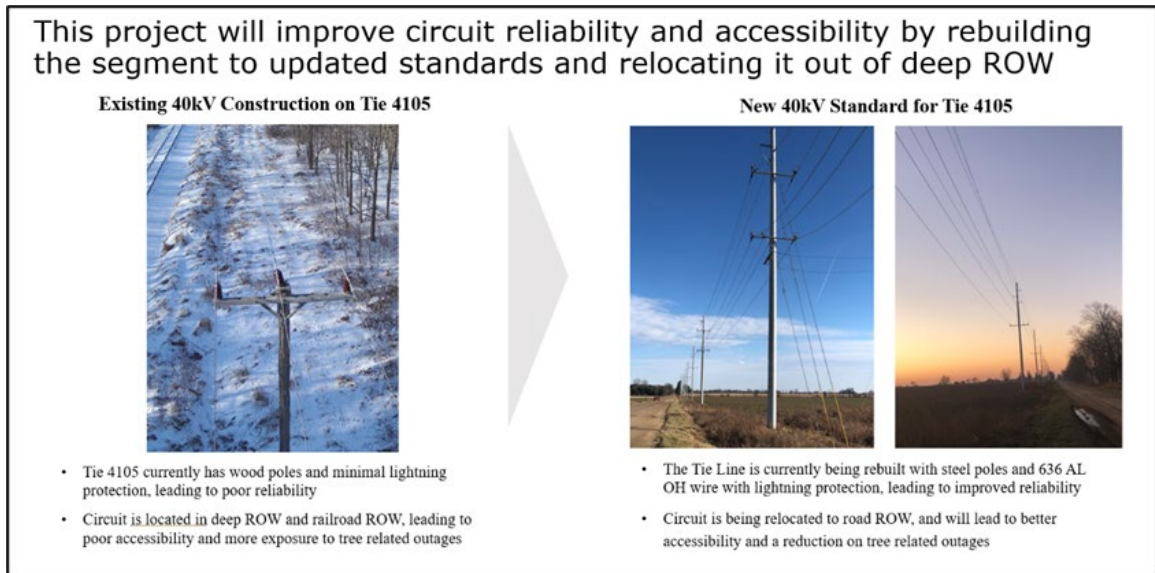
9

10

11

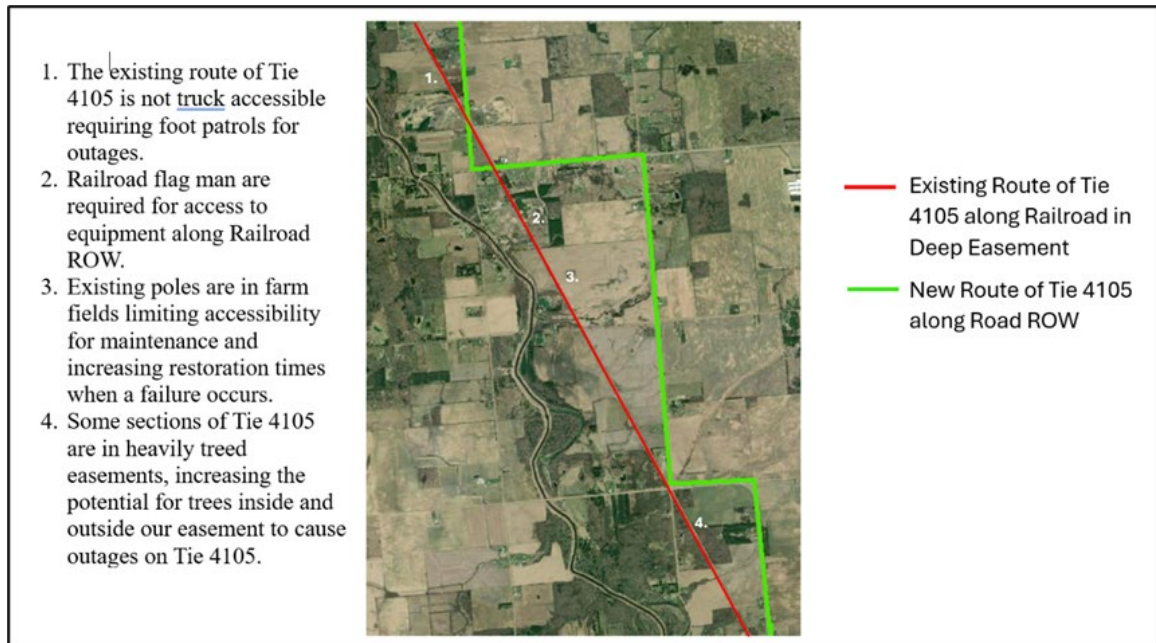
Therefore, a project was developed to rebuild and relocate approximately 35 miles (or 50%) of this circuit. This project was designed using the latest, resilience focused construction standards to address the seventy percent (70%) of the poles on Tie 4105 that are beyond their life expectancy, and involved relocation from deep, heavily-treed right-of-way to more truck accessible road right-of-way , as shown in Figures 26 and 27 below.

**Figure 26 Tie 4105 Existing Wood Poles vs. New Steel Poles**



2

**Figure 27 Tie 4105 Existing Route vs. New Route Along Road ROW**



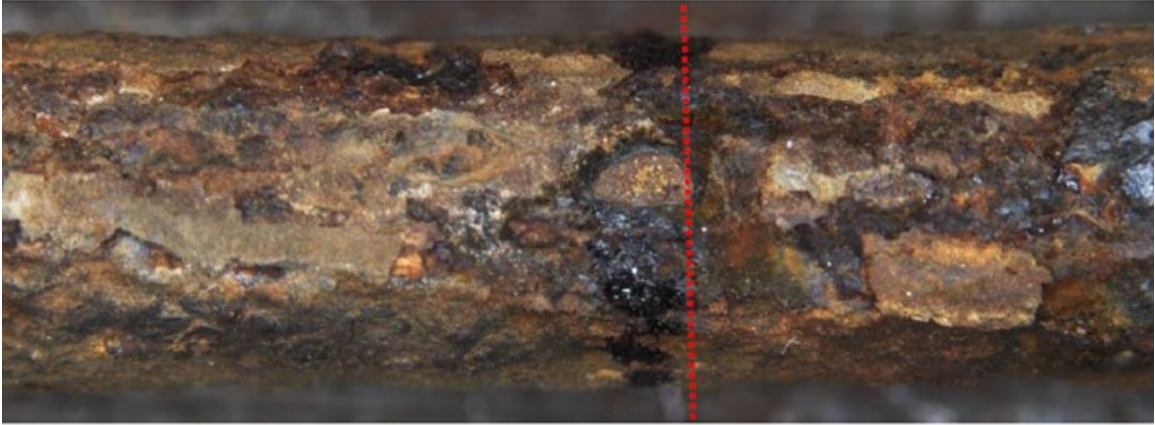
3

4 This project will rebuild the subtransmission circuit using 636 AL conductor to  
5 address the known issues with the current conductor in the field. Testing of the  
6 conductor samples from Tie 4105 demonstrated reduced tensile strength and the

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1 steel core zinc layer was no longer present to prevent further oxidation & corrosion,  
2 as shown in Figures 28 and 29. If not addressed, this will lead to conductor failure  
3 and a reduced resiliency during storm events.

4  
5 **Figure 28 Existing Tie 4105 Steel Core of 3/0 ACSR conductor showing**  
6 **corrosion**



7 **Figure 29 Existing Tie 4105 3/0 ACSR reduced tensile strength**

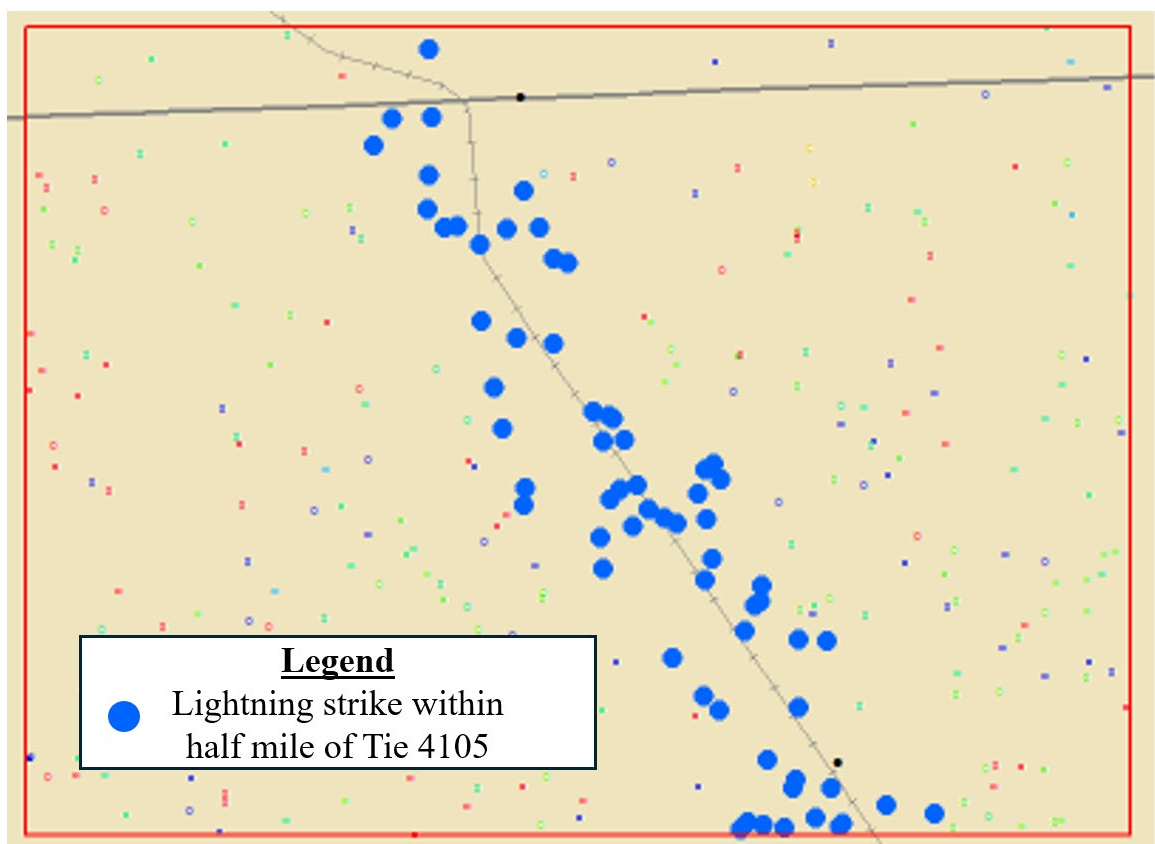


8  
9 Further, this Subtransmission Redesign & Rebuild project will address the lightning  
10 exposure of this circuit by adding in shield wire. Data from the FALLS® lightning  
11 database indicates that there were 65 lightning strikes located within a half mile of  
12 this 5-mile section of Tie 4105 between January 2016 and December 2018, shown

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as blue dots on the map in Figure 30 below. Lightning within a half mile can induce voltage surges on power lines causing equipment damage. Of these 65 lightning strikes, the data indicates there were 13 lightning strikes during this time interval that were direct strikes to the lines or immediately adjacent to them. See Figure 31 for the date, time, polarity, and intensity of the lightning events.

**Figure 30**      **Lightning strikes within a half mile of the 5-mile section of Tie 4105 between 2016 and 2018**



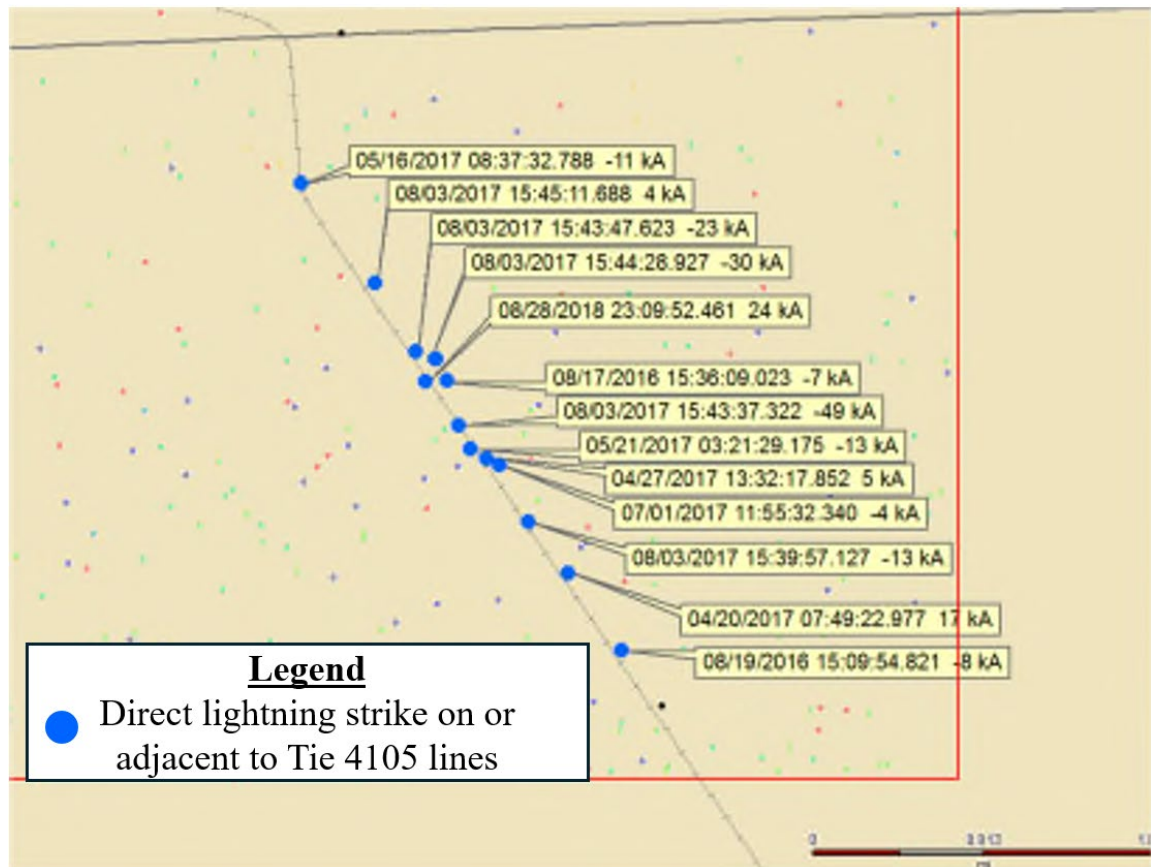


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1

2

**Figure 31 Lightning activity within a half mile of Tie 4105 between January 2016 and December 2018**



3

4

5

6

7

8

The Tie 4105 project began in 2020, and it is currently underway. This project is being implemented in 5 phases. Phase 1 was completed in 2023, phase 3 was completed in 2024, phase 4 is currently in construction targeted to complete in 2025, and phases 2 & 5 are expected to be complete by 2028. Table 14 below shows the improvement in Tie 4105 reliability after the completion of phases 1 and 3.



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**Table 14 Tie 4105 Reliability Improvement**

| Year                               | Total Momentary Outages on Tie 4105 | Total Sustained Outages on Tie 4105 | Total Customer Minutes from Tie 4105 Outages |
|------------------------------------|-------------------------------------|-------------------------------------|----------------------------------------------|
| 2015                               | 3                                   | 3                                   | 4,530,656                                    |
| 2016                               | 10                                  | 3                                   | 3,060,346                                    |
| 2017                               | 9                                   | 4                                   | 4,671,876                                    |
| 2018                               | 10                                  | 3                                   | 1,804,047                                    |
| 2019                               | 9                                   | 7                                   | 9,990,554                                    |
| 2020                               | 1                                   | 7                                   | 3,798,693                                    |
| 2021                               | 4                                   | 6                                   | 7,641,562                                    |
| 2022                               | 5                                   | 7                                   | 1,155,311                                    |
| Tie 4105 Phase 1 Completed in 2023 |                                     |                                     |                                              |
| 2023                               | 2                                   | 4                                   | 365,832                                      |
| Tie 4105 Phase 3 Complete in 2024  |                                     |                                     |                                              |
| 2024                               | 2                                   | 0                                   | -                                            |

2

3 **Q89. What are the benefits of the Subtransmission Redesign & Rebuild Program**  
4 **projects?**

5 A89. A rebuilt, hardened, resilient subtransmission system will improve safety,  
6 reliability, and operability, while also increasing capacity. As the Company  
7 implements these projects, it looks for opportunities to relocate subtransmission  
8 circuits from often inaccessible deep and railroad right-of-way locations to truck-  
9 accessible road right-of-way. In addition to significantly reducing the  
10 subtransmission circuit's exposure to tree damage, this greatly improves the line  
11 crew's access to the circuit from bucket trucks, leading to reduced cost and timing  
12 for tree trimming, maintenance and equipment replacement. When there is an  
13 outage event, it will reduce the patrol time allowing for quicker restoration.

14

15 In addition to improving accessibility, the Subtransmission Redesign & Rebuild  
16 Program rebuilds the identified segments to the Company's latest, more resilient  
17 construction standards by using steel poles, stronger conductor, stronger clamp top

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1 insulators, and shield wire for improved lightning protection. This allows the newly  
2 constructed subtransmission circuits to be more durable and resilient during severe  
3 weather events. The new stronger poles are able to withstand winds up to 90 mph  
4 resulting in a much more storm resilient subtransmission system. The larger wire  
5 standard conductor delivers multiple benefits such as providing significantly more  
6 capacity on each circuit, reducing the magnitude of voltage drop over long distances  
7 on the system, and additionally providing approximately twice the strength of  
8 existing conductors to withstand contact with a tree limb during storms or other tree  
9 related events.

10  
11 The underground subtransmission reliability will improve due to the removal of at-  
12 risk or overloaded cables. Additionally, rebuilding the subtransmission system will  
13 also remove aging equipment reducing the probability of equipment failures.  
14 Furthermore, the rebuilt subtransmission system will be designed to provide  
15 redundancy to reduce subtransmission level outages impacting customers.

16  
17 Additional capacity is achieved by upgrading to a larger conductor as the voltage  
18 drop is reduced over long distances. Therefore, this rebuilt and redesigned  
19 subtransmission system will support area load growth for existing and new  
20 customers, and with updated technology will provide the ability to support DER  
21 interconnections, including large-scale solar arrays. As the generation profile is  
22 expected to change with the integration of more DERs and the retirement of fossil  
23 generation plants, improvements to the subtransmission system will better support  
24 the changing power flows on the system.

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1   **Q90. Can you describe the Subtransmission Redesign & Rebuild Program projects**  
2       **included in this case?**

3   A90. Table 15 provides the high-level summary of the Subtransmission Redesign &  
4       Rebuild Program projects included in this case. Detailed information for each of  
5       these projects is provided in Exhibit A-23 Schedule M6.

**Table 15 Subtransmission Projects**

| Table 15 – Subtransmission Redesign & Rebuild Projects                       |                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                     |
|------------------------------------------------------------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Project Name                                                                 | Drivers                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                             |
| Ann Arbor System Improvements: State Substation                              | <p><u>Reliability</u>: 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.</p> <p><u>Capacity</u>: 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.</p> <p><u>Operability</u>: There is currently limited ability to jumper/transfer load to adjacent substations during emergency situations or for routine maintenance.</p> <p>This project, coupled with the other Ann Arbor System Improvements Projects Apex, Argo, and Buckler Circuit Conversions, will address these issues.</p>   |
| Ann Arbor System Improvements: Apex (Blue) Substation                        | <p><u>Reliability</u>: The existing distribution system in the Greater Ann Arbor area experience's frequent reliability and power quality issues. Voltage sags and outages are frequent in the area, negatively affecting customers.</p> <p><u>Capacity</u>: 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.</p> <p><u>Operability</u>: There is currently limited ability to jumper/transfer load to adjacent substations during emergency situations or for routine maintenance.</p> <p>This project, coupled with the other Ann Arbor System Improvements Projects State, Argo, and Buckler Circuit Conversions, will address these issues.</p> |
| Ann Arbor System Improvements: Argo 40kV Reconfiguration                     | <p><u>Capacity</u>: 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).</p> <p><u>Other Benefit</u>: This project avoids \$5M of work that would be required at the ARGO yard should the reconfiguration not take place.</p>                                                                                                                                                                                                                                                                                                                                                                                 |
| Subtransmission Redesign & Rebuild: Transformer High Side Protection Program | <p><u>Reliability</u>: 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.</p>                                                                                                                                                                                                                                                                                                                          |
| Subtransmission Redesign & Rebuild: Maxwell Amherst                          | <p><u>Operability</u>: Amherst industrial substation was partially relocated to Maxwell station during a trouble/emergent job. The driver for this project is to fully relocate Amherst industrial substation to Maxwell to meet the industrial customer service needs.</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                         |
| Subtransmission Redesign & Rebuild: Trunk 7106                               | <p>Trunk 7106 is in violation of the Subtransmission Planning Criteria and Distribution Design Order for thermal overloads. Trunk 7106 is loaded to 134% of the equipment's summer normal (N-0) rating with no capacity for new load. Trunk 7106 is loaded to 126% of the equipment's summer emergency (N-1) rating for the single contingency event of an outage on Trunk 2237 or Trunk 7151.</p> <p>Farmington (FRMTN) Substation automatic throwover has been placed on manual blocking to prevent equipment failure on Trunk 7106 due to overloads. 12.7 MVA of customer load at FRMTN substation will be dropped in the event of an outage of Trunk 7151. This is a violation of the Subtransmission Planning Criteria and Distribution Design Order.</p>                                      |
| Subtransmission Breaker Short Circuit Violations                             | <p><u>Safety/Reliability</u>: 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.</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                            |
| Subtransmission Redesign & Rebuild: Slocum                                   | <p>The Trenton Channel Power Plant, including all outlying structures and buildings are planned for retirement in 2022 with subsequent demolition. Trunk 1110, Trunk 1116, Trunk 1140 will be redesigned to remove all unused equipment that is currently being used to feed system service transformers at the power plant.</p>                                                                                                                                                                                                                                                                                                                                                                                                                                                                    |
| Subtransmission Redesign & Rebuild: Small Projects & Reserve                 | <p>This category includes small projects aimed at addressing thermal overloads and voltage violations on the subtransmission system.</p> <p>Trunk 2508:</p> <ul style="list-style-type: none"> <li><u>Capacity</u>: Trunk 2508 is loaded to 98% of its emergency rating, exceeding the Subtransmission planning criteria.</li> <li><u>Operability</u>: Load will automatically be shed at Centerline substation to prevent this equipment overload.</li> </ul> <p>Trunk 2506:</p> <ul style="list-style-type: none"> <li><u>Capacity</u>: Trunk 2506 section is loaded to 98% of its emergency rating, exceeding the Subtransmission planning criteria.</li> </ul>                                                                                                                                  |

| Table 15 – Subtransmission Redesign & Rebuild Projects                       |                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                  |
|------------------------------------------------------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Project Name                                                                 | Drivers                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                          |
|                                                                              | <ul style="list-style-type: none"> <li>• <u>Operability</u>: Load will automatically be shed at Centerline substation to prevent this equipment overload.</li> </ul> <p>Trunk 7114-7115:</p> <ul style="list-style-type: none"> <li>• <u>Capacity</u>: Trunk 7114-7115 is loaded to 120% of its emergency rating, exceeding the Subtransmission planning criteria.</li> <li>• <u>Operability</u>: Load will automatically be shed at Sargent and Gary substations to prevent this equipment overload.</li> </ul>                                                                                 |
| Subtransmission Redesign & Rebuild: Tie 1568                                 | <p><u>Capacity</u>: Tie 1568 is loaded to 99% of the equipment's summer emergency rating, exceeding the Subtransmission planning criteria.</p> <p><u>Operability</u>: There is an Emergency Load Control scheme at CROWN substation that will automatically shed load (10.1 MVA) to protect from overloading equipment and causing permanent damage</p>                                                                                                                                                                                                                                          |
| Subtransmission Redesign & Rebuild: Tie 4105                                 | <p><u>Reliability</u>: TIE 4105 has experienced frequent outages, escalated complaints, and is one of the worst performing Subtransmission lines.</p>                                                                                                                                                                                                                                                                                                                                                                                                                                            |
| Subtransmission Redesign & Rebuild: Trunk 2237-ST                            | <p><u>Capacity</u>: 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.</p> <p><u>Operability</u>: There is an Emergency Load Control scheme at Six Mile Substation that will automatically shed load to prevent from overloading equipment on Trunk 2237 and protect the equipment from any permanent damage</p>                                                                                                                                                         |
| Subtransmission Redesign & Rebuild: Trunk 2255                               | <p><u>Capacity</u>: Trunk 2255 is loaded to 110% of the Summer Emergency rating, exceeding the Subtransmission planning criteria.</p> <p><u>Operability</u>: Approximately 11 MVA of load will automatically be shed at Glendale and Villa substations to prevent this equipment overload.</p>                                                                                                                                                                                                                                                                                                   |
| Subtransmission Redesign & Rebuild: Trunk 3124                               | <p>Industrial Customer escalated a complaint indicating that TRK 3124 is in poor condition. Recently, the customer experienced outages due to broken equipment. A recent drone patrol indicated that TRK 3124 needs maintenance to improve reliability for multiple customers.</p>                                                                                                                                                                                                                                                                                                               |
| Subtransmission Redesign & Rebuild: Trunk 4217                               | <p><u>Capacity</u>: 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.</p> <p><u>Operability</u>: There is an Emergency Load Control scheme at Grosse Pointe and Vernier substations that will automatically shed load to protect from overloading equipment and causing damage for a single contingency event.</p>                                                                                                                                                      |
| Subtransmission Redesign & Rebuild: Trunk 7333                               | <p><u>Capacity</u>: Trunk 7333 is loaded to 129% of the summer normal rating and 126% of the summer emergency rating, exceeding the Subtransmission planning criteria.</p> <p><u>Operability</u>: Load will automatically be shed at Brazil &amp; Kenney substations to prevent this equipment overload.</p>                                                                                                                                                                                                                                                                                     |
| Subtransmission Redesign & Rebuild: 40kV Capacitor Banks at Armada and Adair | <p><u>Capacity</u>: 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. Voltage as low as 89% of nominal voltage are seen on Tie 810 for multiple single contingency scenarios, which violates the Subtransmission planning criteria. According to the criteria, during emergency conditions of a single contingency event (N-1), the voltage limits should be between 92% and 105% of nominal voltage.</p>                                    |
| Subtransmission Redesign & Rebuild: Boyne                                    | <p><u>Capacity</u>: Trunk 7909 is loaded to 120% of its summer emergency rating and Trunk 6759 is loaded to 107% of its summer emergency rating, violating the Subtransmission Planning Criteria. The criteria states emergency loading on the subtransmission system, resulting from the forced outage of any single element (N-1), shall not exceed 90% of the emergency rating of equipment. These two trunk lines have no remaining capacity for new load.</p> <p><u>Operability</u>: Load will be automatically shed at Omega and Beach Substations to prevent this equipment overload.</p> |
| Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker         | <p><u>Capacity</u>: Sandusky Transformer 101 is loaded to 126% of the equipment's summer normal rating, violating the Subtransmission Planning Criteria. The criteria states that the day-to-day loading (normal, N-0) on the subtransmission system shall not exceed 100% of the day-to-day rating of equipment. In the event an equipment failure occurs at Sandusky Transformer 101 due to overload, customers would experience low voltage and be at risk of load shed for an extended period until permanent repairs were made.</p>                                                         |
| Subtransmission Redesign & Rebuild: Trunk 2308                               | <p><u>Capacity</u>: Trunk 2308 is loaded to 99% of its summer emergency rating, exceeding the Subtransmission planning criteria.</p> <p><u>Operability</u>: There is an Emergency Load Control scheme at BENSU substation that will automatically shed load to protect from overloading equipment and causing permanent damage for a single contingency event.</p>                                                                                                                                                                                                                               |

| Table 15 – Subtransmission Redesign & Rebuild Projects                 |                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                        |
|------------------------------------------------------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Project Name                                                           | Drivers                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                |
| Subtransmission Redesign & Rebuild: Trunk 2419                         | <u>Capacity:</u> Trunk 2419 is loaded to 106% of its summer emergency rating, violating the Subtransmission planning criteria.<br><u>Operability:</u> The System Operations Center will manually shed load at Annchester Substation to prevent this equipment overload.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                |
| TCHPP Switchyard Upgrades                                              | Trenton Channel Power Plant (TCHPP) is being decommissioned and the existing Trenton switchyard will change operational authority from Energy Supply to Distribution Operations. In order for Transfer of Operational Authority to occur, the switchyard must be upgraded and brought up to current DO standards.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                      |
| Subtransmission Redesign & Rebuild: Cortland Station Expansion         | <u>Reliability:</u> Cortland Station was identified as a high-risk station in the Operational Risk Assessment.<br><u>Operability:</u> 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.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                    |
| Subtransmission Redesign & Rebuild: DUNN Station                       | Dunn substation has been disconnected from the customer and currently not serving any load. The equipment is ~70 years old and needs to be decommissioned. Due to operational concerns for Pinegrove Relocation Subtransmission project, cables to Dunn substation will need to be removed and Dunn substation will need to be decommissioned and removed. This will reduce safety issues by removing energized non-utilized equipment. Delays on Dunn decommissioning will likely delay the Pinegrove Relocation project.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                             |
| Subtransmission Redesign & Rebuild: Tie 810                            | <u>Capacity:</u> Tie 810 experiences low voltages in multiple single contingency scenarios, which violates the Subtransmission planning criteria. The criteria states that for emergency conditions of a single contingency event (N-1), the Subtransmission voltage limits are 92%-105% of the nominal voltage. There are 30 single contingency scenarios which result in voltage violations below the minimum voltage criteria (as low 87% of nominal voltage).<br>Tie 810 also experiences overloads in multiple single contingency scenarios. There are 21 unique thermal violations on Tie 810 for single contingency events. Six of these exceed 100% of the equipment's summer emergency rating.<br><u>Operability:</u> Load will automatically be shed at various substations to prevent this equipment overload.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                              |
| Subtransmission Redesign & Rebuild: Trunk 3509                         | <u>Capacity:</u> 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.<br><u>Operability:</u> There is an Emergency Load Control scheme at PATON substation that will automatically shed load to prevent from overloading equipment on Trunk 3509 and protect the equipment from any permanent damage.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                            |
| Subtransmission Redesign & Rebuild: Badax Transformer 102 Addition     | <u>Capacity:</u> The tielines out of Bad Axe station experience low voltage violations for the loss of Bad Axe Transformer 101, violating the Subtransmission Planning Criteria.<br><u>Operability:</u> 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 7105                         | <u>Capacity:</u> Trunk 7105 is loaded to 133% of the equipment's summer normal rating and 127% of the equipment's summer emergency rating, violating the Subtransmission Planning Criteria.<br><u>Operability:</u> An Emergency Load Control scheme is in place at Brooks Substation and Sargent Substation to prevent overloads on Trunk 7105.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                        |
| Subtransmission Redesign & Rebuild: Reverse Power Relay Scheme Program | <u>Operability:</u> Currently, to allow some of ITC shutdowns to be performed, DTE Operations has to pre-contingent set-up specific areas for load rejection due to the next contingency loss of another piece of equipment (N-1-1) resulting in power to flow from the 40kV (or 24kV) to the 120kV system through DTE Transformers (120/24kV or 120/40kV) to serve the distribution substation load or industrial load connected to the ITC system.<br><br>To pre-contingent set-up specific areas for load rejection, DTE must open breakers on the 40kV (or 24kV) system to prevent post-contingency back feeding. If this back-feed condition occurs then this would result in (1) severe overloads and/or low voltage conditions on the DTE system which could lead to cascading outages, damage DTE & customer equipment and (2) there would be lack of protection since there is no longer the ability to detect phase to ground faults on the 120kV system because it is a delta system and will operate like DTE 4.8kV system which is a major safety concern.<br><br>The DTE system must be setup for load rejections prior to starting ITC shutdown. These operating actions create 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. |

Line  
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1   **Q91.   What is the Subtransmission Small Projects and Reserve Program?**

2   A91.   There are times when the Company experiences emergent issues on the  
3           subtransmission system that are less complex, and that unlike the larger  
4           subtransmission projects can be executed without extensive engineering and  
5           planning. These projects are generally smaller in scope and level of investment,  
6           requiring \$500,000 or less in capital. The typical scope of work for these projects  
7           addresses thermal or voltage violations, under either normal or single contingency  
8           situations. Projects of this nature are identified during the yearly engineering  
9           analysis, which is the same methodology used to identify all the subtransmission  
10          projects under the Subtransmission Redesign & Rebuild Program. The Company  
11          has created a Small Projects and Reserve program that allows the Company to  
12          efficiently address these less complex issues on the subtransmission system in a  
13          short amount of time, without the more involved planning and engineering required  
14          for a larger, more extensive project. A high-level summary of these projects for  
15          2025 is provided in Table 15 above.

16

17   **Q92.   How do customers benefit from the Small Projects and Reserve program?**

18   A92.   Similar to other subtransmission projects, the Small Projects and Reserve program  
19           will provide multiple customer benefits including improved safety, improved  
20           reliability and operability, and increased capacity, but within a shorter period of  
21           time due to the much more limited scope and shorter schedule required to address  
22           identified system issues. The Small Projects and Reserve program has the ability  
23           to address the system conditions and provide more immediate benefits to customers  
24           with a relatively quick solution.

Line  
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1   **Q93. Are any Subtransmission investments included in the Infrastructure Recovery**  
2   **Mechanism (IRM)?**

3   A93. Yes. The Company's Subtransmission investments are partitioned between  
4   recovery through base rates and the Company's authorized IRM mechanism. For  
5   the historical, bridge and test periods in the instant case, Exhibit A-12 Schedule  
6   B.5.4.8 shows the partition between the base rates requested in Exhibit A-12  
7   Schedule B5.4 and authorized IRM amounts shown in Exhibit A-33 Schedule X1.  
8   Subtransmission investments beyond 2026, as described below, are proposed for  
9   inclusion in the IRM and shown in Exhibit A-33 Schedule X1. Company Witness  
10   Willis discusses the background of the IRM and supports the inclusion of  
11   investments in the IRM. Subtransmission prioritization in the IRM will follow the  
12   GPM prioritization as described by Company Witness Kryscynski, which includes  
13   using the EJ multiplier.

14

15   **Q94. What are the Company's expectations for investment in Subtransmission**  
16   **beyond the projected test year?**

17   A94. The Company will continue to need to invest in Subtransmission Redesign and  
18   Rebuild beyond the period covered in this case. The forecast of required investment  
19   beyond 2026 is:

- 20       • 2027:           \$105 million
- 21       • 2028:           \$115 million
- 22       • 2029:           \$120 million

23   This reflects the full expected investment for the Subtransmission program from  
24   2027 to 2029 and is included in this case as the basis for the Company's IRM  
25   request supported by Company Witness Willis.



Line  
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1 **VIII. SUG Program**

2 **Q95. What is the Company's strategy around strategic undergrounding pilot**  
3 **projects?**

4 A95. The combination of aged overhead infrastructure and increasingly frequent and  
5 severe storms has resulted in reliability impacts for many of our customers.  
6 Undergrounding protects the electrical infrastructure from increased storm  
7 frequency and severity, thus providing resiliency and improving reliability. An  
8 undergrounded circuit also has safety advantages since there are no downed wires  
9 during storm events. Furthermore, over the life cycle of the assets, undergrounding  
10 can provide the benefit of reduced maintenance and repair costs due to eliminating  
11 the need for tree trimming, pole top maintenance, and in most storm cases, trouble  
12 response.

13  
14 Through benchmarking, the Company has learned that many other utilities are also  
15 pursuing undergrounding of their existing overhead lines as a means to harden their  
16 systems for greater resiliency, increased reliability, and improved storm response.

17  
18 To take advantage of this unique opportunity to underground larger portions of the  
19 system while doing conversions, the Company plans to conduct pilot projects, and  
20 initially seek out areas where there are construction synergies, which could be  
21 achieved by jointly working with municipalities or other utilities.

22  
23 The main object of the pilot projects is to understand the challenges of  
24 undergrounding in a mature urban setting, define scenarios and situations when  
25 undergrounding can reap rewards in terms of safety, reliability, and resiliency

Line  
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1 benefits, and refine underground construction processes to gain cost efficiency on  
2 the installation. This approach will allow the Company to learn, develop best  
3 processes for undergrounding in mature urban, suburban, and rural areas while  
4 focusing on reducing implementation costs. An additional goal is to analyze the  
5 longer-term benefits of undergrounding to better support a refined benefit-to-cost  
6 analysis in the future.

7

8 These pilot projects will also allow the Company to further demonstrate the benefits  
9 of undergrounding and determine when/where this design choice can be applied  
10 effectively.

11

12 **Q96. Why did the Company initially choose to pilot undergrounding in a mature**  
13 **urban environment?**

14 A96. An urban environment was initially selected to address the various operational  
15 challenges I have explained with respect to 4.8kV ungrounded delta system rear-  
16 lot construction, and to improve storm response resiliency by reducing the number  
17 of customer services down.

18

19 To achieve these objectives, the construction method utilized is to bore conduit for  
20 primary and secondary connections instead of trenching which can be more  
21 disruptive. To improve storm response and resiliency for single customer outages,  
22 often of longer duration in a large storm, the Company is also undergrounding  
23 customer service drops.

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1 The factors of the mature urban neighborhood environment and undergrounding  
2 customer services has resulted in the Company's undergrounding costs being  
3 higher when compared with other utilities' scope of implementing undergrounding  
4 in a less challenging rural environment with a reduced scope that does not include  
5 service drop replacement.

6

7 **Q97. Has the Company completed any SUG pilot projects?**

8 A97. Yes. In Case No. U-20169, the Company was asked to explore alternative  
9 infrastructure designs to eliminate rear-lot overhead infrastructure and its  
10 associated challenges. To study an alternative design (rear lot undergrounding), the  
11 Company developed the Appoline pilot project that was completed in October  
12 2023.

13 To study the front lot undergrounding design alternative and determine the potential  
14 cost savings by working with other utilities, the Company developed the Buffalo-  
15 Charles pilot project, the majority of which was completed in 2024.

16

17 **Q98. What has the Commission said regarding the Company's SUG Program?**

18 A98. In Case No. U-21534, the Commission explained that it "continues to see value in  
19 undergrounding for targeted areas where undergrounding is shown to be the best  
20 option," though the Commission also noted that it has "significant and ongoing  
21 concerns over DTE Electric's support for its SUG pilots."<sup>26</sup>

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<sup>26</sup> Case No. U-21534 - Commission Order, January 23, 2025, p.139.

Line  
No.

1   **Q99. What specific concerns did the Commission raise with respect to the**  
2       **Company's support for the projects?**

3   A99. The Commission explained that it was concerned that the Company's BCA did not  
4       account for safety and resiliency. Considering the Commission's feedback, the  
5       Company delayed the two pilot projects originally planned to execute in 2025 to  
6       focus on improving the BCA model.

7

8   **Q100. What efforts has the Company undertaken to address the Commission's**  
9       **observations?**

10   A100. In Case No. U-21534, the Company stated that the BCA used could be improved  
11       by developing approaches to consider the benefits of safety and resiliency. The  
12       challenge for the Company is and has always been quantifying safety given the  
13       challenges in defining the value of a human life. As far as resiliency, the BCA in  
14       the instant case does consider the impacts of long-duration outages on the customer  
15       through the ICE calculator, including an enhancement that uses extrapolated  
16       Interruption Cost Estimate ("ICE") calculator values to estimate the impact.  
17       Additionally, the BCA approach in the instant case also includes enhancements to  
18       simulate the high-impact, low-probability events that result in multi-day restoration  
19       times but may only impact DTE Electric once in 20 or even 50 years. Currently,  
20       the industry has not yet developed a standard approach to calculate the additional  
21       benefits of resiliency. Despite these challenges, The Company retained a third-  
22       party independent consultant (1898 & Co.) to help develop approaches to better  
23       account for these two factors.

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1 **Q101. What did the Audit Report say about the Company’s SUG Program?**

2 A101. The Audit Report found that the Company was “correctly approaching  
3 consideration of a significantly scaled undergrounding program.”<sup>27</sup> Further, the  
4 Report noted that the Company “has been engaged in conducting one pilot and is  
5 appropriately planning a second, moderately scoped project.”<sup>28</sup>

6

7 **Q102. Is the Company developing additional undergrounding pilot projects?**

8 A102. Yes. The Company is currently developing two additional undergrounding pilot  
9 projects. One pilot project (Attica) is being developed in a rural area and the other  
10 (Spruce) in a suburban neighborhood. The investments for these projects are shown  
11 in Exhibit A-12, Schedule B5.4, page 12, line 68.

12

13 **Q103. Did the Company conduct BCAs for the two pilot programs?**

14 A103. Yes. The Company worked with a third party (1898 & Co.) to conduct a BCA for  
15 the Attica and Spruce undergrounding projects. The BCA ratio for Attica was 1.51,  
16 while the BCA for Spruce was 0.69. This analysis was performed by Witness De  
17 Stigter.

18

19 **Q104. Has the Company engaged with local communities / customers on the two pilot**  
20 **program projects in the instant case?**

21 A104. Yes. Related to the Spruce project, while participating in a community meeting in  
22 September 2023, the Company learned of City of Ann Arbor community plans to  
23 replace the roads within the impacted subdivision. This presented a unique synergy  
24 opportunity to install electrical conduit for road crossings during spring and

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<sup>27</sup> Audit Report, Part 2, at 85-86.

<sup>28</sup> Audit Report, Part 2, at 85-86.

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1 summer 2024 while the roads were being reconstructed. This allowed the Company  
2 to avoid the cost impact of breaking down and restoring the roadway as those costs  
3 would be borne by the community. Additionally, the Company has had multiple  
4 discussions with the home owner's association ("HOA") for the impacted  
5 subdivision to explain the impacts of the project. Since Attica has a smaller number  
6 of customers impacted, the Company directly communicated with each of the  
7 customers involved.

8

9 **Q105. Why was Attica selected as a pilot project?**

10 A105. Attica was selected as a pilot project to expand and enhance the Company's  
11 understanding of strategic undergrounding for rural circuit topologies. While some  
12 planning and constructing aspects of undergrounding in rural environments are less  
13 complex than a dense urban setting, rural circuits also can present distinct  
14 challenges, including significant elevation changes, dense vegetation, wetlands,  
15 and wildlife impacts. Additionally, lower customer density in rural areas influences  
16 both the type and quantity of equipment required for reliable service.

17 The Attica circuit features a straight-line lateral section, which provides an  
18 opportunity to optimize undergrounding cost efficiency in a rural environment.  
19 Rural environments present fewer obstacles in construction, such as buildings,  
20 sidewalks, and dense utilities compared to an urban environment. Open fields  
21 provide an easier path of installation compared to rocky or paved urban landscapes,  
22 and fewer traffic control measures are required.

23

24 This approach is expected to be applicable to many rural laterals across the  
25 Company's service territory where overhead lines pass through more heavily treed

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1 areas. By strategically undergrounding select sections, the Company can minimize  
2 overhead infrastructure costs, reduce maintenance needs, and decrease outage risks  
3 caused by falling trees. The Attica circuit's poor SAIDI performance places it in  
4 the fourth quartile, making it a suitable pilot project to gain additional  
5 understanding of undergrounding in a rural environment.

6

7 **Q106. What is the scope of the Attica pilot project?**

8 A106. The Attica pilot project involves converting a distribution circuit lateral serving 37  
9 customers from overhead to underground in Attica Township. The existing  
10 overhead primary, located in a deep right-of-way and surrounded by dense trees,  
11 poses significant challenges for crew accessibility. This project will relocate  
12 underground all primary overhead while keeping the customer services overhead.  
13 Given the low customer density in the area, the design helps the Company optimize  
14 costs for undergrounding in a rural environment. This scope is different than the  
15 two urban pilots that the Company has already completed.

16

17 **Q107. What is the timing of the Attica pilot project?**

18 A107. Attica pilot project engineering was completed in October 2024. Detailed design  
19 was completed in January 2025. Project construction is expected to start in 2026.

20

21 **Q108. Why was Spruce selected as a pilot project?**

22 A108. The rebuild on a portion of the Ann Arbor circuit DC9836 Spruce was originally  
23 proposed as an overhead rebuild as part of the ISO Conversion Program. While  
24 participating in a community meeting in September 2023, the Company learned of  
25 City of Ann Arbor community plans to replace the roads within the impacted

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1 subdivision. This presented a unique synergy opportunity to install electrical  
2 conduit without the cost impact of breaking down and restoring the roadway as  
3 those costs would be borne by the community.

4

5 **Q109. What is the scope of the Spruce pilot project?**

6 A109. The Spruce pilot project will convert an area of 228 customers from overhead to  
7 underground to improve reliability by reducing overhead exposure to trees.  
8 Installation of approximately 2.5 miles of front-lot, single phase underground  
9 residential distribution cables will facilitate the removal of approximately 1.6 miles  
10 of overhead primary lines. All new infrastructure will be built to 13.2kV standards,  
11 with 4.8kV overhead equipment being removed upon project completion.

12

13 **Q110. What is the timing of the Spruce pilot project?**

14 A110. Spruce pilot project engineering and detailed design will be completed in 2025.  
15 Project construction is expected to start in 2026.

16

17 **Q111. Why does the Company believe it is important to continue to implement**  
18 **undergrounding pilot projects?**

19 A111. The Company believes that undergrounding brings a set of unique benefits and is  
20 of high interest to our customers and other stakeholders. Undergrounding is the  
21 only investment option that fully eliminates the safety risk associated with downed  
22 wires and structures. Undergrounding provides the highest overall benefit in  
23 reducing emergent reactive costs and customer outages. Undergrounding is the  
24 most resilient option for severe weather-related events. Due to these advantages of  
25 undergrounding, the Company believes that it needs to conduct additional pilots to



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1 continue to learn and focus on reducing implementation costs to increase the overall  
2 benefit to cost ratio.

3

4 Learnings from these projects will be used to refine the current benefit cost models  
5 to help identify segments of overhead infrastructure that are good candidates for  
6 undergrounding. Furthermore, this approach will allow the Company to develop a  
7 more cost competitive undergrounding program.

8

9 **Q112. Are there additional topics that you would like to discuss?**

10 A112. Yes. In the January 23, 2025 Order in Case No. U-21534, the Commission directed  
11 the Company to “propose, in consultation with the Commission Staff and other  
12 interested parties, tariff language to modify its current Tariff C-27.00 to include a  
13 limited contribution-in-aid-of-construction waiver related to the difference in costs  
14 associated with customers connected to 4.8 kilovolts and those connected at 13.2  
15 kilovolts.”<sup>29</sup>

16

17 **Q113. Is the cost associated with connecting new customer load driven by 4.8kV or**  
18 **13.2kV availability?**

19 A113. No. The cost to connect a new customer is a direct function of each individual  
20 request and is a result of a variety of variables that are not solely a function of 4.8kV  
21 or 13.2kV circuit voltage. These variables can include, but are not limited to,  
22 magnitude of load request, site plan details, relocation requests, and existing utility  
23 system characteristics (substation / circuit load, equipment ratings, etc.). While  
24 13.2kV circuits do have a higher load-carrying capability than lower voltages, they

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<sup>29</sup> Case. No. U-21534 - Commission Order, January 23, 2025, pp. 466-67.

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1 typically carry more load, so connecting new customer loads may still require  
2 additional system upgrades. Conversely, there are instances in which sufficient  
3 capacity exists on a 4.8kV system, allowing the Company to connect new  
4 customers without the need for system upgrades, which demonstrated the fact that  
5 the cost to connect customers is largely independent of the voltage of the  
6 distribution system to which they're attached. Further, I will note that Company  
7 Witness Willis proposes a change to the Company's tariff in compliance with the  
8 Commission's directive regarding a partial waiver for the contribution in aid of  
9 construction should there be a difference in cost to connect new load to the  
10 distribution system.

11

12 **Q114. Can you summarize the key themes of your testimony?**

13 A114. Yes. Projects in the Infrastructure Redesign and Modernization pillar are  
14 reasonable, prudent, and a key part of the Company's plan for the grid of the future  
15 and fundamentally change the way the grid operates. These projects add capacity  
16 by converting the distribution system to a higher voltage for growing customer load,  
17 reduce outages and shorten outage restoration time by incorporating modern  
18 technology and equipment, harden the grid, improve redundancy and resiliency of  
19 the system, and increase safety. IRM treatment of these types of investments can  
20 benefit customers by ensuring that projects are consistently deployed where they  
21 are needed most.

22

23 The projects in this pillar are vital to support the continued resurgence of the city  
24 of Detroit and to provide the energy needed to ensure a bright future for Michigan.

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- 1    **Q115. Does this conclude your direct testimony?**
- 2    A115. Yes, it does.

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. )

## QUALIFICATIONS

## DIRECT TESTIMONY

STEPHEN P. RADEMACHER

**DTE ELECTRIC COMPANY**  
**QUALIFICATIONS AND DIRECT TESTIMONY OF STEPHEN P. RADEMACHER**

Line  
No.

1     **I.   Background & Qualifications**

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

3     A1.   My name is Stephen P. Rademacher, and my business address is One Energy Plaza,  
4           Detroit, Michigan, 48226. I am employed by DTE Electric Company (DTE Electric  
5           or Company).

6  
7     **Q2.   On whose behalf are you testifying?**

8     A2.   I am testifying on behalf of DTE Electric.

9  
10    **Q3.   What is your educational background?**

11    A3.   I earned a Bachelor of Science degree in Electrical Engineering in 2008 and a  
12          Master's degree in Business Administration in 2014, both from the University of  
13          Michigan, Dearborn.

14  
15    **Q4.   Please summarize your professional experience.**

16    A4.   I began my career with DTE Electric in 2008 as a Planning and Reliability Engineer  
17          in Distribution Operations. My responsibilities included performing planning  
18          studies to address capacity and voltage issues driven by new customers and general  
19          load growth. I was also responsible for system changes and upgrades to improve  
20          reliability and power quality for distribution customers, for which I conducted  
21          evaluations for power quality issues. In 2014, I became a Supervisor over Power  
22          Equipment and Relay Test Technicians, who were responsible for the testing of the  
23          Company's major substation equipment (transformers, breakers, switches, relays,  
24          and DC systems). This included both testing new installations and troubleshooting

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1 issues or failed equipment. In 2017, I became a Senior Strategist within Distribution  
2 Operations, and was responsible for developing long-term project/program  
3 implementation plans and priorities. In 2018, I became the Engineering Manager  
4 of the Engineering Support and Planning Center of Excellence team that was  
5 responsible for the processes, training and adherence tracking for the service and  
6 project Planners that provided detailed design to overhead and underground crews  
7 for construction. In 2019, I became the Engineering Manager of the Power Delivery  
8 Planning Group that is responsible for the planning and reliability of the DTE  
9 Electric high voltage distribution system that includes voltage levels of 24 kV, 41.6  
10 kV and 120 kV. This group completed engineering design of all facilities and  
11 systems that serve new and existing large industrial substations and general-  
12 purpose substations, provided necessary capacity and maintained adequate voltage  
13 to accommodate any regular system load growth, reviewed any changing or new  
14 generation interconnections to the system, and provided a connection between the  
15 International Transmission Company, dba ITC Transmission (ITCT) planning team  
16 and DTE Electric. In 2023, I worked on a special assignment to lead the technical  
17 Engineering responses to the Michigan Public Service Commission (MPSC or  
18 Commission)-directed third-party audit of DTE Electric's distribution system,  
19 which produced the Audit Report filed in Case No. U-21305 (Audit). In 2024, as  
20 the Audit neared completion, I started my current role as the Engineering Manager  
21 over Standards, New Technology, Interconnections and Distribution Operations  
22 NERC Compliance.

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1 **Q5. What are your current duties and responsibilities?**

2 A5. In my current position as the Engineering Manager of the Standards, New  
3 Technology, Interconnections and Distribution Operations NERC Compliance  
4 Group, my responsibilities include:

- 5 1. Developing, maintaining, and advocating compliance to the engineering  
6 standards that are used to create detailed design packages and executed by  
7 construction crews in the field;
- 8 2. Evaluating and developing implementation plans for new technologies that  
9 include equipment and some software applications;
- 10 3. Reviewing and approving applications for interconnections of new  
11 generation sources on the distribution system with a focus on maintaining  
12 safe and reliable policies/practices;
- 13 4. Reviewing, tracking/reporting, and maintaining compliance with North  
14 American Electric Reliability Corporation (NERC) compliance activities  
15 and standards that are handled by and affect the various Distribution  
16 Operations Engineering teams.

17

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

20 A6. Yes. I sponsored testimony in Case No. U-21089.<sup>1</sup>

21

22 **Q7. How is your testimony organized?**

23 A7. My testimony is organized as follows:

---

<sup>1</sup> Case No. U-21809 was captioned "In the matter of the Application of DTE Electric Company for an administrative determination regarding the proper classification of certain facilities and to submit findings to the Federal Energy Regulatory Commission."

Line  
No.

- 1 Section I: Background & Qualifications
- 2 Section II: Overview
- 3 Section III: Executive Summary
- 4 Section IV: Technology & Automation Investment Details



Line  
No.

1     **II.   Overview**

2     **Q8.   What is the purpose of your testimony?**

3     A8.   The purpose of my testimony is to:

4           1. Introduce the Technology & Automation Pillar of DTE Electric's  
5           investments in Distribution Operations and describe the categories of  
6           investments within this pillar and the Company's drivers for these  
7           investments; and

8           2. Support, as reasonable and prudent, the historical capital expenditures for  
9           2023 and the projected capital expenditures for the 24-month bridge period  
10          between January 1, 2024, through December 31, 2025, and the projected  
11          test year of the twelve months ending December 31, 2026, in the  
12          Technology & Automation Pillar of DTE Electric's Distribution Operations  
13          (DO) strategic investment portfolio.

14

15    **Q9.   Can you summarize your testimony?**

16    A9.   The Technology & Automation Pillar is one of four pillars of DTE Electric's  
17          Distribution Operations (DO) investments, as introduced by Company Witness  
18          Chiu, and reflected in the Company's most recent Distribution Grid Plan filed in  
19          Case No. U-20147. DTE Electric continues to make significant distribution and  
20          subtransmission system investments in the Technology & Automation Pillar as part  
21          of its multi-year strategy to rebuild, modernize, and automate its approximately  
22          46,000 miles of circuits. The investments supported by my testimony will enable  
23          the Company to reasonably, prudently, and effectively utilize the most current  
24          technologies to modernize its grid and achieve greater safety, reliability, and  
25          efficiency to the benefit of the Company's customers. The majority of the

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investments presented in my testimony were approved for recovery in the Company's 2024 Electric Rate Case, Case No. U-21534, and many of those projects and programs are already providing benefits to customers. My testimony also describes the scope and justification for new Technology & Automation Pillar projects that DTE Electric has identified as needed to further the Company's distribution grid modernization investments, the expenditures for which should also be approved. Taken together, these investments will position DTE Electric to fully utilize modern distribution system technology to provide more reliable service to customers.

**Q10. Are you sponsoring any exhibits in this proceeding?**

A10. 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:

| <u>Exhibit</u> | <u>Schedule</u> | <u>Description</u>                                                                           |
|----------------|-----------------|----------------------------------------------------------------------------------------------|
| A-12           | B5.4            | Projected Capital Expenditures, Distribution Plant – Technology & Automation (pg. 1-2,14-23) |
| A-23           | M7              | Distribution Plant Capital Project Detail – Technology & 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                                                                        |

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|   |      |        |                                             |
|---|------|--------|---------------------------------------------|
| 1 | A-12 | B5.4.7 | Pilots: NWA: EV Charging Demonstrations     |
| 2 | A-12 | B5.4.8 | Electric Rate Case (ERC) and Infrastructure |
| 3 |      |        | Recovery Mechanism (IRM) Revenue Recovery   |
| 4 |      |        | Partition                                   |
| 5 | A-19 | I1.1   | Telecom Reliability                         |
| 6 | A-19 | I1.2   | Telecom Cost                                |

7

8 **Q11. Were these exhibits prepared by you or under your direction?**

9 A11. Yes, they were.

10

11 **III. Executive Summary**

12 **Q12. How does the Technology & Automation Pillar of DTE Electric's distribution**  
 13 **investment strategy fit into the Company's overall Distribution Operations**  
 14 **investment strategy?**

15 A12. The Technology & Automation Pillar of DTE Electric's distribution investment  
 16 strategy fits within the Company's Strategic Capital category of capital investment,  
 17 as described in the direct testimony of Company Witness Chiu. Strategic Capital  
 18 projects and programs fall into three pillars, including Technology & Automation,  
 19 Infrastructure Resilience and Hardening, and Infrastructure Redesign and  
 20 Modernization. These projects and programs represent investments made to  
 21 improve safety, reliability and operability, and grid automation and modernization.

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1   **Q13. What is included in the Technology & Automation Pillar of DTE Electric's**  
2       **distribution strategy investment?**

3   A13. When many people think of the distribution grid, they think of the more visible  
4       components, such as poles, overhead lines and transformers, and large equipment  
5       in substations. However, inherent to grid modernization, new technologies that are  
6       less visible to the public are becoming an increasingly fundamental and essential  
7       part of the grid, improving the way modern electric grids operate and resulting in  
8       improved safety, reliability, and operability. These technologies include the  
9       integrated software system that models and allows control of grid devices and the  
10      communication system that allows for two-way flow of data between system  
11      operations personnel and field devices to create a smart grid. Investment in these  
12      technologies enables the more visible equipment and provides new opportunities to  
13      improve operations in ways that benefit customers by reducing the number of  
14      outages they experience and the duration of outages that do occur.

15

16      These improvements include for example the ability to mitigate the safety hazard  
17      of potentially energized downed wires on the 4.8 kV Delta system. Reliability  
18      improvements result from automatically detecting and isolating outages to limit the  
19      number of impacted customers after a system event. Real-time visibility for system  
20      operators and engineers into circuit and substation loading data improves the  
21      operability of the system. This visibility is critical to efficiently manage circuits to  
22      accommodate electric vehicles (EV) and an increasing number of Distributed  
23      Energy Resources (DER) such as solar and energy storage. Enabling all these new  
24      improvements requires a robust telecommunication system at the core. The

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1 Technology & Automation Pillar encompasses investments that will modernize  
2 DTE Electric's grid to benefit customers for decades to come.

3

4 **Q14. What are the primary drivers of DTE Electric's investments in the Technology**  
5 **& Automation Pillar?**

6 A14. The Company's Technology & Automation investments are driven by the  
7 following key drivers:

8 1. Effectively utilize modern distribution system technology to provide safer,  
9 more reliable service to customers;

10 2. Expand distribution automation to increase the Company's ability to  
11 remotely monitor and control the distribution system;

12 3. Balance continuous optimization with prudent investment planning by  
13 replacing outdated or damaged systems and technology and applying  
14 updates to keep pace with a continuously evolving technology landscape;

15 4. Modernize grid communications to enhance efficient and safe storm  
16 restoration capability and support daily operation of the grid;

17 5. Mitigate cybersecurity risk; and

18 6. Comply with evolving regulatory requirements.

19

20 **Q15. What categories of investments constitute the Technology & Automation**  
21 **Pillar?**

22 A15. The Technology & Automation Pillar investments can be grouped broadly into the  
23 categories of Grid Automation and Operational Technology. The Grid Automation  
24 and Operational Technology (OT) categories include the following key sub-

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1 categories of investment shown below in Table 1, as discussed in more detail later  
2 in my testimony:

3 **Table 1 Technology & Automation Key Investment Categories**

| Grid Automation        |                                                    |
|------------------------|----------------------------------------------------|
|                        | Distribution Automation                            |
|                        | Grid Automation Telecommunications                 |
|                        | Conservation Voltage Reduction (CRV/VVO)           |
|                        | Non-Wire Alternatives (NWA) Pilots                 |
|                        | Grid Edge Insights and New Technology              |
|                        | Distribution Sensing and Monitoring (Line Sensors) |
| Operational Technology |                                                    |
|                        | Grid Management                                    |
|                        | Distribution Planning                              |
|                        | Work Management and Scheduling                     |
|                        | Asset Management                                   |
|                        | Mobile Technology                                  |

4

5 **Q16. What type of investments are included in the Grid Automation category of**  
6 **Technology & Automation?**

7 A16. Grid Automation is focused on the physical technology infrastructure needed to  
8 support the efficient control and operation of a modern distribution grid. The  
9 Company's investments in this category focus on grid control and operation  
10 projects that will directly impact the improved safety and reliability of service  
11 provided to customers. These investments include reclosers, grid  
12 telecommunications supporting infrastructure, Conservation Voltage Reduction

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1 (CVR) and Volt Var Optimization (VVO), and infrastructure to support Non-Wires  
2 Alternatives (NWA), DER, and EV.

3 **Q17. What type of investments are included in the Operational Technology category**  
4 **of Technology & Automation?**

5 A17. Operational Technology investments represent a set of enabling technologies that  
6 interact closely with, and are tailored to support the objectives of, Grid Automation.  
7 These investments provide the essential tools to support and implement the  
8 Company's Grid Automation investments. Examples include the Advanced  
9 Distribution Management System (ADMS) applications and Every Day Daily Plan  
10 (EDDP).

11

12 **Q18. What level of investments in the Technology & Automation Pillar does your**  
13 **testimony support?**

14 A18. My testimony supports \$160.4 million of Technology & Automation Pillar  
15 investments in the 2023 historical test year (Exhibit A-12, Schedule B5.4, page 1,  
16 line 21, column (b)), \$337.5 million in the 24-month bridge period between  
17 January 1, 2024, through December 31, 2025 (Exhibit A-12, Schedule B5.4, page  
18 1, line 21, column (e)), and \$229.1 million in the projected test year spanning from  
19 January 1, 2026, to December 31, 2026 (Exhibit A-12, Schedule B5.4, page 1, line  
20 21, column (f)). Any variances associated with these investments are addressed by  
21 Witness Chiu.

22

23 **Q19. Where are the details of the Company's Technology & Automation capital**  
24 **investment provided?**

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1 A19. The details of the Technology & Automation capital investment are provided in the  
2 following exhibits and schedules:

- 3 • Exhibit A-12, Schedule B5.4, page 14-15 – Capital Investment
- 4 • Exhibit A-12, Schedule B5.4.1- B5.4.7 – NWA Pilot Informational
- 5 Documents; and
- 6 • Exhibit A-23, Schedule M7 – Capital Summary.

7

8 **Q20. Are any of the investments presented in your testimony further supported by**  
9 **another DTE Electric witness?**

10 A20. Yes. As I discuss further below in Section IV, the Company retained 1898 & Co.,  
11 a consulting arm of Burns and McDonnell, to conduct benefit-cost analyses (BCA)  
12 for projects in the Distribution Automation and Grid Automation  
13 Telecommunications categories of Grid Automation investments. Witness De  
14 Stigter of 1898 & Co. supports the structure and results of the BCAs. My testimony,  
15 in Sections IV.a.i and IV.a.ii, provides the descriptions and costs of these projects  
16 and discusses the benefits they will bring to customers consistent with Witness De  
17 Stigter's testimony and exhibits which evaluate the relationship between the costs  
18 and benefits.

19

20 **Q21. What was the overall outcome of the Audit with respect to DTE Electric's**  
21 **Technology & Automation investments?**

22 A21. First, as discussed further in Section IV.a.i of my testimony, the Audit  
23 recommended that the Company condition its future expansion of recloser  
24 installations on the development of additional information regarding additional



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1 reclosers' likely contribution to reliability.<sup>2</sup> Second, the Audit's conclusions  
2 support the Company's planned investments in all categories of Operational  
3 Technology.<sup>3</sup> Overall, the Audit was supportive of the Company's Technology &  
4 Automation investments.

5

6 **Q22. How does your testimony address the Audit's conclusions and**  
7 **recommendations as they relate to Technology & Automation investments?**

8 A22. My testimony addresses the Audit's conclusions and recommendations as they  
9 relate to DTE Electric's Technology & Automation investments, and the  
10 Company's current plans for those projects, in the individual subsections discussing  
11 those investments below. Specifically, I discuss the Audit's conclusion and  
12 recommendation and the Company's implementation plan for recloser installation  
13 in Section IV.a.i (Distribution Automation) and I discuss the Audit's conclusions  
14 regarding the Company's investments in the OT project categories in Sections  
15 IV.b.i through IV.b.v.

16

17 **IV. Technology & Automation Investment Details**

18 **Q23. How is the remainder of your testimony organized?**

19 A23. This section of my testimony discusses the following programs and projects within  
20 the Technology & Automation Pillar:

---

<sup>2</sup> Final Report of Utility Distribution Audit of DTE Energy, Part Two, p. 94, Case No. U-21305 (Sept. 23, 2024) (Audit Report).

<sup>3</sup> Audit Report, Part Two, pp. 41-43 ("The DGP's Grid Management investments are sound and reasonably moderate;" "The DGP's Distribution Planning investments respond to important developments that planning needs to address and will improve data and analytical tools, all for a moderate cost;" "The DGP plans for an effective and moderately priced set of Work Planning and Scheduling enhancements;" "measures to enhance data assembly and its use for Asset Management are sound and moderate in expected costs;" "The DGP's investments in Mobile Technology are moderate in amount and consistent with capabilities now prevalent in the industry.").

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|    |                                                                         |     |
|----|-------------------------------------------------------------------------|-----|
| 1  | a. Grid Automation.....                                                 | 15  |
| 2  | i. Distribution Automation .....                                        | 17  |
| 3  | ii. Grid Automation Telecommunications .....                            | 27  |
| 4  | iii. Conservation Voltage Reduction and Volt-Var Optimization (CVR/VVO) |     |
| 5  | Program.....                                                            | 42  |
| 6  | iv. Distribution Sensing and Monitoring (including Line Sensors).....   | 45  |
| 7  | v. Non-Wire Alternatives Pilots.....                                    | 48  |
| 8  | vi. Grid Edge Insights and New Technology.....                          | 59  |
| 9  | b. Operational Technology.....                                          | 62  |
| 10 | i. Grid Management .....                                                | 64  |
| 11 | 1. SOC Modernization Project – Alternative System Operations Center     |     |
| 12 | (ASOC) .....                                                            | 66  |
| 13 | 2. Advanced Distribution Management System (ADMS): Distribution         |     |
| 14 | Management System (DMS)/Outage Management System (OMS).....             | 68  |
| 15 | 3. ADMS Enhancements.....                                               | 70  |
| 16 | 4. Other Modernize Grid Management .....                                | 73  |
| 17 | 5. Meter Improvements .....                                             | 78  |
| 18 | 6. Customer Power Status Visibility Program (CPSV) .....                | 79  |
| 19 | 7. Operational Technology and Error Free Communication (EFC) .....      | 86  |
| 20 | 8. FLISR Implementation .....                                           | 89  |
| 21 | 9. Distributed Energy Resources Management System (DERMS) .....         | 94  |
| 22 | 10. Substation Cybersecurity Program .....                              | 100 |
| 23 | 11. Automation Configuration Database .....                             | 101 |
| 24 | ii. Distribution Planning.....                                          | 103 |
| 25 | 1. Network Management System (NMS).....                                 | 105 |
| 26 | 2. Load Forecasting & Analytics .....                                   | 110 |
| 27 | 3. Interconnection Process Enablement .....                             | 113 |
| 28 | 4. Hosting Capacity Enablement.....                                     | 115 |
| 29 | 5. Power Quality Analysis Program.....                                  | 116 |
| 30 | 6. Substation and Structural Design Tool Upgrades Program .....         | 118 |
| 31 | 7. Distribution Planning Program .....                                  | 119 |
| 32 | iii. Work Management and Scheduling .....                               | 121 |
| 33 | 1. Primary Service Orders Replatform.....                               | 122 |
| 34 | 2. External Crew Efficiency.....                                        | 124 |

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|    |                                                     |     |
|----|-----------------------------------------------------|-----|
| 1  | 3. Substation Report and Process Enhancements ..... | 128 |
| 2  | 4. Vegetation Management Replatform .....           | 129 |
| 3  | 5. Mobile Time Sheets .....                         | 131 |
| 4  | 6. Work Management and Scheduling Upgrades .....    | 132 |
| 5  | iv. Asset Management.....                           | 135 |
| 6  | 1. Asset Failure Analytics .....                    | 135 |
| 7  | 2. Cable Failure Analytics.....                     | 137 |
| 8  | 3. ESRI Utility Network Proof of Concept.....       | 138 |
| 9  | 4. ESRI Utility Network Model Upgrade .....         | 140 |
| 10 | 5. LIDAR and Imagery Analysis Platform .....        | 142 |
| 11 | 6. ADMS/GMS Hardware .....                          | 144 |
| 12 | v. Mobile Technology .....                          | 145 |
| 13 | 1. Mobile Tools Expansion .....                     | 146 |
| 14 | 2. ADMS: DMS/OMS Mobile Tool .....                  | 149 |
| 15 | 3. Enhance and Expand Cybersecurity .....           | 151 |
| 16 | 4. Mobile Equipment Replacement.....                | 153 |
| 17 | 5. Mobile Technology .....                          | 153 |

18

19      **a. Grid Automation**

20      **Q24. Earlier in your testimony you stated that Grid Automation focuses on the**  
 21      **infrastructure needed to support the efficient control and operation of a**  
 22      **modern distribution grid. Can you explain how investing in Grid Automation**  
 23      **impacts the ongoing safe and reliable operation of the grid?**

24      A24. Grid Automation is a vital component of DTE Electric's grid modernization  
 25      strategy. The Company's Grid Automation investments will maintain and improve  
 26      grid reliability, facilitate grid planning, and support integration of DERs.

- 27              • Reliability: Grid automation improves the reliability of the power grid by
- 28              enabling real-time monitoring, control, and in many cases automatic or

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1 remote rapid response to faults and abnormalities. It reduces outage  
2 durations, improves fault detection, and enhances grid resilience.

3 • Grid operations and planning: Grid Automation also provides valuable data  
4 and insights for grid planning and expansion. With automation, DTE  
5 Electric can adapt instantly to changes in energy consumption and  
6 generation (including renewable resources), better accommodate the load  
7 growth from electric vehicles, and integrate other new technologies into the  
8 grid. This flexibility supports an improved grid today and prepares the grid  
9 to successfully meet future energy demands and technological  
10 advancements.

11 • DER integration: The distribution grid is increasing in complexity as the  
12 result of growing bi-directional flow of power from the integration of  
13 renewable generation resources. Grid automation plays a crucial role in  
14 managing the variability and intermittency of renewable energy generation.  
15 It enables the ability to balance supply and demand, optimize energy flows,  
16 maintain grid stability, and facilitate the seamless integration of renewable  
17 energy into the grid.

18

19 **Q25. Where does the Company provide additional details of the Grid Automation**  
20 **capital investments?**

21 A25. The details of the capital investment in this category are provided in the following  
22 exhibits and schedules:

- 23 • Exhibit A-12, Schedule B5.4, pages 14-15; and  
24 • Exhibit A-23, Schedule M7.

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1 **i. Distribution Automation**

2 **Q26. What is Distribution Automation?**

3 A26. The Distribution Automation Program within Grid Automation uses digital field  
4 sensors and switches along with advanced control and communication technologies  
5 to automate or remotely control feeder switching, monitor voltage and equipment  
6 health, and manage voltage and reactive power. Without remote switches, the  
7 alternative option is for a crew to be dispatched to manually open or close a switch.  
8 In addition to the field resources cost, this results in a delay in operating the switch,  
9 which could cause or extend outages as well as other grid impacts. The benefits of  
10 these technologies are well documented and recognized. For example, the  
11 Department of Energy (DOE) highlighted that 16 utilities over a three-year period  
12 observed a reduction of 146 million customer minutes of interruption through the  
13 implementation of Distribution Automation.<sup>4</sup> The DOE concluded more generally  
14 that “DA technologies provided advanced capabilities for operators to detect,  
15 locate, and diagnose faults. Remote fault indicators, relays, and reclosers provide  
16 access to real-time data on key feeders, which when delivered to a fully functional  
17 DMS, can help operators accurately determine causes and locations of faults and  
18 the extent of outages when they occur.”<sup>5</sup>

---

<sup>4</sup> Office of Electricity Delivery and Energy Reliability, U.S. Department of Energy, *Distribution Automation: Results from the Smart Grid Investment Program* (2016), [https://www.energy.gov/sites/prod/files/2016/11/f34/Distribution%20Automation%20Summary%20Report\\_09-29-16.pdf](https://www.energy.gov/sites/prod/files/2016/11/f34/Distribution%20Automation%20Summary%20Report_09-29-16.pdf).

<sup>5</sup> Office of Electricity Delivery and Energy Reliability, U.S. Department of Energy, *Distribution Automation: Results from the Smart Grid Investment Program*, at pp. 20-21 (2016), [https://www.energy.gov/sites/prod/files/2016/11/f34/Distribution%20Automation%20Summary%20Report\\_09-29-16.pdf](https://www.energy.gov/sites/prod/files/2016/11/f34/Distribution%20Automation%20Summary%20Report_09-29-16.pdf).

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1 **Q27. How has the Company's strategy for Distribution Automation evolved over**  
2 **the last few years?**

3 A27. The Company started developing its 4.8<sup>6</sup> kV Circuit Automation program, which  
4 later became known as Distribution Automation, in 2021. After its review of outage  
5 and restoration events during severe storms that impacted the Company's service  
6 territory in early 2023, the Company concluded that the limited amount of  
7 automation across its system impeded its ability to swiftly restore services to  
8 customers during large storm events, and that extensive circuit automation would  
9 significantly improve reliability. At the same time, improvements in the available  
10 technologies for reclosers and telecommunications and the additional functionality  
11 that was part of the Advanced Distribution Management System (ADMS) permitted  
12 the Company to leverage (view, coordinate, and control) and more effectively use  
13 these technologies. Based on these conclusions the Company broadened its  
14 Distribution Automation Program to improve grid reliability.

15

16 **Q28. What is the primary scope of the Company's Distribution Automation**  
17 **Program?**

18 A28. The Distribution Automation Program focuses on pole top recloser deployments  
19 that are defined and discussed below. These include: (a) installation of Supervisory  
20 Control and Data Acquisition (SCADA) enabled reclosers on larger circuits with  
21 more than 400 customers to enable, at a minimum, one midline recloser and a  
22 SCADA enabled tie point; (b) installation of a recloser near the start of the overhead  
23 portion of a circuit for all ungrounded 4.8 kV circuits to enable ground detection

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<sup>6</sup> 4.8 kV is an ungrounded, delta configuration, circuit voltage that was an original DTE Electric standard and applied for several decades.

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1 and isolation; and (c) installation of reclosers near the start of the circuit on 13.2  
2 kV circuits that currently do not have SCADA enabled circuit breakers in the  
3 substation.

4

5 **Q29. What safety benefits do reclosers provide for the public and DTE Electric**  
6 **crews in terms of ground detection and isolation?**

7 A29. A ground on a 4.8 kV Delta circuit is a potential indicator of an energized wire  
8 condition that in some circumstances could pose a safety hazard to the public. The  
9 Distribution Automation Program includes start of circuit reclosers that provide  
10 new capability to detect when a ground occurs on a circuit and the ability to isolate  
11 the grounded circuit. Currently, when a ground alarm appears on a circuit, a  
12 substation operator is dispatched to the substation and manually identifies which  
13 circuit has a ground, then a field crew is sent to locate the ground and isolate. With  
14 the ability to automatically identify this condition, the potential hazard can be  
15 detected and deenergized much more quickly and efficiently through automated  
16 isolation, quickly eliminating the risk associated with the downed wire. Addressing  
17 these potential hazards automatically not only reduces the potential safety risk  
18 sooner but enhances restoration efficiency by allowing resources previously used  
19 to isolate energized wire-downs to instead be directed to restoration activities.

20

21 **Q30. Can you explain in further detail the reliability benefits that pole top reclosers**  
22 **provide?**

23 A30. Pole top reclosers, such as the G&W Electric Viper recloser used in this program,  
24 offer a variety of capabilities needed for distribution automation, including the  
25 ability to isolate outages into smaller sections and the ability to reroute power

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1 around damage. Reclosers installed at midpoints on a circuit will operate when a  
2 fault is detected and isolate the outage to smaller area, impacting fewer customers.  
3 Reclosers installed at a tie point on the end of a circuit provide the ability to  
4 reconfigure circuits and reroute power around damaged sections by connecting to  
5 adjacent circuits. This device is also used to provide advanced protection  
6 capabilities, such as ground detection and isolation, and circuit level SCADA  
7 monitoring and control to the System Operations Center.

8

9 **Q31. What other investments does the Distribution Automation Program include?**

10 A31. Beyond the pole top reclosers, some general distribution construction may be  
11 needed to create tie points on distribution circuits and to support capacity and  
12 voltage during circuit reconfiguration. The Distribution Automation Program also  
13 includes investments in: (a) the construction of the necessary overhead equipment  
14 to create and enable load shifts between circuits; (b) the integration of devices and  
15 technology within the Advanced Distribution Management System (ADMS) to  
16 allow for the future application of Fault Location, Isolation, and Service Restoration  
17 (FLISR) with the new and existing devices; (c) ground fault detection and isolation  
18 on the 4.8 kV system; (d) SCADA monitoring and control of all general-purpose  
19 distribution circuits; (e) advanced sectionalizing devices like trip savers; and (f)  
20 improved fault isolation and increased remote restoration capabilities to improve  
21 reliability. Taken together with the reclosers, the Distribution Automation Program  
22 improves grid safety and reliability for the Company and its customers.

23

24 **Q32. Did the Audit address the Company's Distribution Automation Program?**



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1 A32. Yes. The Audit recognized the benefits of the Company installing more reclosers  
2 to improve grid safety and reliability and generally supports the Company's plan  
3 for this effort. The Audit's recommended timing for deployment of these  
4 investments differs from the Company's plan outlined in the 2023 Distribution Grid  
5 Plan (DGP) filed in Case No. U-20147 by shifting the Company's proposed recloser  
6 installation rates out further in the DGP timeline to allow for more information to  
7 be gathered as to the optimal penetration rate based on installed reclosers'  
8 contributions to reliability.<sup>7</sup> The Company disagrees with the Audit  
9 recommendation to slow down the automation program, as doing so would delay  
10 realization of the already identified safety and reliability improvement benefits, but  
11 agrees to continue to identify and review the expected reliability benefits of the  
12 program and prioritize the circuit deployment accordingly. Notably, the Audit  
13 concluded that reclosers to be installed in this program "are of the same type  
14 [Liberty] recommend[s] for accelerated installation at substation exit points. The  
15 limitations addressed in this recommendation should not serve to constrain those  
16 safety-driven installations."<sup>8</sup>

17

18 **Q33. Did the Commission provide any guidance for the Company's continued**  
19 **evolution of its Distribution Automation program in the 2024 ERC, Case No.**  
20 **21534?**

21 A33. In approving recovery of the vast majority of the DTE Electric's capital  
22 expenditures for Distribution Automation in the Case No. U-21534 Order, the

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<sup>7</sup> Case No. U-21305, [068cs00000AyaNpAAJ](#), Audit Report, Part Two, pp. 92-94.

<sup>8</sup> Case No. U-21305, [068cs00000AyaNpAAJ](#), Audit Report, Part Two, p. 94.

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1 Commission noted that the Company is “working toward a BCA for DA moving  
2 forward” and stated that it looks forward to those results.<sup>9</sup>

3

4 **Q34. Did the Company complete a BCA for the Distribution Automation**  
5 **investments supported by your testimony?**

6 A34. Yes. As noted above, the Company retained 1898 & Co. to conduct a BCA for the  
7 Distribution Automation program. Specifically, the BCA produced a quantified  
8 benefit/cost evaluation for investments made that provide reliability improvements  
9 and demonstrates that the cost savings from avoided customer outage minutes  
10 would be larger than the cost investment of recloser installations on identified  
11 circuits.

12

13 **Q35. Does the BCA support the Company’s proposed recloser installation rates?**

14 A35. Yes. As discussed further in Witness De Stigter’s testimony, the BCA concluded  
15 that the Company’s Distribution Automation program is a cost-effective investment  
16 solution to improve safety and reliability and that it provides significant benefits to  
17 customers. Witness De Stigter explains that the BCA shows that approximately  
18 64% of eligible circuits have reliability benefits in excess of costs for customers.  
19 Witness De Stigter noted that the Grid Automation Telecommunication program is  
20 needed to fully capture the benefits of this program; I discuss this program in the  
21 next section of my testimony.

22

23 **Q36. What is the scope of Distribution Automation investments already performed**  
24 **and planned in the instant case?**

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<sup>9</sup> Case No. U-21534 Order at p. 148 (Jan. 23, 2025).

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1 A36. Table 2 shows the number of circuits impacted and reclosers installed as part of the  
2 Distribution Automation program in 2023 and 2024, and the investments planned  
3 for 2025 and 2026.

4 **Table 2 Distribution Automation Work<sup>10</sup>**

| Item      | 2023 | 2024 | 2025 | 2026 |
|-----------|------|------|------|------|
| Circuits  | 196  | 148  | 316  | 480  |
| Reclosers | 210  | 352  | 742  | 741  |

5

6 **Q37. How have customers benefitted from Distribution Automation investments**  
7 **that the Company has made to date?**

8 A37. Recloser deployments avoided 9,747 customer interruptions and 3,683,945 outage  
9 minutes in 2024. These deployments have also provided 55 trouble isolations and  
10 3 ground isolations.

11

12 **Q38. What factors informed the Company's prioritization for Distribution**  
13 **Automation projects?**

14 A38. The Company uses the Global Prioritization Model (GPM) to evaluate the benefits  
15 of and rank Distribution Automation capital investments relative to other projects  
16 and programs. The factors used and calculation of GPM scores for investments are  
17 further covered in the direct testimony of Witness Kryscynski. The factors that  
18 drive Distribution Automation's relatively high GPM ranking include (a) the  
19 improved safety benefits associated with more rapid de-energizing of down wires,

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<sup>10</sup> The counts include actual work performed the costs of which are recoverable through both the Investment Recovery Mechanism (IRM) and base rates.

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1 (b) the reliability benefits associated with the reduced number of customer  
2 interruptions and the reduction of outage durations, and (c) the improved  
3 operational efficiencies associated with improved system monitoring and control.

4 **Q39. What amount of Distribution Automation program resources does the**  
5 **Company expect to dedicate toward the installation of safety focused**  
6 **reclosers?**

7 A39. The Company expects to dedicate approximately one third of the total capital  
8 investment allotted to the Distribution Automation program, through both rate case  
9 base rate investment approval and the IRM mechanism explained more fully by  
10 Witness Willis, toward the installation of start of circuit safety reclosers. If the  
11 Company's request is approved, DTE Electric would invest approximately \$25  
12 million in 2025, \$50 million in 2026, and \$55 million in 2027, on safety reclosers  
13 through a combination of the base rate approvals and the IRM mechanism. This  
14 plan would result in the majority of 4.8 kV overhead load carrying circuits  
15 completed with safety recloser installations in early 2028.

16

17 **Q40. How does the Company plan to prioritize circuits for Distribution Automation**  
18 **safety improvement investments going forward?**

19 A40. The Company will prioritize start of circuit recloser installations intended to  
20 quickly isolate and deenergize wiredown events by analyzing current circuit data  
21 and historical wiredown events to focus on the greatest improvement opportunities.  
22 The factors and weighting included in this analysis on 4.8 kV circuits are: (1) five-  
23 year average wiredown events (60%); (2) schools served by the circuits (20%); and  
24 (3) customers per overhead circuit mile (20%). To achieve the efficiencies gained

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1 through permitting, design, and construction, the Company will analyze all 4.8 kV,  
2 overhead, and normal customer serving circuits collectively at each substation.

3

4 **Q41. What are the estimated safety improvements from Distribution Automation**  
5 **investments to install a recloser at the start of a 4.8 kV delta circuit in 2025**  
6 **and 2026?**

7 A41. Wiredowns on the 4.8 kV delta system can in some cases remain energized, posing  
8 a potential safety risk to the public. Circuits planned for safety enhancement in 2025  
9 and 2026 have seen an average of 11 and 10 downed wires per year between 2020  
10 and 2024, respectively. After recloser installations, these circuits will have a  
11 dedicated ground isolation recloser to mitigate potential energized downed wires.

12

13 **Q42. How does the Company plan to prioritize circuits for Distribution Automation**  
14 **reliability improvement investments going forward?**

15 A42. The Company will prioritize reliability recloser installations, which are intended to  
16 sectionalize and minimize the number of customers impacted by an outage and  
17 restore customer service through automatic switching between circuits, by  
18 evaluating the substations (aggregate of circuit results) with the highest BCA score  
19 as provided by the Witness De Stigter analysis described above. Additionally, the  
20 Company will apply an Environmental Justice (EJ) scoring component to the  
21 prioritization list in a similar methodology used in the GPM. The details of this  
22 application are provided in the testimony of Company Witness Kryscynski. Similar  
23 to the application of start of circuit reclosers, to achieve the benefits of efficiencies  
24 gained through permitting, design, and construction, the Company will analyze all  
25 overhead and normal customer serving circuits collectively at each substation.

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1 **Q43. What are the estimated reliability benefits associated with the Distribution**  
2 **Automation investments planned for 2025 and 2026?**

3 A43. Estimated benefits associated with the 2025 and 2026 program's investment are  
4 detailed in the reliability model supported by Witness Kryscynski.

5  
6 **Q44. What would be the impacts if the Company did not make the proposed**  
7 **Distribution Automation capital investments?**

8 A44. The detection, isolation, and operation of energized down wires would continue at  
9 the current rate without fully utilizing the available technology to improve this  
10 process and improve safety. Additionally, the relatively rapid reliability benefits  
11 that were demonstrated by the BCA would not be realized for customers.

12  
13 **Q45. Are any Distribution Automation investments included in the Infrastructure**  
14 **Recovery Mechanism (IRM)?**

15 A45. Yes. The Company's Distribution Automation investments are partitioned between  
16 recovery through base rates and the Company's authorized IRM mechanism. For  
17 the historical, bridge and test periods in the instant case, Exhibit A-12 Schedule  
18 B.5.4.8 shows the partition between the base rates requested in Exhibit A-12  
19 Schedule B5.4 and authorized IRM amounts shown in Exhibit A-33 Schedule X1.  
20 Distribution Automation investments beyond 2026, as described below, are  
21 proposed for inclusion in the IRM and shown in Exhibit A-33 Schedule X1.  
22 Company Witness Willis discusses the background of the IRM and supports the  
23 inclusion of investments in the IRM. The Distribution Automation circuit  
24 prioritization in the IRM will follow the method mentioned earlier in my testimony,  
25 which includes using the EJ multiplier to adjust the benefit cost ratio.

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1 **Q46. What are the Company's expectations for investment in Distribution**  
2 **Automation beyond the projected test year?**

3 A46. The Company will continue to need to invest in Distribution Automation beyond  
4 the test period covered in this case. The forecast of required investment beyond  
5 2026 is:

- 6 • 2027: \$165 million
- 7 • 2028: \$250 million
- 8 • 2029: \$320 million

9 This reflects the full expected investment for the program from 2027 to 2029 and  
10 is included in this case as the basis for the Company's IRM request supported by  
11 Company Witness Willis.

12

13 **ii. Grid Automation Telecommunications**

14 **Q47. What is Grid Automation Telecommunications?**

15 A47. Grid Automation Telecommunications refers to the use of telecommunications  
16 technology as an essential enabling component in the automation of electrical  
17 power grids. It involves the integration of communication systems with power  
18 distribution networks to enable real-time monitoring, control, and management of  
19 grid operations.

20 **Q48. What is the role of telecommunications in supporting a more safe, reliable**  
21 **grid?**

22 A48. The telecommunications network is the backbone system that connects the  
23 distribution automation equipment in the field to the System Operations Center  
24 (SOC). The network enables two-way communication that provides the SOC with

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1 real-time visibility into grid conditions and the ability to remotely operate grid  
2 devices. An advanced telecommunications infrastructure plays a crucial role in grid  
3 automation by providing reliable and secure communication channels for data  
4 exchange between grid devices such as sensors, meters, switches, and control  
5 centers. These secure and reliable data exchanges enable programs like Distribution  
6 Automation, Conservation Voltage Reduction (CVR), Volt-Var Optimization  
7 (VVO), Advanced Metering Infrastructure (AMI), and demand response, along  
8 with day-to-day grid management and other core components and advanced  
9 applications described in the 2023 DGP.

10

11 **Q49. Can you describe the typical structure of an electric utility telecommunications**  
12 **network?**

13 A49. An electric utility telecommunications network structure typically consists of  
14 multiple components that work together to facilitate communication and data  
15 exchange within the utility's infrastructure. These components include the  
16 following key elements:

- 17 • Backhaul network: The backhaul network serves as the central  
18 communication backbone of the utility's infrastructure, connecting different  
19 sites such as power plants, substations, and control centers. It handles high-  
20 capacity data transmission and supports critical applications for monitoring,  
21 control, and device management, and incorporates the highest level of cyber  
22 security controls and network management. Through 2026, the Company's  
23 Grid Automation Telecommunications investments are focused on  
24 expanding the backhaul network to connect the critical infrastructure  
25 locations with a secure, high bandwidth and resilient solution.



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- 1 • The last mile network: The last mile network connects end-use devices,  
2 such as sensors, meters, and monitoring equipment, to the backhaul  
3 network. It consists of wireless technology such as microwave links, radio  
4 frequency (RF) networks, and cellular networks, to establish  
5 communication links between different sites. Wireless infrastructure  
6 provides flexibility and scalability in extending network coverage and  
7 provides a secure and manageable interface between devices and the  
8 backhaul network.

9  
10 The electric utility telecommunications network typically incorporates multiple  
11 technologies, such as fiber, wireless systems, elevated structures, switches, and  
12 routers, that work together. Each of these technologies needs ongoing supporting  
13 investment to maintain an integrated system that allows for the seamless flow of  
14 information, enables remote monitoring and control of the grid, and permits  
15 performance of cybersecurity threat monitoring and security updates.

16  
17 **Q50. Can you describe the current state of the Company's Grid Automation**  
18 **Telecommunication network?**

19 A50. While the current telecommunication network effectively served the less complex  
20 grid of previous decades, DTE Electric's existing telecommunication network  
21 consists of a combination of equipment and technologies, including fiber,  
22 microwave, leased phone lines, and radio, some of which are legacy systems  
23 reaching end of life. Legacy, obsolete end of life systems are challenging to  
24 maintain as they experience failures and spare parts become unavailable.  
25 Additionally, the Company needs to replace such systems that are incapable of

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1 supporting the new smart grid operations required for remote management of  
2 devices and the transition of existing communications assets.

3

4 The current network does not fully connect all field devices to the Electric System  
5 Operations Center (ESOC). Many devices currently on the Company's electrical  
6 system, including some pole-top and substation equipment, are either not connected  
7 for remote monitoring and control, or are connected through a patchwork of  
8 communication networks and technologies that have varying capabilities, are not  
9 fully integrated, and in many cases cannot provide resiliency due to their  
10 architecture. As a result, the devices do not fully support more timely outage  
11 restorations that would be available with remote monitoring and control.

12

13 At the center of the telecommunications system, the Company currently relies on a  
14 fiber ring that was originally designed to connect only those data centers and  
15 transmission stations located on towers along transmission corridors. When the  
16 fiber ring was developed and installed in the 1990s, based on the grid controls  
17 available at the time, the design scope did not include the future need or capability  
18 to connect the more modern distribution resources coming to the grid today.

19

20 Additionally, the original telecommunications network that is part of the backhaul  
21 network does not currently extend to all critical assets including stations,  
22 communication towers, and service centers. As a result, many critical locations  
23 currently are connected through multiple legacy technologies that do not meet  
24 evolving telecommunications needs. The legacy telecommunications technologies  
25 also lack sufficient capability to provide the bandwidth speed, capability, and

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1 reliability necessary to stabilize delivery and respond to the data being transmitted  
2 by those modern distribution resources. A key driver of the Grid Automation  
3 Telecommunications investments is to address these limitations by expanding the  
4 backhaul network with additional fiber as proposed in this case. This effort will  
5 result in a more resilient, secure, and higher performance network with greater  
6 capabilities that is easier to maintain and more effectively supports current and  
7 future automation goals.

8

9 **Q51. Are there other communication paths, other than fiber, available that**  
10 **effectively support the transfer of information for the identified critical sites?**

11 A51. No. As described above, the sites that are critical to the distribution system and  
12 transfer of data must be supported by a communication system that can provide the  
13 necessary bandwidth, security, and reliability. These sites include monitoring  
14 devices and sensors that generate extensive amounts of sensitive and critical system  
15 data to be transferred back to the ESOC, including system loading, system voltage  
16 values, and security camera footage at the highest risk sites. Additionally, many of  
17 the sites also require a reliable and secure communication path from the SOC to  
18 accurately execute critical remote operations of the system that can minimize  
19 customer outages and allow crews to work safely.

20

21 The communication bandwidth that is required for these critical sites can be large  
22 and include locations requiring terabytes of data transfer for telemetry recording  
23 and other use cases such as physical security. Also important is the latency of the  
24 data transfer to ensure safe and accurate control and coordination of the system,  
25 with some use cases such as communications-based protection schemes requiring

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1 guaranteed latencies of less than 50 milliseconds and many other automation use  
2 cases requiring less than 250 milliseconds. Without the availability of the necessary  
3 communication bandwidth and latency, the SOC will not be able to receive all of  
4 the information that these devices were installed to provide or reliably control them  
5 to achieve their operational benefits. This would result in the limiting or complete  
6 loss of critical system visibility and control that the SOC relies on to operate the  
7 system safely and reliably. Utilizing a communications service provider typically  
8 comes with pre-defined limits to the data usage that is available for the specific  
9 service locations. When a service exceeds the pre-defined data usage, the provider  
10 can apply additional fees to the service, increasing overall costs, or limit the amount  
11 of data able to be transferred from each service location. By limiting the amount of  
12 data able to be transferred or increasing latency, due to either passing a pre-defined  
13 monthly threshold or high-volume usage in the area, system visibility and control  
14 is also limited or unavailable.

15

16 Due to the sensitive nature of the information that is transferred between the  
17 monitoring and switching devices in the field to the SOC, advanced security of the  
18 system is required. Especially critical to protect are the communications between  
19 the SOC and the switching devices in the field. If this communication security were  
20 compromised, someone could gain control of the system and implement either  
21 targeted or widespread system outages by remotely operating DTE Electric  
22 switching devices. Communications service providers typically provide some level  
23 of security, but it would not be sufficient to meet the standards necessary to protect  
24 customers and the life critical electric service that the Company is depended upon  
25 to provide. Vendor services provide broad security to maintain the overall network

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1 availability but rely on customers to provide their own monitoring, alarming,  
2 intrusion detection, encryption, and mitigation mechanisms for their own traffic.  
3 These vendor services would therefore not reduce the investment the Company  
4 would continue to make in Cyber operations. Additionally, these systems would  
5 require additional investments for firewalls and data security hardware at each end  
6 point where public and private networks come together.

7

8 **Q52. What conclusions do you draw from the considerations discussed above?**

9 A52. The critical nature of the system visibility and control for the SOC drives the  
10 necessity for a reliable and robust communication path. As previously discussed,  
11 the ability to have real-time visibility and control of the system impacts its safety  
12 and reliability for the crews working on it and the customers DTE Electric serves.  
13 Fiber communications would need an interruption on multiple locations of the  
14 backbone ring to interrupt the data transfer, which makes fiber a prudent choice for  
15 the most critical assets and locations. Wireless communication could be sufficient  
16 for less critical locations that impact fewer customers and would not contribute to  
17 widespread system issues if communication was interrupted. A wireless system that  
18 experiences intermittent connectivity issues, due to signal issues or maintenance  
19 (planned or unplanned), limits the availability of the critical information and control  
20 of the electrical system. During widespread outages that occur when larger storms  
21 pass through the Company's service territory, wireless bandwidth may become  
22 extremely limited and unavailable to anyone other than first-responder services.  
23 This could lead to critical delays in understanding where the outages are on the  
24 system and the switching that is necessary to restore large numbers of customers at

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1 a time when they need service most. Leasing fiber also subjects the Company to  
2 planned and unplanned outages by the service provider.

3

4 **Q53. Has the Company investigated and compared the options to install and utilize**  
5 **a fiber backbone for its critical assets and locations?**

6 A53. Yes. The Company has received quotes from multiple fiber vendors to build and  
7 lease their fiber to connect to locations DTE Electric has identified. A comparison  
8 of the quotes to build new fiber and complete the connection points identified shows  
9 that DTE Electric's contractors can build these paths at a lower cost per mile than  
10 area providers. The comparison also demonstrates that leasing options for  
11 equivalent capacity and capability are substantially more costly as the vendors must  
12 charge for recovery of the new fiber construction in addition to ongoing operations.  
13 Even if they have some infrastructure in the area, it may not connect between  
14 locations in a way that would enable the Company's use cases, necessitating  
15 extensive construction and multiple security demarcation points that would not be  
16 present with DTE Electric constructed and operated fiber. Furthermore,  
17 interruptions due to planned and unplanned outages from these providers would  
18 increase costs and communication continuity risks with limited visibility into  
19 scheduling and a potentially lower priority for restoration by a third party as  
20 opposed to the Company.

21

22 **Q54. What components of the Grid Automation Telecommunications investment**  
23 **plan, as shown on Exhibit A-12, Schedule B5.4, page 14, line 5, were completed**  
24 **in 2023 and 2024?**

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- 1 A54. During 2023, the Company completed and made progress on the following work  
2 totaling 350 miles which includes:
- 3 • Completion and commissioning of the Dearborn to Monroe fiber line and  
4 the connection of both Fermi and Monroe power plant stations and facilities  
5 to the fiber network, this work also included routes to the Newport service  
6 center and Downriver substation locations;
  - 7 • Substantial completion of routes on the East side of Detroit and up the I-94  
8 corridor; and
  - 9 • Progress on routes to reach Howell service center and the fiber ring from  
10 Monroe to Ann Arbor to provide resiliency to the Dearborn to Monroe line.
- 11 During 2024, the Company completed and made progress on the following work  
12 totaling 480 miles which includes:
- 13 • Completion of construction of routes north of Port Huron Across the I-69  
14 Corridor and connection to North Area Energy Center;
  - 15 • Completion of Routes on the I-96 and I-94 Corridor in western Wayne  
16 County and Washtenaw County;
  - 17 • Continued progress on installations on the East and West side of the City of  
18 Detroit;
  - 19 • Substantial completion of routes in Northern Oakland County;
  - 20 • Completion of the fiber ring from Monroe to Ann Arbor;
  - 21 • Partial completion of routes north of Ann Arbor and Downriver; and
  - 22 • Design and procurement of electronics to light up routes that have finished  
23 fiber construction and to connect substation end points with the existing  
24 wireless mesh network end points to improve bandwidth and reliability.

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1 **Q55. What is the Company's long-term plan to enhance and modernize Grid**  
2 **Automation Telecommunications?**

3 A55. The Company's Grid Automation Telecommunications investment plan consists of  
4 three general phases: (1) installation and commissioning of the fiber backbone to  
5 critical sites will continue through 2026; (2) near-term investments in 2026 through  
6 2028 will focus on extending the backhaul network to next tier locations that cannot  
7 be sufficiently served by existing deployed technologies or currently do not have  
8 communications capabilities; (3) future investments beyond 2028 will focus on  
9 building out the last mile network to pole top devices.

10

11 **Q56. Has the Company identified any additional benefits to an expansion to the**  
12 **fiber network?**

13 A56. Yes. Though investments are not proposed and requested in this instant case, the  
14 Company is investigating the future scenario and customer benefits of a DTE  
15 Electric owned and operated private Long-Term Evolution (LTE)<sup>11</sup> network. The  
16 backhaul fiber ring that is necessary for the communication requirements of the  
17 Company's critical sites would also serve as a solid base for the infrastructure  
18 needed to support a privately run LTE network.

19 **Q57. What did the Commission determine with regard to Grid Automation**  
20 **Telecommunications in Case No. U-21534?**

21 A57. In the Order in Case No. U-21534, the Commission approved recovery of the  
22 Company's historical and bridge year spending for Grid Automation

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<sup>11</sup> LTE, which stands for Long Term Evolution, is a standard for wireless broadband communication for cellular mobile devices and data terminals and is a key technology for the fourth generation of mobile networks. The Company's investigation will not be limited to 4G/5G technology, and an appropriate solution will be selected to provide for effective management of the technology lifecycle.



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1 Telecommunications. The Commission disallowed DTE Electric's projected test  
2 year capital expenditures for 2025 (\$15 million) based on its finding of insufficient  
3 evidence in the record to support the projected spend. The Commission clarified  
4 that "for future Grid Automation Telecommunications investments, the  
5 [C]ompany's BCA or alternatives analysis should include both qualitative  
6 comparisons between available technologies and quantitative cost comparisons."<sup>12</sup>  
7 The Commission also noted that "the [C]ompany should provide a more  
8 comprehensive description of the total scope of this project/program moving  
9 forward."<sup>13</sup>

10

11 **Q58. Has the Company developed an alternative analysis with quantitative cost**  
12 **comparisons to supplement the qualitative comparisons discussed earlier in**  
13 **your testimony?**

14 A58. Yes. The Company has worked with 1898 & Co. to develop a BCA that evaluates  
15 multiple scenarios for a least cost comparison to help determine a long-term  
16 comprehensive program plan<sup>14</sup>. That effort is explained in more detail by Witness  
17 De Stigter of 1898 & Co. The five scenarios that were evaluated and compared  
18 include:<sup>15</sup>

19 1. Continuing the current path with several communication methods,  
20 including maintaining the existing field communications network (Tropos  
21 network<sup>16</sup>);

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<sup>12</sup> Case No. U-21534 Order at p. 154.

<sup>13</sup> Case No. U-21534 Order at p. 154.

<sup>14</sup> Case No. U-21860, Exhibit A-28, Schedule R3.

<sup>15</sup> Exhibit A-28, Schedule R3, p.21, Table 1-1

<sup>16</sup> TROPOS is the Meter Mesh Network used to aggregate communications from the AMI meters to the data centers.

Line  
No.

- 1 2. Utilizing exclusively public LTE providers with the current installed
- 2 devices;
- 3 3. Utilizing exclusively public LTE providers with the installation of
- 4 additional devices;
- 5 4. Developing a Company owned, private LTE, with the current installed
- 6 devices; and
- 7 5. Developing a Company owned, private LTE, with the installation of
- 8 additional devices.

9  
10 **Q59. Were any other alternative analyses conducted for the current fiber**  
11 **deployment?**

12 A59. Yes, in addition to evaluating the BCA for each route to determine if it aligned with  
13 the benefits in the overall plan, the Company conducted cost benchmarking on both  
14 alternative construction vendors for self-build fiber and the option to lease fiber  
15 from a third party. As shown in Case No. U-21534 and Case No. U-21860, Exhibit  
16 A-19, Schedule I1.2, bids were solicited for each route, as part of a self-build, and  
17 this has led to a 30% reduction in costs. When evaluating lease options, self-build  
18 was found to be approximately two to four times less expensive for the initial term  
19 Monthly Recurring Costs before long-term servicing was included. In addition to  
20 the fiber routes that would need to be constructed by the vendors, investments  
21 would be needed for this option including the same onsite work at each end point,  
22 and the Company would have to install demarcation points, which would not be  
23 needed in a self-built option and finally, ongoing lease support costs.

Line  
No.

1 **Q60. Does the BCA support the Company's proposed investment in the Grid**  
2 **Automation Telecommunication program?**

3 A60. Yes. While Witness De Stigter utilizes preliminary analysis and costs, he  
4 demonstrates that the Private LTE / Fiber alternative provides the most benefits to  
5 customers in both capacity scenarios evaluated, including having benefits in excess  
6 of costs in both scenarios. In Witness De Stigter's Exhibit A-28, Schedule R3 for  
7 the expanded use case scenario, the Private LTE / Fiber alternative has a benefit  
8 cost ratio of 2.19. In other words, for every dollar of investment, customers will get  
9 2.19 dollars of benefit. For both the life-cycle cost evaluation and the benefit cost  
10 evaluation, this alternative provides the most benefits for customers as compared  
11 to the highest cost scenario of maintaining the existing network and all of its  
12 complex legacy mix of technologies. This supports the Private LTE / Fiber  
13 alternative as the preferred long-term telecommunication strategy for DTE Electric.

14  
15 **Q61. Based on the Grid Automation Telecommunications plan, what investments**  
16 **does the Company plan to make in 2025 and 2026?**

17 A61. The Company's 2025 and 2026 investments are shown in Exhibit A-12, Schedule  
18 B5.4, page 14, line 5.

19 Detailed below are the 2025 plans:

- 20 • Complete routes begun in 2024;
- 21 • Investments to replace leased lines in the Eastern thumb, coordinated with  
22 sub transmission relocations;
- 23 • Additional routes in the City of Detroit will begin construction and be  
24 coordinated with substation conversion and consolidation and the City of  
25 Detroit Infrastructure (CODI) program; and

Line  
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- 1 • Engineering and design of the electronics to connect the end point
- 2 substations to light up all constructed routes from end to end for critical
- 3 infrastructure and resiliency routes.

4 Detailed below are the 2026 plans:

- 5 • Complete infrastructure routes in Detroit, Southfield and Warren;
- 6 • Install electronics and routing equipment at critical sites and substations to
- 7 complete light up of infrastructure and resiliency routes; and
- 8 • Evaluate and install new routes with a priority based on the next most
- 9 critical infrastructure.

10

11 **Q62. If the Company does not pursue the development and implementation of a**  
12 **privately owned LTE network, are these investments still reasonable, prudent,**  
13 **and necessary?**

14 A62. Yes. As described previously, these investments in fiber backbone are justified and  
15 necessary for proper communication paths to critical assets and locations including  
16 SCADA, Asset Health monitoring, remote management, and physical security. It  
17 is prudent to complete these fiber communication paths as planned, regardless of  
18 the steps taken for future communication buildout to the remaining infrastructure  
19 sites. The additional explanation provided earlier in this testimony confirms that  
20 DTE Electric can build the fiber paths as a lower cost alternative than engaging  
21 service providers to build the paths and lease them, and that these investments  
22 would also support a lower cost alternative long-term plan to utilize private LTE.

23

24 **Q63. What are the impacts if the Company does not make these Grid Automation**  
25 **Telecommunications investments?**

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1 A63. If the Company does not make these investments, it will not be able to support the  
2 reliable, secure, and efficient transfer of data to and from the distribution system  
3 devices that is necessary to operate the grid with advanced smart technologies that  
4 are being developed and deployed as software and physical electrical system  
5 equipment. Without a reliable, secure, and sufficient communication path, new  
6 technology investments may not be able to achieve their expected system benefits.  
7 Critical data from devices capable of monitoring and reporting may not successfully  
8 reach the SOC and expected databases for real-time system conditions and accurate  
9 modeling. Continuing to maintain a patchwork of systems will be overall more  
10 costly while providing less future capability to support emerging uses. Devices  
11 designed to be remotely controlled by the SOC, or future modeling analytics  
12 (FLISR), would not receive commands to operate to improve coordination and  
13 customer outage restoration.

14

15 **Q64. Will the investments in the Grid Automation Telecommunications Program**  
16 **continue past 2026?**

17 A64. Yes. As I noted earlier in my testimony, in order to continue to support grid  
18 communications with the ongoing addition of field devices, automation, and future  
19 capabilities for emerging use cases, fiber installations are expected to continue  
20 beyond 2028. DTE Electric's plans for potential future investments include the  
21 integration of Private LTE (PLTE) or an advanced wireless system to connect to  
22 additional device locations and assets inside the service territory. This continuation  
23 of the grid telecommunications program installations to address the last mile  
24 devices is projected to run through the end of the decade.

Line  
No.

1 **iii. Conservation Voltage Reduction and Volt-Var Optimization (CVR/VVO)**

2 **Program**

3 **Q65. What are Volt-Var Optimization and Conservation Voltage Reduction?**

4 A65. Volt Var Optimization (VVO) is both a technology and a process used to manage  
5 system-wide reactive power flow to achieve one or more specific operating  
6 objectives, including reducing line voltage losses, managing circuit level voltage to  
7 support customer power quality, optimizing operating parameters, and optimizing  
8 power factors.

9  
10 Conservation Voltage Reduction (CVR) is a specific VVO technology designed to  
11 maintain customer voltage in the lower portion of the allowable voltage ranges  
12 under certain grid conditions, thus reducing system losses, peak demand, and  
13 energy consumption at a circuit level.

14  
15 CVR is achieved by utilizing communication and control to various electrical  
16 equipment including transformer load tap changers (LTC), overhead line  
17 regulators, and capacitor banks. In addition, DTE Electric uses SCADA monitoring  
18 devices and line sensors to ensure customer voltage levels are maintained in  
19 allowable voltage ranges.

20 **Q66. What is the CVR/VVO Program?**

21 A66. The CVR/VVO Program involves replacing end of life pole top capacitor controls  
22 with modern SCADA enabled controls that include sensors and asset health  
23 measurement. It also entails upgrades to selected substation Load Tap Changer  
24 (LTC) Controllers to coordinate with the pole top devices through the ADMS

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1 CVR/VVO control capabilities. ADMS CVR/VVO allows for pole top and LTC  
2 data to be analyzed in real time with a circuit model that computes voltage changes  
3 every few minutes and adjusts the device controls dynamically for each circuit to  
4 provide the optimal configuration as opposed to each device operating  
5 independently.

6

7 **Q67. What progress has DTE Electric made with the CVR/VVO Program to date?**

8 A67. DTE Electric successfully completed the installation of CVR/VVO technology on  
9 the distribution system on six pilot circuits in two substations in 2020 through 2022,  
10 which included installing ten new capacitor controls and upgrading substation LTC  
11 controls. The Company paused the program in 2023 and 2024 to align it with  
12 advancements in ADMS that would allow for the use of ADMS CVR/VVO  
13 modules for more efficient control in place of the local electronic control used in  
14 the pilot. Although the program was paused, in 2023 and 2024 the Company  
15 completed engineering, design, and the replacement of failed capacitors and  
16 capacitor controls with units that support CVR/VVO for 36 capacitor locations.

17 **Q68. How did the Commission respond to the investments in the CVR/VVO**  
18 **program in Case No. U-21534?**

19 A68. The Commission approved the Company's investments in the CVR/VVO program  
20 in the Case No. U-21534 Order<sup>17</sup>.

21

22 **Q69. What is the scope of investments included in Exhibit A-12, Schedule B5.4, page**  
23 **14, line 2 for the CVR/VVO Program for 2025 and 2026?**

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<sup>17</sup> Cost recovery for the Company's CVR/VVO investments was not contested in Case No. U-21534.

Line  
No.

1 A69. In 2025, the Company plans to upgrade 22 circuits. Circuit upgrades include the  
2 replacement of 50 capacitors and controls and two regulator control replacements,  
3 which will allow for ADMS monitoring and control of voltage through CVR/VVO  
4 modules. The scope of investments also includes targeted capacitor control  
5 replacements to address end of life capacitor controls that rely on time-based radio  
6 control. The manufacturer of the existing radio controls has determined them to be  
7 obsolete, creating a risk of unavailability of spare components for the radio  
8 transmitter. In 2026 DTE Electric plans to update an additional 40 circuits. Circuit  
9 upgrades include the replacement of 80 capacitors and controls and four regulator  
10 controls.

11

12 **Q70. What are the benefits of the CVR/VVO Program investment planned for this**  
13 **case?**

14 A70. The investments made through the CVR/VVO Program will permit DTE Electric  
15 to achieve energy savings that would not otherwise be possible by adjusting  
16 reactive power flow with VVO and reducing real and reactive power flow with  
17 voltage reduction from CVR. Customers will benefit from the energy savings,  
18 improved power factor, and better regulation of voltage.

19 Additionally, a number of end-of-life capacitor controls will be upgraded by  
20 replacing the existing capacitor controls with new SCADA-enabled controls to  
21 allow those units to be integrated into the CVR/VVO program in the future. The  
22 new capacitors will be able to be controlled by the ADMS VVO module and  
23 provide real-time optimization of the circuit voltage and reactive power. This will  
24 provide efficiency benefit to the circuit related to improved power factor, but the



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1 circuits they are on will not have the voltage reduced to gain extra energy efficiency  
2 savings from CVR.

3

4 In addition to distribution grid benefits, CVR/VVO is also considered a cost-  
5 effective generation alternative, as further discussed in the Company's past IRP in  
6 Case No. U-20471.

7

8 **Q71. What would be the consequences of not making the proposed CVR/VVO**  
9 **program capital investments?**

10 A71. If the Company did not execute the CVR/VVO program it would lose the  
11 opportunity to achieve the energy savings described above. Additionally, many end  
12 of life capacitor controls would not be replaced and would continue to operate sub  
13 optimally and without control from the ADMS. This would lead to lost  
14 opportunities for voltage and var optimization and condition-based maintenance of  
15 the capacitors. Additionally, not replacing the controls would result in fewer points  
16 of visibility for the ADMS SCADA system, leading to less knowledge of the system  
17 state for System Supervisors in the ESOC. This would mean incurring the cost of  
18 additional work orders, including physical site visits to assess system status,  
19 manually setting capacitors, and performing voltage optimization for switching.

20

21 **iv. Distribution Sensing and Monitoring (including Line Sensors)**

22 **Q72. What are Distribution Line Sensors?**

23 A72. Distribution Line Sensors are devices used to monitor the real time status of the  
24 distribution system and provide critical information to field personnel and system  
25 control room operators to help them better monitor and manage the grid.

Line  
No.

1   **Q73.   What is the scope of the Distribution Line Sensors Program?**

2   A73.   This program includes the installation of overhead system sensors used to detect  
3           outages and faults on the overhead and underground lines and send the data directly  
4           to the ADMS to speed restoration. These sensors also monitor power quality and  
5           fault data needed for real time load transfer analysis, fault locating, and system  
6           status. It also includes the installation of Underground Residential Distribution  
7           sensors for use in underground areas to quickly direct field crews to fault  
8           underground sections to improve isolation and restoration times. This program will  
9           also include a technology demonstration of new sensors intended to help monitor  
10          the system for broken pole and wire-downs, allowing dispatchers to better locate  
11          and differentiate between energized and deenergized wire-downs as well as downed  
12          electrical lines versus joint use wires.

13

14   **Q74.   What are the benefits of Distribution Line Sensors?**

15   A74.   Distribution line sensors are basically “the eyes and ears of the grid.” They support  
16          faster outage restoration by helping to identify and locate faults, which allows for  
17          the timelier dispatch of crews to the identified fault location. Line sensors located  
18          at manual switches, crossings or other operating locations indicate to the control  
19          room that a fault has occurred beyond the device and a crew will then be dispatched  
20          to the location. Crews will first restore portions of the circuit and then begin  
21          patrolling for the specific fault location from the line sensor location. Visual  
22          indication (Figure 1) on the line sensors also helps crews quickly identify faulted  
23          lines when they are in the field. Many line sensors also collect loading and voltage  
24          data that can be sent directly to the ADMS and fault information that can be used  
25          in the ADMS advanced distribution applications like FLISR, which contributes to

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1 reducing outage duration for customers. The line sensors work together with the  
2 telecommunications system, described earlier in my testimony, to provide power  
3 and fault information to the ESOC and engineering personnel via the ADMS  
4 system.

5  
6 **Figure 1 Distribution Line Sensor Visual Fault Indication**



7  
8 **Q75. What progress has DTE Electric made in this program?**

9 A75. During 2023, 370 underground (UG) line sensors and 100 overhead sensors were  
10 installed. Additionally, 300 pole sensors and 1,000 overhead line sensors were  
11 purchased for future installation. In 2024, 543 overhead line sensors were installed,  
12 and 300 pole sensors were installed to test sensor ability to detect wiredowns.

13  
14 **Q76. What is the scope of investments included in Exhibit A-12, Schedule B5.4, page**  
15 **14, line 4 for the Distribution Line Sensors Program for 2025 and 2026?**

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1 A76. In 2025 approximately 450 overhead sensors and 800 underground sensors will be  
2 installed. In 2026, another approximately 1,100 underground sensors will be  
3 deployed and 450 overhead sensors will be installed.  
4

5 **v. Non-Wire Alternatives Pilots**

6 **Q77. What are Non-Wire Alternatives?**

7 A77. As defined by the Commission, Non-Wire Alternatives (NWA) are “[a]n electricity  
8 grid investment or project that uses distribution solutions such as distributed energy  
9 resources (DER), energy waste reduction (EWR), demand response (DR), and grid  
10 software and controls, to defer or replace the need for distribution system  
11 upgrades.”<sup>18</sup> NWA have the potential to become economic alternatives compared  
12 to traditional infrastructure upgrades, in some cases delaying or preventing the need  
13 for more costly investment projects, and in some cases including renewable energy  
14 assets as part of the projects.  
15

16 **Q78. Can you describe the Company’s NWA Program?**

17 A78. Since 2018, in response to the Commission’s directive in the Case No. U-20147  
18 final order<sup>19</sup> and based on subsequent MPSC approvals, DTE Electric has  
19 progressed with the implementation of a set of NWA pilots that use alternative  
20 technologies to address circuits or substations with loading concerns to help delay  
21 or offset traditional system upgrades. As part of the program, the Company will  
22 analyze the results of pilots as they are completed to inform the execution of

---

<sup>18</sup> Case No. U-20147 Order at p. 11 (Aug. 20, 2020); Case No. U-21534 Order at p. 154, n. 25 (Jan. 23, 2025) (citing to 2020 Order).

<sup>19</sup> Case No. U-20147 Order at pp. 43-44 (“the Commission expects to be presented with ‘a robust suite of NWAs that may be evaluated for prudence as possible programs.’”).

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1 additional pilots. The pilots will also inform the Company's plan to incorporate  
2 NWA solutions into the distribution planning process along with traditional  
3 strategies for maintaining and improving the distribution system. The currently  
4 operational and planned pilots represent the building blocks for future NWA  
5 projects that may, for example, apply combinations of multiple NWA technologies.

6

7 **Q79. How will customers benefit from the NWA Pilot Program?**

8 A79. At a pilot-specific level, individual participating customers benefit from investment  
9 in the technologies used in targeted NWA solutions through lower energy bills due  
10 to EWR and enhanced DTE Electric rebates on energy saving products and  
11 services. More broadly, the Company expects that the pilots will validate economic  
12 impacts to help further refine its analysis of NWA as an alternative to traditional  
13 solutions.

14

15 **Q80. How many NWA pilots are included in the Program?**

16 A80. The Company is currently engaged with a suite of eight NWA pilots. The Company  
17 completed the Hancock Station pilot in December 2019. Seven NWA pilots are  
18 currently in development or undergoing implementation. I provide further details  
19 on each of the NWA pilots below.

20

21 **Q81. Did the Commission address the NWA projects in Case No. U-21534?**

22 A81. Yes, in its Case No. U-21534 Order the Commission supported the Company's  
23 recovery of costs associated with the O'Shea, Mobile Battery Trailer, Omega,  
24 Fisher, Port Austin, Veridian, and EV Charging Demonstrations and adopted a  
25 disallowance for the Adaptive Networked Microgrids Pilot due to uncertainty of

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1 federal funding for this project.<sup>20</sup> The Commission agreed with the Company that  
2 it should “continue to focus on [its] current NWA pilots to obtain results that will  
3 better inform the [C]ompany on how to scale its current NWA pilots and better  
4 identify opportunities that are suitable for NWAs with relevant findings  
5 incorporated into the [C]ompany’s DGP.”<sup>21</sup>

6

7 **Q82. Can you describe the NWA investments included in Exhibit A-12, Schedule**  
8 **B5.4, page 14, lines 6-11, 32 and 43?**

9 A82. The Hancock Pilot was completed and described in Case No. U-20836.<sup>22</sup> The  
10 remaining pilots are fully described in Exhibit A-12, Schedules B5.4.1 through  
11 B.5.4.7, and Exhibit A-23, Schedule M7.

12

13 **Q83. Can you elaborate on the technologies included in the various NWA projects?**

14 A83. Non-Wire Alternatives refer to utilizing technology such as energy storage or  
15 distributed energy resources to defer or replace traditional grid investments. Energy  
16 Waste Reduction (EWR) refers to replacing less efficient equipment with more  
17 efficient equipment, reducing overall electrical demand. Demand Response (DR)  
18 refers to a shift or reduction in electricity usage by a utility customer to help manage  
19 demand on the electrical grid during periods of peak demand. For projects with  
20 EWR and DR technologies, the projects are jointly administered with the  
21 Company’s EWR/DR teams. Behind-the-Meter (BTM) refers to coordinating the  
22 participation of customer equipment to reduce overall demand or provide other

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<sup>20</sup> Case No. U-21534 Order at p. 157.

<sup>21</sup> Case No. U-21534 Order at p. 158.

<sup>22</sup> Case No. U-20836 was captioned “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.”

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1 system benefits. Electric Vehicle (EV) charging refers to coordinating the charging  
2 or discharging of EV equipment to provide electrical system benefits, avoid  
3 electrical system issues, or address loading concerns.

4

5 **Q84. Can you provide an update on the NWA pilot projects?**

6 A84. The Company has made progress on the NWA pilot projects and is planning  
7 remaining work as outlined below:

8 • O'Shea:

9 ○ Progress as of early 2025:

- 10 ▪ Construction completed.
- 11 ▪ Vendor has verified controls and battery operation.
- 12 ▪ ESOC has visibility into battery state of charge.
- 13 ▪ Awaiting final operational commissioning pending final vendor
- 14 adjustments.

15 ○ Remaining planned work:

- 16 ▪ By the end of Q2 2025, SCADA displays and final site
- 17 commissioning will be completed.
- 18 ▪ Throughout 2025, the Company will conduct operational testing
- 19 of battery control modes and test capability for the battery
- 20 system to demonstrate participation in the wholesale market in
- 21 consideration of FERC Order No. 841<sup>23</sup> to vet processes controls
- 22 and communications that can be replicated at future battery sites.

---

<sup>23</sup> FERC Order No. 841 seeks to facilitate the participation of electric storage resources in the RTO and ISO-operated markets.

Line  
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- 1                           ▪ 2025 project completion expense will be requested in a
- 2                           subsequent electric rate case and is not included in Exhibit A-12
- 3                           Schedule B5.4, line 7.
- 4           • Mobile Battery Trailer:
- 5           ○ Progress as of early 2025:
- 6                           ▪ Completed documentation and operational testing of the battery
- 7                           functions in islanded and parallel configurations at medium
- 8                           voltage off-grid at full power.
- 9                           ▪ Identified and implemented modifications to improve
- 10                          deployment time and improve safety when operating the trailers.
- 11           ○ Remaining planned work:
- 12                          ▪ During the 2024 testing, the Company identified opportunities
- 13                          with cabling and controls to improve operator efficiency and
- 14                          reduce deployment time; this work and commissioning will be
- 15                          completed by the end of Q2 2025 and the original allocation was
- 16                          adjusted to provide additional funding in 2025 for this work
- 17                          across the battery trailer systems.
- 18                          ▪ On-grid testing will be conducted to validate the battery system
- 19                          control modes, operational documentation, and communications
- 20                          with the System Control Center. These tests will validate
- 21                          functionality for the battery system, including operator-
- 22                          controlled charging and discharging, peak shaving, volt var
- 23                          control, and solar smoothing functions and onboard monitoring
- 24                          and safety systems.



Line  
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1                   ▪ Procedures for disconnecting, moving, and reconnecting the  
2                   battery systems will be field tested to allow finalization of job  
3                   units and work procedures. The Company will test battery  
4                   systems to work with other mobile resources and DER prior to  
5                   deployment. During the testing, enhancements to functionality  
6                   and control modes will be integrated into the battery trailer  
7                   system to increase the number of use cases they can support, and  
8                   these enhancements will be propagated to the other Battery  
9                   Trailer Systems.

10           • Omega:

11               ○ Progress as of the end of 2024:

12                   ▪ Site construction is complete, and the Company completed  
13                   walkdown and inspection, including validation testing of battery  
14                   systems at primary voltage in an off-grid configuration.

15               ○ Remaining planned work:

16                   ▪ Complete checkout and commissioning of the mobile battery  
17                   systems and primary operation in Q3 2025 in coordination with  
18                   the items identified in the Mobile Battery Trailer project.

19                   ▪ Establish commissioning process and operational procedures for  
20                   peak shaving deployments in the control room and the field for  
21                   coordinating multiple battery systems at the same site in Q3 and  
22                   Q4 2025.

23           • Fisher:

24               ○ Progress as of Q1 2025:

25                   ▪ EWR field marketing concluded in 2024.

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- 1                   ▪ Contracted commercial and industrial (C&I) projects from 2024
- 2                   are scheduled for installation and completion by June 2025.
- 3                   ▪ Currently EWR has reported savings of 224 kW with many
- 4                   projects in progress to be reported upon installation.
- 5                   ▪ Final evaluation and reporting are planned to be completed by
- 6                   year end 2025.
- 7                   ▪ Additional geotargeted marketing for the DR programs, Smart
- 8                   Savers and CoolCurrents, at the Fisher substation concluded in
- 9                   2024.
- 10                  ▪ A cumulative total of 211 customers enrolled in the Smart
- 11                  Savers program at the Fisher substation. Based on a third-party
- 12                  projection, as of March 1, 2025, these customers could each
- 13                  provide an average of 0.62 kW in load shed per DR event,
- 14                  totaling approximately 130.82 kW available in demand savings
- 15                  at customer level.
- 16                  ▪ Additionally, 300 CoolCurrents customers are online and
- 17                  dispatchable at the Fisher substation. According to the same
- 18                  third-party projection, these customers could each provide an
- 19                  average of 0.53 kW in load shed per event, resulting in
- 20                  approximately 159.00 kW available in demand savings at
- 21                  customer level.
- 22                  ▪ The Company called two events system wide for both programs
- 23                  in 2024. The demand reduction impacts of these events are
- 24                  currently being assessed by an independent third-party

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1 evaluator. The evaluation and final report are expected to be  
2 completed by December 2025.

3 ○ Remaining planned work:

4 ■ Scheduled installations are in progress for EWR to complete  
5 work contracted during the 2024 field execution.

6 ■ No additional field work for EWR or Demand Response is  
7 planned for 2025 outside of the evaluation and final report.

8 ■ If instructed, the Demand Response team may call a substation  
9 only demand response event to support any potential needs at  
10 Fisher.

11 ■ Complete reconductoring work started in 2024. 2025 project  
12 completion expense will be requested in a subsequent electric  
13 rate case and is not included in Exhibit A-12 Schedule B5.4, line  
14 9.

15 • Port Austin:

16 ○ Progress as of end of 2024:

17 ■ Substantial site completion of below grade work, overhead  
18 equipment, pad mount equipment and Solar.

19 ○ Remaining planned work:

20 ■ Upon energization of house service in Q2 2025, the  
21 Interconnection gateway will be installed, and once  
22 communications are established, the mobile battery system will  
23 be moved on site.

Line  
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1                   ▪ The control systems, communication infrastructure, new  
2                   processes, standard designs, and other aspects of the pilot will  
3                   be fully verified once the batteries and solar are commissioned.

4                   ▪ The capability for the battery system to demonstrate peak  
5                   shaving participation in the wholesale market will be tested in  
6                   consideration of FERC Order No. 841.

7                   ▪ Microgrid testing will be conducted later in 2025.

8                   • Veridian:

9                   ○ Progress end of 2024:

10                  ▪ The Company completed construction of the URD and  
11                  reconductoring portions of the Veridian project in 2024.

12                 ○ Remaining planned work:

13                  ▪ The microgrid portion is currently in detailed engineering study  
14                  and controls design, procurement of storage, and construction  
15                  will continue into 2025.

16                  ▪ The timing and scale of a Company owned storage installation  
17                  is being aligned with the developer according to the physical  
18                  space constraints on the revised property site plan. The  
19                  capability of controls installed will align with occupancy of the  
20                  development and the developer's installation of customer owned  
21                  solar/storage DER components over the next few years.

22                 • EV Charging Demonstrations:

23                 ○ Progress as of end of 2024:

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- 1                   ▪ The Department of Energy Vehicle Technology Office (VTO)
- 2                   FOA-2197 EVs at RISC program<sup>24</sup> focused on validating the
- 3                   data model and cyber security implementations necessary to
- 4                   provide managed charging in a multi stakeholder environment
- 5                   where charging was dynamically controlled by grid conditions.
- 6                   This included an initial proof of concept demonstration to the
- 7                   DOE in 2023 of the system's ability to control vehicle charging
- 8                   locally and remotely based on real time grid conditions while
- 9                   implementing the required cybersecurity practices to maintain
- 10                  isolation of the utility control network.
- 11                 ▪ Successful demonstration of managed charging at the Bagley
- 12                   parking hub in Corktown (located in the City of Detroit) was
- 13                   done with DOE in Q3 2024 to demonstrate coordinated charging
- 14                   of multiple different vehicles utilizing V2G and V2H under
- 15                   managed charging constraints on both Level 2 and DC fast
- 16                   chargers.
- 17                 ▪ The Electric Marketing organization initiated Smart charge
- 18                   management projects that were tested in multiple phases through
- 19                   2023 and 2024 at the DTE Electric DER lab along with
- 20                   engineering evaluations for OEM pilots on V2H and V2G
- 21                   technologies and technologies to manage home charging in
- 22                   breaker panels with limited ampacity.

---

<sup>24</sup> EVs-at-RISC: A Secure and Resilient Interoperable Smart Charge Management Control System Architecture for Electric Vehicles At-Scale: [elt265 \(energy.gov\)](https://www.energy.gov/sites/default/files/2021-07/elt265_woodbury_2021_o_5-14_500pm_KF_ML.pdf) available at [https://www.energy.gov/sites/default/files/2021-07/elt265\\_woodbury\\_2021\\_o\\_5-14\\_500pm\\_KF\\_ML.pdf](https://www.energy.gov/sites/default/files/2021-07/elt265_woodbury_2021_o_5-14_500pm_KF_ML.pdf).

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1                   ▪ Additional work was performed on EV charging station protocol  
2                   interoperability and compatibility for managed charging and  
3                   demand response and initial investigations into the Electreon  
4                   electric road technology and Vehicle to Grid functionality and  
5                   standards.

6                   ○ Remaining planned work:

7                   ▪ A major portion of the investment during 2025 is the final  
8                   technical demonstration of the DOE program for DE-FOA-  
9                   0002197, EVS-at-RISC (Electric Vehicle Secure - Resilient  
10                  Interoperable Smart Charging). This includes the widescale  
11                  demonstration of the system controlling multiple publicly  
12                  accessible chargers in and around the Michigan Central campus  
13                  in Corktown (located in the City of Detroit). This demonstration  
14                  will help the Company develop cyber-secure monitoring and  
15                  control capabilities with smart charge controls to provide  
16                  reliable and secure interfaces to customer systems. The project  
17                  will further enhance knowledge of the grid impact of these new  
18                  management technologies.

19                  ▪ DC fast charging V2G capability will be tested along with  
20                  testing of vehicle protocol and interoperability as new  
21                  commercially available systems integrate more directly with  
22                  solar and storage and feature more complex controls and the  
23                  ability to operate offline.

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- 1                                   ▪ Engineering will also be done on the inductive road charging
- 2                                   project to better understand the power quality impacts of
- 3                                   wireless charging.
- 4                                   ▪ Engineering support for Electric Vehicle Emerging Technology
- 5                                   Fund (ETF) is primarily around providing feedback to the
- 6                                   individual projects design. Work also includes supporting the
- 7                                   implementation of testing of the solutions and validating the
- 8                                   technical performance of the projects.

9

10   **Q85. Are the EWR costs included in Exhibit A-12, Schedule B5.4 with the other**

11       **NWA pilot costs?**

12   A85. No. Energy Waste Reduction pilot costs are included as part of the Company's

13       EWR Plan in Case No. U-21322, Exhibit A-1.

14

15   **vi. Grid Edge Insights and New Technology**

16   **Q86. What is included in the Grid Edge Insights and New Technology sub-category**

17       **of Grid Automation investments?**

18   A86. This sub-category of Grid Automation investments is a collection of projects

19       designed to consolidate the learnings from the NWA pilot projects into a consistent

20       platform, and to unlock the capabilities of new equipment coming to market to run

21       the grid more safely, reliably, and efficiently, ultimately increasing the amount of

22       DER that can be accommodated on the grid.

23   **Q87. What are the benefits of the Grid Edge Insights and New Technology projects?**

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1 A87. Evaluation and integration of new technology into the grid allows for technological  
2 enhancements to improve grid reliability, resilience, safety, efficiency, and  
3 opportunities for costs savings. Evaluating new technology speeds up the  
4 introduction of new equipment and capabilities, avoiding operational safety and  
5 efficiency concerns when field equipment replacements are unavailable, or vendors  
6 change their products. Investments in Grid Edge Insights will allow connection of  
7 additional NWA and DER resources safely and reliably by coordinating DER  
8 controls with daily grid operations through a standardized gateway platform. A  
9 consistent integration platform reduces project costs and timelines by minimizing  
10 site and controls design and ensures consistent configuration, communications, and  
11 cybersecurity. This simplifies the integration of DER systems to IT systems like  
12 ADMS and the future Distributed Energy Resource Management System  
13 (DERMS). Interconnection of customer DER can be streamlined as substantial  
14 portions of the communication and control are pre-designed inside the gateway.  
15 The modular gateway controls allow expandability for new DER types, control  
16 algorithms, and functionalities, enabling remote management and upgrades to  
17 reduce site visits. Without this standardization, individual NWA projects would  
18 lack a common platform, leading to inefficiency and higher costs and requiring  
19 custom engineering for each DER project.

20

21 **Q88. What progress has DTE Electric made on Grid Edge Insights and New**  
22 **Technology projects?**

23 A88. The Company has expanded the solar and storage testbed for testing  
24 interconnection gateways and battery trailer systems. In 2024, switchgear,  
25 disconnect cabinets, below-grade cable, conduit, and foundations for the 480V test



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1 areas was installed. The large interconnection gateway was tested at the Solar  
2 Testbed and delivered to the O'Shea NWA project and prepared for the Port Austin  
3 NWA project, with a variant incorporated into Battery Trailer systems. Gateway  
4 functionalities for energy storage management and coordination between the utility  
5 control room and market operations were implemented, along with safety and  
6 operating controls for monitoring DER, energy storage systems, and alarms. The  
7 consistent design of the interconnection gateway streamlined NWA project site  
8 plans, reducing engineering and design time. The Hardware-In-the-Loop (HIL)  
9 testing system was installed in the testbed, allowing real-time testing of control and  
10 communications interactions, validating that controls work as anticipated when  
11 deployed into projects. This system is critical for advanced functions like  
12 microgrids, enabling rapid verification of control concepts for NWA projects such  
13 as the microgrid NWA at Port Austin.

14

15 **Q89. What additional investments are planned for 2025 and 2026?**

16 A89. The Company's 2025 and 2026 investments are shown in Exhibit A-12, Schedule  
17 B5.4, page 14, line 31 and include the following:

- 18 • Completing medium voltage and 480V test areas, expanded inverter bays, DC  
19 systems, and training areas.
- 20 • Integrating functionalities into the interconnection gateway for microgrid  
21 operations, networked microgrid capabilities, grid automation coordination,  
22 customer-managed DER, EV and V2G management, and Demand Response.
- 23 • Evaluating and testing medium and small-scale gateway products to benefit  
24 more DER and NWA sites.

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- 1 • New technology evaluations to expand grid automation capabilities to integrate
- 2 with ADMS FLISR, circuit loop schemes, and distribution automation.
- 3 • Gateways and sensor networks to replace system loading visibility lost without
- 4 generation meters for specific customer classes.
- 5 • Enhancing the testbed for customer DER configurations and testing microgrid
- 6 functionalities for NWA projects using HIL simulation and the testbed
- 7 electrical network.
- 8 • Establishing additional standardization and practices for distribution connected
- 9 energy storage and microgrids.

10

11 **Q90. What are the expected benefits of the investments planned for 2025 to 2026?**

12 A90. These investments will substantially increase the Company's ability to integrate

13 both utility and customer owned DER into grid operations and will streamline

14 portions of the design and engineering for large customer interconnections.

15 Additionally, the Company will implement optimization algorithms to allow for

16 more flexible DER operation and increased levels of DER and storage penetration

17 into the distribution system. The HIL system and testbed will be utilized to validate

18 that this new technology and functionality works together without creating

19 unexpected operating behavior and improve the time it takes for new technology to

20 be validated and deployed.

21

22 **b. Operational Technology**

23 **Q91. How does DTE Electric structure its distribution technology investments?**

24 A91. DTE Electric investments in distribution technology—cyber, computing, and

25 communications technology—are primarily divided into Corporate Technology,

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1 which includes traditional IT assets, and Operational Technology (OT), which is  
2 specific to major Company operating units like Distribution Operations. The  
3 Distribution Grid Plan (DGP) outlines a roadmap for Operational Technology  
4 investments in five sub-categories:

- 5 • 1) Grid Management including ADMS;
- 6 • 2) Distribution Planning;
- 7 • 3) Work Management and Scheduling;
- 8 • 4) Asset Management; and
- 9 • 5) Mobile Technology.

10 This structure helps organize and plan the Company's technology investments over  
11 a 5+ year horizon, facilitating alignment and adaptability.

12

13 **Q92. What are the unique considerations DTE Electric must consider when**  
14 **planning for distribution OT investments?**

15 A92. Planning for Operational Technology investments differs from traditional  
16 equipment investments due to the rapid pace of technological change and the  
17 ongoing lifecycle of deployed assets. Unlike long-lasting physical equipment such  
18 as transformers, technology assets require frequent updates and adaptations to  
19 remain effective. This dynamic nature demands a strategy that balances continuous  
20 optimization with prudent investment planning, addressing the evolving technology  
21 landscape and delivering benefits to customers.

22

23 Additionally, OT technology investments face unique challenges such as external  
24 vulnerabilities including cyberattacks, and the corresponding need for  
25 cybersecurity measures. As technology advances, the Company must protect its

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1 assets from both physical and cyber threats, requiring ongoing investment and  
2 adaptation. The fast-paced innovation in technology also necessitates frequent  
3 reviews and updates to investment plans so that the Company keeps pace with  
4 industry advancements and maintains effective, secure, and up-to-date technology  
5 infrastructure.

6

7 **Q93. Where does the Company provide additional details of the Grid Automation**  
8 **capital investments?**

9 A93. The details of the capital investment in this category are provided in the following  
10 exhibits and schedules:

- 11 • Exhibit A-12, Schedule B5.4, pages 14-15; and
- 12 • Exhibit A-23, Schedule M7.

13

14 **i. Grid Management**

15 **Q94. What is Grid Management?**

16 A94. Grid Management is a category of OT investments that enables the Company to  
17 monitor, control, and optimize the operation of the Grid Automation asset  
18 investments. These projects include the full suite of ADMS distribution  
19 management applications, including outage response, fault location, isolation, and  
20 service restoration (FLISR), and advanced control toolsets. Investments in this  
21 category enable distribution operators to model the real-time state of the electrical  
22 system and manage the entire distribution network. Grid Management includes  
23 systems that monitor and control the power system, manage planned and unplanned  
24 outages, and analyze and optimize the quality and reliability of the network. These  
25 investments also include the platforms that will enable the management of

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1 Distributed Energy Resources (DER) such as the DERMS (Distributed Energy  
2 Resource Management System).  
3

4 **Q95. What are the key drivers for the Grid Management investments?**

5 A95. The following key drivers support the Company's Grid Management investments:

- 6 • Cybersecurity: Investing in cybersecurity measures to protect against  
7 potential threats to the grid's infrastructure.  
8 • Electrification: Supporting the growth of EVs and other electrified  
9 technologies, which will drive changes in grid capacity and management.  
10 • Demand Response: Implementing strategies to match electricity  
11 consumption with supply to optimize grid performance.  
12 • Renewable Integration: Adapting the grid to safely and reliably incorporate  
13 renewable energy sources and manage their grid impacts and intermittent  
14 nature.  
15 • Reliability and Resiliency: Enhancing technology infrastructure for extreme  
16 weather adaptation (ADMS), deploying fault detection technologies like  
17 FLISR to minimize outages, and meeting customer expectations for fewer  
18 disruptions.  
19

20 **Q96. Where are the capital investment details of the projects and programs in the**  
21 **Grid Management category provided?**

22 A96. Capital investment details of these projects and programs in this category of the  
23 instant case can be found in the following exhibits:

- 24 • Exhibit A-12, Schedule B5.4, page 14-15; and  
25 • Exhibit A-23, Schedule M7.

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1 **Q97. Did the Audit address the Grid Management investments?**

2 A97. Yes, the Audit supported the Company's Grid Management investments. The Audit  
3 specifically found that the investments in the ADMS, which I discuss further below  
4 in Section IV.b.i.2, in conjunction with the grid automation assets, will improve the  
5 Company's ability to monitor and control the subtransmission and distribution  
6 systems more effectively and accurately by identifying fault locations and more  
7 quickly restoring service to customers by automatic means, remote control means,  
8 and otherwise by better dispatching first responders to locations of faults causing  
9 outages reducing outage restoration time.<sup>25</sup>

10

11 **Q98. Did the Order in Case No. U-21534 address the Grid Management**  
12 **investments?**

13 A98. Yes. The Order in Case No. U-21534 supported the Grid Management investments  
14 and did not disallow any of these expenditures. The Commission directed the  
15 Company to engage with the Staff and file additional support for its EFC program  
16 in future cases.<sup>26</sup> These requirements are addressed in the Error Free  
17 Communications (EFC) discussion in Company Witness Ambrose's testimony.

18

19 **1. SOC Modernization Project – Alternative System Operations Center (ASOC)**

20 **Q99. What is the SOC Modernization Project?**

21 A99. The SOC Modernization project replaced the Company's previous outdated  
22 primary SOC and the smaller, outdated backup SOC by constructing two facilities  
23 designed using current security, resiliency, and operability standards. The former

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<sup>25</sup> Case No. U-21305, [068cs00000AyaNpAAJ](#), Audit Part Two, p. 93.

<sup>26</sup> Case No. U-21534 Order at p. 160.

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1 alternate SOC had several limitations, including outdated physical, end of life  
2 legacy technology that could no longer receive necessary support and updates,  
3 space limitations that constricted future growth for critical reliability functions, and  
4 limited visibility into the performance of supporting telecommunication  
5 infrastructure. The SOC Modernization project was imperative to address these  
6 challenges effectively. The two new facilities are called the Electric System  
7 Operations Center (ESOC) and Alternate System Operations Center (ASOC). The  
8 ESOC and ASOC were completed in 2022 and 2024, respectively.

9

10 **Q100. What is the status of the ASOC?**

11 A100. The ASOC was successfully commissioned with NERC certification and moved  
12 into full operations in November 2024.

13

14 **Q101. How has the SOC Modernization project benefited customers?**

15 A101. Customers benefit from the improved communication paths between personnel  
16 who are co-located in the new facilities. The new communication paths provide  
17 quicker and improved coordination to create and implement restoration strategies  
18 more effectively. In addition, customers benefit from reduced risk of disruption in  
19 operations during outage events, and faster restoration times regardless of whether  
20 the System Operations organization operates from the ESOC or ASOC. The  
21 Company's ability to understand system conditions and dispatch resources to  
22 address issues is greatly enhanced by the technology available in the new facilities  
23 and the co-location of the System Operators, Power Dispatchers, and support  
24 personnel. In addition, ESOC is more resilient and hardened to withstand adverse

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1 natural and man-made disasters, allowing electric grid operations to recover much  
2 more quickly if a major catastrophic event occurred.

3

4 **2. Advanced Distribution Management System (ADMS): Distribution Management**  
5 **System (DMS)/Outage Management System (OMS)**

6 **Q102. What is ADMS: DMS/OMS?**

7 A102. The Advanced Distribution Management System (ADMS) is a modern operating  
8 technology platform essential to the Company's grid management and  
9 modernization efforts, which improves system reliability and operational  
10 efficiency. ADMS software solutions are used to monitor, control, and optimize the  
11 distribution of electricity in real-time.

12

13 ADMS as a platform supports Distribution Management System (DMS) and  
14 Outage Management System (OMS) functionalities to enhance the overall  
15 management of power distribution networks. The series of systems that compose  
16 the ADMS platform represents a significant advance in the Company's situational  
17 awareness of grid condition, coordination of system operators and field personnel,  
18 and control of grid assets. It provides a consistent integrated view of the system to  
19 all organizations, supports faster restoration times, and allows for improved  
20 monitoring and control of the distribution system. While the core elements of  
21 ADMS went live in 2023, DMS and OMS require ongoing investment.

22

23 DMS provides an as-operated network model of the electrical system for operators  
24 to view operating conditions in real time. DMS consists of multiple applications  
25 such as the Network Model (eMap), Distribution Power Flow (DPF), Distribution



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1 State Estimation (DSE), and applications with more advanced functionality such as  
2 Fault Location, Isolation, and Service Restoration (FLISR), Volt/Var Control  
3 (VVC), Conservation Voltage Reduction (CVR), Feeder Reconfiguration (FR), and  
4 electronic Switch Order Management (SOM). The DMS platform was completed  
5 and the project closed out in 2023, but there are ongoing efforts to operationalize  
6 ADMS components. A key ongoing operationalization effort is the FLISR project  
7 described later in my testimony.

8

9 OMS aggregates emergent trouble information reported by customers and AMI  
10 meters and allows system operators and dispatchers to prioritize response and  
11 properly assign crews for repairs, enhancing their ability to manage and minimize  
12 disruptions in service for customers. The OMS went live in the first quarter of 2023.

13

14 **Q103. What investments has the Company completed for ADMS: DMS/OMS?**

15 A103. The Company's 2023 and 2024 investments are shown in Exhibit A-12, Schedule  
16 B5.4, page 14, line 39. DMS and OMS went live in February of 2023. After go-  
17 live the Company moved into the hypercare phase of the project. Hypercare was an  
18 intense and focused phase of support and monitoring that immediately followed go-  
19 live. It involved round-the-clock support for system operations and field personnel  
20 as they became accustomed to operating the new systems. Additionally, EMS  
21 (Energy Management System), which is a software solution that allows for  
22 monitoring and control of the subtransmission and transmission systems that serve  
23 DTE Electric customers, was upgraded at that same time to bring the existing EMS  
24 to a compatible version with OMS and DMS.

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1   **3. ADMS Enhancements**

2   **Q104. What is the ADMS Enhancements investment?**

3   A104. As discussed above, although DMS and OMS were deployed in February 2023, the  
4       Company has continued to build upon this foundation by implementing  
5       enhancements. These enhancements are necessary to keep up with the evolving  
6       needs and challenges of the modern electrical grid, as well as regulatory  
7       requirements and enhancements to strengthen cybersecurity measures to protect  
8       against potential vulnerabilities. Additionally, as discussed in the following Section  
9       IV.b.i.4 regarding Other Grid Modernization, the Company is leveraging the newly  
10      implemented ADMS systems' breakthrough capabilities to improve storm  
11      restoration and customer communication. Initiated in 2023 after the catastrophic  
12      ice storm, these investments were expedited from the overarching ADMS  
13      enhancement plan to promptly deliver value to customers. The Company remains  
14      committed to sustaining and furthering these investments.

15

16   **Q105. Has DTE Electric completed other projects related to ADMS?**

17   A105. Yes. The Company completed multiple projects in 2023 that are related to the  
18       ADMS.

19

20   **Q106. What was the scope of investments planned for ADMS Enhancements in 2024?**

21   A106. In 2024, ADMS Enhancements delivered four sets of planned patches. A patch in  
22       an OT system or program is a set of changes designed to update, fix, or improve it.  
23       The planned patches are necessary to derive the full value of ADMS by increasing  
24       system and user capabilities in the areas of DMS and OMS. For example, ADMS  
25       users may now reassign a customer premise to a new transformer, allowing them

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1 to better model outages and respond precisely to outage events in the moment.  
2 Previously, ADMS users had to relay the correction manually and needed to more  
3 manually engage with the OMS outage event. Patching allowed DTE Electric to  
4 operationalize additional features that enhanced the use of ADMS modules,  
5 including DMS and OMS.

6

7 Also in 2024, the Company invested in the ongoing Switch Order Management  
8 (SOM) work. Safety is a key driver for SOM, which will increase DTE Electric's  
9 capabilities in hazardous energy control. In 2024, DTE Electric continued to build  
10 SOM and its connection to other internal systems, such as Maximo.

11

12 **Q107. What is the scope of investments for 2025 and 2026?**

13 A107. The Company's 2025 and 2026 investments are shown in Exhibit A-12, Schedule  
14 B5.4, page 14, line 12. In 2025, DTE Electric will continue to work with the ADMS  
15 vendor to tactically deploy key patches that are necessary to increase ADMS user  
16 efficiencies and improve the base ADMS functionality. In parallel, the Company  
17 plans to develop and deploy new interfaces between ADMS and other software to  
18 continue providing integrations across DTE Electric platforms. The work on SOM  
19 will also continue with a focus on deploying additional configurations and building  
20 new processes to remove errant data that may impact the Company's ability to use  
21 SOM when performing life critical switching and tagging activities.

22

23 In 2025 and 2026, DTE Electric will perform a major upgrade of the ADMS  
24 platform. While the upgrade will deliver numerous benefits, the primary driver is  
25 upgrading to the modern version of software to facilitate the implementation of the

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1 ADMS DMS/OMS mobile tool. Additional information regarding this tool is  
2 provided in Section IV.b.v.2 of my testimony. The successful implementation of  
3 the ADMS DMS/OMS mobile tool is dependent on having the most recent line of  
4 OMS as they are complementary products. OMS is also complementary to DMS,  
5 especially the as-operated network model tool, eMap. In support of the ADMS  
6 DMS/OMS mobile tool, the ADMS platform will holistically require an upgrade.

7

8 While the primary driver of the ADMS platform upgrade supports the mobile tool,  
9 performing this investment also provides many other benefits to DTE Electric and  
10 its customers. To meet industry and DTE Electric demands, the ADMS vendor has  
11 continued to improve its platform by implementing new features and performing  
12 major re-architectures. For example, in the OMS space, the ADMS vendor has  
13 either already released or will release significant and valuable features like AMI-  
14 based overprediction, AMI-based potential downed conductor detection, and AMI  
15 voltage integration. These tools allow OMS to better interpret information from  
16 AMIs during outage events, yielding a better prediction of which customers are  
17 experiencing an outage. In turn, this will help the Company have a more efficient  
18 response to an event.

19

20 The upgrade to the DMS version will also include critical functionality upgrades.  
21 For example, the ADMS vendor has already released a re-architecture of how  
22 temporary conditions work. Temporary conditions allow ADMS users to maintain  
23 the as-operated network model by adding and deleting temporary conditions that  
24 reflect novel actions performed in the field. In the current DMS version, these  
25 temporary conditions inhibit model maintenance, including adding or removing

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1 permanent devices to the model. The re-architecture of temporary conditions  
2 removes this constraint, which will critically enable DTE Electric to better model  
3 planned work in the field in a way that is vital for the overall implementation of  
4 SOM.

5

6 **4. Other Modernize Grid Management**

7 **Q108. What is Other Modernize Grid Management?**

8 A108. Other Modernize Grid Management represents a diverse set of projects designed to  
9 enhance the Company's operational capabilities, particularly during high-volume  
10 outage events, like a catastrophic storm that can impact hundreds or thousands of  
11 customers. This category of projects includes software improvements and licensing  
12 acquisitions, with each investment contributing uniquely to bolstering the  
13 efficiency and resilience of the distribution system's operational technology.

14

15 **Q109. Are any of the Other Grid Modernization projects addressed by another**  
16 **witness?**

17 A109. Yes. Beginning in 2024, the EFC project, which in 2023 was part of the Other Grid  
18 Modernization investment, shifted to Operational Technology and Error Free  
19 Communication. For the instant case the EFC Core and Customer Facing Systems  
20 project investments is discussed by Company Witness Ambrose.

21

22 **Q110. Which projects were completed during the 2023 historical test year?**

23 A110. The Other Modernize Grid Management projects listed and described below were  
24 completed during 2023.

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- 1 • Open Systems International, Inc. (OSI) license: Open Systems  
2 International, Inc (OSI) is the vendor for ADMS. This investment represents  
3 the purchase of a five-year on-premise license for the mission-critical  
4 Outage Management System (OMS), which is part of ADMS, due to the  
5 2023 expiration of the previous license and warranty. The key drivers and  
6 benefits include cost savings of approximately \$1 million over five years  
7 compared to an alternative purchasing arrangement, enhanced warranty  
8 terms with increased vendor support, and improved cost predictability.  
9
- 10 • Qlik Software License: This investment represents the purchase of a three-  
11 year license to support data analysis and visualization for applications using  
12 OMS data, to replace the previous license that expired in September 2023.  
13 This license is crucial for the functionality of all applications utilizing OMS  
14 data through the enterprise data repository (e.g., the Outage Status  
15 Application that is used to track work/crew assignments, add comments,  
16 upload pictures, update cause codes and estimated restoration times, etc.).
- 17 • Current and Voltage Transformer (CT/VT) Test Console: This investment  
18 represents an end-of-life equipment replacement project for the system used  
19 to perform required testing of low and medium voltage transformers. The  
20 old test console system was well beyond end-of-life with components no  
21 longer commercially available.  
22

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- 1                   • Pre-storm season and Post-storm season ADMS enhancements: The driving  
2                   force behind these enhancements was the need to strengthen storm response  
3                   and communication capabilities considering severe weather events and  
4                   evolving customer expectations. After launching ADMS in early 2023 and  
5                   experiencing significant storms, including a historic catastrophic (CAT)  
6                   storm, the Company identified areas for further enhancement. Key upgrades  
7                   included a remote safety check feature and improved dispatch efficiency by  
8                   grouping wiredown occurrences. These improvements have made the  
9                   system more reliable, user-friendly, and efficient, reducing human error,  
10                  enhancing crew response times, and providing customers with more  
11                  accurate restoration estimates.

12

13   **Q111. What are the Other Modernize Grid Investments as shown in Exhibit A-12,**  
14       **Schedule B5.4, page 15, line 48 for 2024-2026?**

15   A111. In 2024, this category included three projects: (1) Meter Failure Analytics; (2)  
16       Weather Analytics Model; and (3) AMI Network Operations Center (ANOC);  
17       ANOC will constitute all of the investment in 2025 and 2026.

18

19   **Meter Failure Analytics**

20   **Q112. What is the purpose and scope of the Meter Failure Analytics project?**

21   A112. Properly functioning meters are crucial to the Company's timely receipt of  
22       notifications messages regarding voltage levels, outages, and restorations, allowing  
23       the Company to respond swiftly to any disruptions, ultimately minimizing outage  
24       duration. Enhancing predictive meter maintenance capabilities is therefore crucial

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1 for DTE Electric to improve service reliability and achieve 48-hour restoration  
2 goals.

3

4 In 2024 DTE Electric completed development of Meter Failure Analytics advanced  
5 algorithms that combine statistical methods with usage patterns, environmental  
6 conditions, and historical failure rates to determine meter failure probabilities  
7 within the next 90 to 120 days. The Company is currently monitoring its  
8 performance by comparing the predicted failures against actual outcomes to assess  
9 the algorithms' accuracy. These evaluations will help refine the model and ensure  
10 it adapts to any changes in meter performance or external conditions. The  
11 predictions will be integrated with disruption of meter signals to prioritize site  
12 inspections and potential meter replacements.

13

14 **Q113. What are the benefits of the Meter Failure Analytics project?**

15 A113. This project will advance DTE Electric's effort to meet its 48-hour storm response  
16 goal as well as supporting improved accurate customer outage communication, by  
17 reducing the number of meters that have failed in the field but remain installed at  
18 customer sites for more than 60 days by 14,000 in 2026 as compared to 2023.  
19 Additionally, fully functioning meters minimize the need for the Company to issue  
20 estimated bills; ultimately, a reduction in failed meters contributes to a more  
21 transparent and efficient billing process.

22

23 **Weather Analytics Model (WAM)**

24 **Q114. What is the purpose and scope for the Weather Analytics Model (WAM)**  
25 **project?**



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1 A114. Accurate and precise weather prediction is a key part of improving restoration of  
2 outages caused by severe weather. The Weather Analytics Model (WAM) project  
3 is designed to predict weather-related outage events up to 72 hours in advance,  
4 enabling the Emergency Preparedness & Response (EP&R) Team to plan for and  
5 activate the optimal number of field resources. DTE Electric's goal is to restore  
6 customer power within 48 hours and secure wiredowns within 60 minutes. The  
7 project spanned 2023–2024, with key milestones including the development of  
8 automated regression and neural net-based outage predictions using weather data  
9 from the North American Mesoscale Model (NAM), and model refinements for  
10 seasonal conditions.

11

12 **Q115. What are the benefits of the WAM project?**

13 A115. WAM is a necessary tool in the outage forecasting process and provides valuable  
14 information regarding the number of predicted outage events and wiredowns  
15 needed for daily customer outage restoration staffing. WAM enhances decision-  
16 making confidence, particularly in determining whether to bring in external  
17 linemen or other resources. WAM provides granular outage event predictions at  
18 service territory, regional, and hourly levels, facilitating proactive storm response  
19 and improved outage management.

20

21 **AMI Network Operations Center (ANOC)**

22 **Q116. What is the ANOC project?**

23 A116. This project will establish an AMI Network Operations Center (ANOC), whose  
24 primary function will be to monitor, operate, and enhance the AMI network mesh,  
25 spanning from individual meters to the Company's data centers. This project to

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1 build the ANOC capability spans from 2024 through 2027 after which the ANOC  
2 will operate as a department within the overall AMI team.

3

4 The Customer Power Status Visibility (CPSV) project, discussed in Section IV.b.i.6  
5 below, is contingent on the performance and success of the ANOC due to the CPSV  
6 requirement of receiving accurate and timely customer notifications, specifically,  
7 the customer power status (*i.e.*, power on, power off, voltage quality) which directly  
8 feeds DTE Electric's work management and customer notification systems. Due to  
9 the interrelated nature of these two efforts, the ANOC project is fully discussed  
10 within Section IV.b.i.6 in the context of the CPSV project.

11

## 12 **5. Meter Improvements**

### 13 **Q117. What is the purpose and scope of the Meter improvements project?**

14 A117. This is an annual investment to cover routine capital investments used for  
15 replacement of damaged field communications equipment supporting the AMI  
16 Meter Network, equipment and software used in the test lab, and validation of new  
17 firmware releases from equipment manufacturers. The investment covers  
18 equipment purchases and labor to operationalize the equipment in the AMI  
19 network. The project entails replacement of equipment due to aging, environmental  
20 factors, and accidental damage as well as software and firmware used in the AMI  
21 network at levels required by manufacturers. The level of annual investment for the  
22 2024 through 2026 timeframe is an annual estimate based on historical trends with  
23 an increase from prior investment amounts due to an increase in the number of  
24 communications devices deployed, plus increased per unit costs of the equipment  
25 itself.

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1 **Q118. What are the benefits of the Meter Improvement Project?**

2 A118. This investment will support sustainment of the operational state of the AMI  
3 network to the expected performance level of read rate performance greater than  
4 98.5%. Customers will benefit from the project through continuation of billing  
5 based on actual usage reads, outage and restoration messages, and controls  
6 supporting electric reliability such as read rates and interrogation Power Off  
7 Notification (PON) rates.

8

9 **6. Customer Power Status Visibility Program (CPSV)**

10 **Q119. What is Customer Power Status Visibility (CPSV)?**

11 A119. The CPSV program is a collection of projects designed to run in parallel with and  
12 expand the Company's optimization of its Advanced Metering Infrastructure  
13 (AMI) asset for outage detection, restoration confirmation, and consistent  
14 collection of power quality attributes indicating the state of the electric power  
15 provided to customers. CPSV will materially improve the Company's capability to  
16 (1) maintain continuous awareness of the status of each customer's electric power  
17 service, (2) provide the earliest possible detection of customer power state changes,  
18 (3) deliver changes in power state condition to the Company's OMS system to  
19 facilitate outage localization, (4) improve outage remediation durations, (5)  
20 improve the accuracy of customer communications, and (6) improve efficiency and  
21 reduce travel for Company personnel dispatched to outage locations.

22

23 **Q120. What are the key drivers for the CPSV Program?**

24 A120. There are two key drivers of the CPSV program. The first driver is to increase the  
25 success rate of receiving Power Off Notification (PON) messages from the

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1 Company's AMI meters. This will trigger communication to customers regarding  
2 power loss at their location(s) and initiate power restoration actions as soon as  
3 possible. The second driver is to receive Power Restoration Notification (PRN)  
4 messages from the Company's AMI meters within 30 minutes of sustained power  
5 restoration at expected electrical service levels. This will trigger communications  
6 to customers regarding power restoration at their location(s) and initiate job  
7 completion confirmation in the Outage Management and Premise Power Status  
8 systems.

9

10 **Q121. What is the scope of the CPSV Program?**

11 A121. The CPSV program scope includes the following projects through 2026:

- 12 • Remediate battery manufacture defects in Field Area Routers (FARs).  
13 Battery manufacturer defects affect up to 40% of the FARs in the  
14 Company's communications fleet and prevent PON messages from  
15 traveling from meters to Company's data centers in order to be addressed.  
16 This project will remediate the FAR batteries to replace the battery or  
17 controller module and will result in an up to 40% improvement in the PON  
18 reception success rate.
- 19 • Simplify network topography. This project aims to replace approximately  
20 50% of the existing FARs, which have reached the end of their useful life  
21 and rely on connections to other FARs to transmit AMI meter messages.  
22 The new FARs will enhance efficiency by enabling direct transmission of  
23 meter messages to the Company's data centers, reducing reliance on  
24 intermediate connections. By reducing the dependency on multiple

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1 transmissions, this project will result in a 5-10% improvement in the PON  
2 reception success rate.

3

4 • Increase FAR Saturation Across the Service Territory. In a wide area outage  
5 an AMI PON message can reach the Company only by reaching a battery  
6 powered, backhaul enabled FAR or cell tower; some meter signals cannot  
7 reach the Company at all due to distance or low signal strength. This effort  
8 installs additional FARs to allow more AMI meter signals to reach the  
9 Company and will result in a 10% improvement in the PON reception  
10 success rate.

11

12 • Leverage Signals from Bellwether Sites in the OMS. The bellwether  
13 cellular meter project will allow the Company to reliably infer the state of  
14 reclosers on the Distribution System that are not SCADA enabled by  
15 receiving PON and PRN messages at specific (bellwether) locations  
16 downstream from the reclosers. Once the Company can reliably infer the  
17 recloser state (open or closed), it can treat all connected customers  
18 downstream of that recloser as a confirmed outage to trigger customer  
19 contacts and Company restoration actions, or restoration confirmation  
20 activities and associated notifications to customers.

21

22 **Q122. What progress has the Company made with the CPSV Program?**

23 A122. The CPSV program investment included the following highlights in 2024:  
24 remediation of 400 FARs with battery defects; an additional replacement of over  
25 3,000 EOL FARs with backhaul enabled FARs; 300 FARs deployed to cover areas  
26 with weak FAR saturation; and purchase and installation of 20,000 cellular meters

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1 for bellwether sites. The resulting PON success rate increased from 35% to 52% in  
2 2024.

3

4 **Q123. Has the scope of the CPSV program changed since the 2024 ERC (Case No. U-**  
5 **21534)?**

6 A123. Yes. Based on the promising results of the initial 2023 deployment of replacement  
7 FARs, with many more meters successfully reporting information, the Company  
8 decided to accelerate the timeline for the CPSV program to replace the remaining  
9 end of life FARs in 2024 and add additional FARs for replacement in 2025 and  
10 2026 to achieve wider coverage in this area.

11

12 **Q124. What are the benefits of the CPSV project?**

13 A124. This project offers the following benefits:

- 14 • Improved Power Outage Notifications (PONs): By increasing PONs from  
15 28% to 52%, and eventually beyond 70%; customers will receive more  
16 reliable and timely notifications about power-related events.
- 17 • Accurate Restoration Estimates: Enhanced data accuracy allows the  
18 Outage Management System (OMS) to provide more precise restoration  
19 estimates, keeping customers better informed during outages.
- 20 • Reliable Meter Reads: Increased uptime and reliability of the AMI  
21 Network improves meter read accuracy and timeliness, leading to more  
22 precise billing and usage information.
- 23 • Increased dependability: the AMI Network directly contributes to a more  
24 stable and dependable power supply.

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- 1 • Improved Customer Communication: Network improvements so far have
- 2 shown a 30% increase in the success of PONs from the smart meters, and
- 3 an overall network speed improvement by an average of 100ms.

4

5 **Q125. You state above that the ANOC project is discussed further in this section.**

6 **Can you further explain how the ANOC project relates to CPSV?**

7 A125. The CPSV project is contingent on the performance and success of the ANOC to  
8 identify and mitigate communication issues and ensure a highly robust pathway for  
9 meter messages. The Company's outage management, work management and  
10 customer notification systems are fed by routers installed by the CPSV project and  
11 depend on the ability to reliably receive customer power status notifications (*i.e.*,  
12 power on, power off, voltage quality).

13

14 **Q126. Can you elaborate?**

15 A126. The ANOC's capability to analyze, monitor, and respond to outages and storm-  
16 related impacts on the AMI network is critical to the Company's mission to improve  
17 reliability and communication. This capability enables DTE Electric to enhance the  
18 Company's Outage Management System, maintain SCADA connectivity to AMI  
19 meters, monitor Bulk Electrical System (BES) assets, and deliver real-time data for  
20 quick analysis and continuous improvement of ANOC-managed network devices.  
21 By improving the reliability of data consumed by the Company's OMS, the  
22 Company will enhance power status notifications to its customers through the  
23 network's ability to deliver a higher percentage of PONs to the system.  
24 Additionally, by increasing the uptime of FARs and enhancing the AMI mesh  
25 network's uptime and density, the Company will improve communications for

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1 other network traffic, such as the traffic used to operate distribution automation.  
2 This improves the overall reliability of DTE Electric's Field Control Network  
3 strategy. The ANOC project aligns with the Company's goals to improve storm  
4 response, power outage restoration, and real time meter reads, and supports DTE  
5 Electric's Distribution Automation and DER initiatives.

6

7 **Q127. What is the scope of the ANOC project?**

8 A127. The ANOC project scope includes the following activities:

- 9       • In 2024, the Company began work to build the ANOC team and its  
10       capabilities. During the first half of the year, the Company developed the  
11       processes, tools, and resource planning as part of its Customer Power Status  
12       Visibility project. By the end of 2024, this investment had resulted in an  
13       improvement in Power Outage Notifications (PONs) received at the  
14       Company's data centers from the field from 28% of Power Outage  
15       Notifications (PONs) to 52%.
- 16
- 17       • In 2025, the ANOC will begin operating the AMI network assets and  
18       building the next phase, the Performance Center. The Performance Center  
19       will perform the fieldwork required to maintain DTE Electric's network  
20       assets, most of which are located on the Company's utility poles throughout  
21       the service territory. This team will be equipped with the training and tools  
22       to repair, replace, and install FARs and other AMI Network field assets on  
23       poles and other DTE Electric property as needed. The goal of this work is  
24       to improve PONs from 52% to 70%.



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- 1                   • In 2026 and moving forward, the Company will continue daily operations  
2                   and implement improvements learned in 2025 (for example, with regard to  
3                   equipment and system modifications and improving application  
4                   efficiencies) while increasing PONs received to a target greater than 70%.

5

6   **Q128. What are the benefits of the ANOC project?**

7   A128. The ANOC initiative supports the DTE Electric advanced metering infrastructure  
8       (AMI) radio frequency mesh network, which facilitates the acquisition of real-time  
9       data, thereby expediting outage response and enhancing the efficiency of repair  
10      operations. The ANOC Project constitutes a pivotal component in the progression  
11      of DTE Electric's smart grid strategy, enabling continuous real-time surveillance  
12      and proactive administration of the AMI network. Through the enhancement of  
13      Power Out Notifications, the ANOC initiative augments the Outage Management  
14      System (OMS), thereby bolstering grid reliability, optimizing meter usage data, and  
15      improving various functionalities associated with smart meters.

16

17   **Q129. What would be the consequences of not investing in the ANOC project?**

18   A129. Failure to invest in the ANOC capability would result in a significant deficiency in  
19      the precision and timeliness of identifying customer power outages. This deficiency  
20      would, in turn, lead to prolonged durations between the occurrence of an outage  
21      and the subsequent restoration of power. The lack of investment in ANOC's  
22      capabilities would compromise the efficiency of outage notifications, delay the  
23      accurate identification of outage causes, and hinder the prompt assignment of repair  
24      crews. Consequently, the overall outage-restoration process would be adversely  
25      affected, resulting in extended power interruptions for customers and a decline in

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1 the reliability and responsiveness of the Company's outage management system.  
2 Therefore, it is imperative to allocate the necessary resources to enhance and  
3 maintain the ANOC capability to provide timely and accurate restoration of power  
4 services.

5

6 **7. Operational Technology and Error Free Communication (EFC)**

7 **Q130. What is the Operational Technology and EFC investment as shown in Exhibit**  
8 **A-12, Schedule B5.4, page 15, line 47?**

9 A130. This investment supports the operational activities required to provide timely  
10 outage restorations. This category is a combination of operational technology  
11 projects, which I support, and EFC Core and Customer Facing Systems project  
12 investments discussed by Witness Ambrose.

13

14 **Q131. What is the current status of this investment?**

15 A131. In 2024, the Company completed the System Outage Screen (SOS) enhancements,  
16 Damage Assessment and Inspections Image Analytics project, Data Analytics and  
17 Data Engineering Project for Outage Restoration Time Estimates, and Regional  
18 Customer Operations (RCO) Global Positioning System (GPS) Productivity  
19 Enhancement project.

20 The SOS is the primary OT project in this investment category. SOS is a critical  
21 application that supports real-time outage restoration by providing visibility into  
22 outages, field crews, and system schematics. The SOS project encompasses  
23 upgrades to the SOS to enhance system resilience, integrate with the Outage Status  
24 Application (OSA), and migrate key infrastructure to a cloud computing platform  
25 (Azure). These upgrades will support the Company's commitment to reliability and

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1 outage restoration efficiency, particularly in storm conditions, by facilitating  
2 optimal performance and supporting efficient outage management and restoration  
3 efforts.

4

5 In 2024, the following additional initiatives were completed: infrastructure  
6 migration of Plant and Field to the Azure environment; automated testing and  
7 modernization initiatives; dashboard optimization and operational excellence  
8 improvements; and functional enhancements, including Circuit Walkdown, Job  
9 Chronology, and SOS Dashboard job list view.

10

11 In addition to the SOS enhancements, during 2024 the Company also completed  
12 the following projects:

13

- 14 • Damage Assessment Inspections Image Analytics project: this project  
15 collected and analyzed images from the damage assessment (DA) team to  
16 identify assets (*e.g.*, crossarms) and assess their condition. This allowed for  
17 replacement of more costly DA resources with more efficient Single Outage  
18 Damage Assessment (SDA) resources and identification of third-party  
19 wires before dispatching restoration crews, which allows more locations to  
20 be assessed earlier in a storm and prevents line crews from responding to  
21 telecommunications company owned downed lines, allowing them to focus  
22 on downed electrical lines.

23

24 The existing DA process required specialized knowledge, creating a  
25 resource gap and slowing restoration efforts. Additionally, the existing

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1 process lacked the integration with daily planning limited resource  
2 optimization. Without this project, challenges such as resource shortages,  
3 inefficiencies in restoration, and lack of data integration would persist.

4

5 Key benefits included providing the DA team with visual asset data and  
6 improving the model through continuous image training.

7

8 • Data Analytics and Data Engineering Project for Outage Restoration Time  
9 Estimates: This project developed a machine learning model to predict  
10 outage restoration times and improve communication accuracy. This project  
11 delivered more accurate restoration time estimates and reduced timing by  
12 automating the estimation process and replacing manual workflows. In  
13 2024, the Company achieved an overall Storm estimate accuracy of 65%,  
14 meeting the 2024 target. See Witness Ambrose's testimony for additional  
15 explanation.

16 • DO RCO GPS Productivity Enhancement project: This project upgraded the  
17 current global positioning system (GPS) dashboard to address issues such  
18 as data errors, manual refreshing, and the need for real-time reporting. By  
19 leveraging modern technology and cloud-based platforms, the project  
20 reduces manual tasks and provides same-day, real-time metrics. These  
21 metrics include vehicle time to leave, time to the first job, and time returned  
22 to the service center. The refreshed dashboard eliminates gaps in data,  
23 offering a comprehensive view of service center time metrics on the same  
24 day. This project was completed in 2024.

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1 Moving forward, these investments will work together with the separate Outage  
2 WISMO and Map Application Health project addressed by Company Witness  
3 Ambrose to enhance the Company's outage management and storm restoration  
4 efforts and meet DTE Electric's goal of restoring outages within 48 hours. Taken  
5 together, these investments will improve customers' ability to report outages and  
6 receive status updates on restoration from self-service channels.

7

## 8 **8. FLISR Implementation**

### 9 **Q132. What is Fault Location, Isolation, and Service Restoration (FLISR)?**

10 A132. FLISR is a sophisticated software application that integrates with the other ADMS  
11 platform applications, such as Distribution Power Flow (DPF), to enable efficient  
12 fault response and power restoration. FLISR combines advanced automation, real-  
13 time data analysis, and decision support tools to quickly detect, locate, and isolate  
14 faults before restoring power in response to fault events. FLISR functions by  
15 utilizing information from sensors and devices across communications networks.  
16 In more detail, the components that enable the full functionality of FLISR are as  
17 follows:

18 • Distribution Power Flow (DPF): This component is the foundational  
19 application that calculates the power flows and voltages through the eMap  
20 network model. This application is required for the sequentially occurring  
21 components of FLISR to run.

22

23 • Fault Location ("FL" in FLISR): Fault locating estimates the location of a  
24 fault after it occurs on the electric system using fault indicators and fault  
25 current measurements from Distribution Automation. FLISR locates faults

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1 by using Distribution Power Flow outputs to estimate how much fault  
2 current would be created if a fault were to occur at any point on the eMap.  
3 When a fault occurs on the Company's electric system, FLISR can combine  
4 status indications and analog fault currents to estimate where the fault  
5 occurred.

6  
7 • Isolation ("I" in FLISR): Isolation is the process by which the fault is  
8 separated from the rest of the electric system by using available Distribution  
9 Automation switching devices to create an isolation zone, thus minimizing  
10 the number of customers who are impacted by the fault.

11  
12 • Service Restoration ("SR" in FLISR): Service restoration is the process by  
13 which electric service is restored to customers outside of the isolation zone  
14 by operating Distribution Automation devices. FLISR utilizes DPF to  
15 ensure that proposed service restoration switching solutions will not result  
16 in unacceptable loading or voltage violations.

17

18 **Q133. What are the key drivers of FLISR?**

19 A133. This investment provides fundamental support to DTE Electric's initiative to  
20 improve overall outage restoration and storm restoration commitments, and the  
21 Company agrees with the Commission's statement in Case No. U-21297 that,  
22 "outage restoration is a critical area" (12/1/2023 Order in Case No. U-21297, pg.  
23 114). The continued investment in FLISR will help the Company improve storm  
24 restoration via reduced outage duration and continue realizing the full benefits of

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1 ADMS. The FLISR investments are shown in Exhibit A-12, Schedule B5.4, page  
2 15, line 46.

3  
4 The ability to isolate and restore in near real-time is dependent on both FLISR and  
5 field equipment that is described in the Distribution Automation section of my  
6 testimony. As DTE Electric system capacity increases and as there is an increase of  
7 SCADA penetration, the Company will be able to use FLISR to aid in reconfiguring  
8 the electrical system when a fault occurs and reduce outage size and outage duration  
9 for customers overall.

10  
11 Additionally, the components of FLISR allow the Company to respond to  
12 undesirable situations on the electric system in a modernized manner. The isolation  
13 and service restoration functionality will now allow for the near-real-time use of  
14 non-protective devices to create an isolation zone and perform restoration  
15 switching. The inclusion of non-protective devices contrasts with how the electric  
16 system is currently configured to operate near real-time. FLISR will generate more  
17 opportunities to reduce customer outage size and duration than are currently  
18 available.

19

20 **Q134. What are the benefits of FLISR?**

21 A134. FLISR offers an array of benefits to DTE Electric and its customers. Improved fault  
22 locating logic will reduce outage duration and decrease strain on devices involved  
23 in local logic fault hunting schemes. On-demand isolation and service restoration  
24 plans will provide quick and precise ways to reduce the size of outage events.

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1 Improved fault locating logic benefits customers experiencing a sustained outage  
2 by allowing DTE Electric to send crews directly to an estimated fault location  
3 instead of first needing to perform patrols. This becomes especially important in  
4 certain areas within the electric system, such as the subtransmission network, where  
5 crew patrols may take longer due to long travel distances and the challenge  
6 presented by many overhead line miles not being easily truck accessible. This  
7 directly impacts the overall customer outage duration by reducing a key part of the  
8 restoration timeline; crews must patrol to find the cause of the fault before they can  
9 either repair or perform restore before repair (RBR) work. Getting to the fault  
10 location more quickly will reduce the overall duration of the outage, directly and  
11 positively impacting DTE Electric's SAIDI.

12 In addition to more quickly locating faults, FLISR isolation and service restoration  
13 reduces the size of sustained outages by isolating the impact of the fault and  
14 restoring some of the customers in the initial outage area. When a fault occurs, a  
15 protective device will operate automatically to clear the fault from the electric  
16 system, typically resulting in a sustained outage for all customers downstream of  
17 the protective device. Isolation and service restoration will reduce the number of  
18 customers impacted from the initial amount downstream of the protective device to  
19 a smaller zone by utilizing additional Distribution Automation switching points  
20 both upstream and downstream of the fault to create an isolation zone about which  
21 customers may be restored.



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1 These combined benefits result in all-weather SAIDI improvements for DTE  
2 Electric's system. The two main benefit drivers are fault location identification and  
3 restoration switching analysis.

4

5 **Q135. Are there other benefits of the FLISR investment?**

6 A135. Yes. In addition to reducing outage duration and therefore system SAIDI, using the  
7 centralized logic FLISR will reduce the number of operations incurred by devices  
8 on the subtransmission system compared to the current local fault hunting logic.  
9 This can prolong these devices' usable lives.

10

11 DTE Electric's loop schemes, designed to provide a level of power redundancy in  
12 certain areas of the grid, face challenges on many circuits caused by limited  
13 capacity. In addition, in certain situations the loop scheme is unidirectional by  
14 design, meaning that one circuit can host load from a second, adjacent circuit but  
15 the second, adjacent circuit cannot host load from the first circuit. Additionally,  
16 there are situations where a loop scheme is effectively disabled during periods of  
17 high loading because the loop scheme operation may result in unacceptable system  
18 violations. In contrast to the loop scheme design, the centralized logic of FLISR  
19 does not require one-way configurations or preemptive disabling. Rather, it uses  
20 the real-time state of the electric system and Distribution Automation devices, as  
21 modeled in the eMap, SCADA indications, and forecasted loading as inputs to DPF  
22 to make decisions in the moment of whether additional service restoration is  
23 permissible. The dynamic decision-making process can result in successful service  
24 restorations in situations where the local logic may have been defeated.

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1           Additionally, FLISR can be enabled one feeder at a time, as outlined in the  
2           implementation plan described later in my testimony. DTE Electric and customers  
3           gain the benefits for feeders where FLISR is enabled incrementally as it is being  
4           implemented over time.

5

6       **Q136. What is the implementation plan for FLISR?**

7       A136. FLISR will be implemented on a step-by-step basis to incrementally add capability.  
8           With this plan, the Company's electric system will see incremental benefits every  
9           year of the project, as opposed to an investment where all benefits happen at the  
10          end of the project. The implementation plan starts with enabling the fault locating  
11          functionality within FLISR, followed by isolation, and finishes with service  
12          restoration.

13

14          FLISR is currently planned for a five-year phased deployment to coincide with the  
15          planned installation of the SCADA-enabled field devices. The implementation of  
16          FLISR, the installation of additional field devices, FLISR enablement of existing  
17          field devices, and increases to system load capacity all offer benefits to DTE  
18          Electric and its customers without dependency on each other. Taken together the  
19          combination of these benefits is expected to provide greater customer benefit than  
20          the sum of each part, which is what has driven DTE Electric to align these efforts.

21

22       **9. Distributed Energy Resources Management System (DERMS)**

23       **Q137. What is the DERMS?**

24       A137. The grid of the future will need to be updated in order to incorporate new  
25       technologies, including DER such as solar and Battery Energy Storage Systems

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1 (BESS). Additionally, requirements for functionality come from MISO to  
2 implement FERC 2222. To enable and support these resources and manage the  
3 complexities they bring with intermittent and two-way power flow, utilities must  
4 carefully plan for DER integration before the actual DER technologies are built.  
5 DERMS is a control system specifically designed to manage DER at the residential,  
6 commercial, industrial, and distribution grid levels. A DERMS acts as a  
7 switchboard for DER-related protocols and information to simplify the  
8 management of these disparate systems and feed information into other utility  
9 backend systems for planning, operations, and customer engagement. In addition  
10 to solar and storage, these DERs can include demand response, electric vehicles, or  
11 other distributed technologies.

12

13 For example, the loading on a distribution circuit needs to be managed within  
14 operating limits during peak times and the DERMs would be used to coordinate  
15 messages from MISO, system maintenance and real time conditions on the circuit  
16 to determine the best resources to use to meet the required outcome, such as  
17 inhibiting operation for worker safety or when to charge energy storage as to not  
18 contribute to peak loading. DERMs will also provide the functionality to track  
19 performance of the DER for program compliance and reconciliation of metering.  
20 This granularity of tracking multiple DER at the same location on the circuit and  
21 coordinating the operation in real time does not currently exist and can only be  
22 accomplished with a DERMs system.

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1 **Q138. What grid functionality is provided by DERMS?**

2 A138. The Company is implementing a Utility DERMS, which provides significantly  
3 more functionality than DERMS that are designed solely for aggregation of DER.

4 A Utility DERMS is composed of multiple key functionalities:

- 5 • Tracks the location, status, configuration, and capabilities of all DER on the  
6 electrical system.
- 7 • Tracks the energy management and economic program assignments,  
8 criteria, and constraints for each DER and identifies and prevents conflicts.
- 9 • Provides interfaces to all of the DER related protocols, controls (both  
10 utility-controlled and vendor-controlled), and to utility information systems  
11 such as Customer Relationship Management (CRM), Billing, Market  
12 Systems, and the ADMS.
- 13 • Provides the capability to capture data, availability, and performance from  
14 the DER, either directly or from third parties and to send dispatch  
15 commands to those devices.
- 16 • Forecasts the real time and short-term availability, energy balances, and  
17 capabilities of registered DER, including Demand Side Management and  
18 Demand Response, and coordinates solar, storage, and flexible loads to  
19 regulate peak demand, execute energy efficiency, and align with utility and  
20 market programs.
- 21 • Optimizes dispatch commands both for energy savings and economics,  
22 while maintaining and respecting program constraints, customer decisions,  
23 and grid constraints and maintains the operability of the electrical system.
- 24 • Aggregates DER into groups for easier coordination, control, and dispatch,  
25 and automates the dispatch and optimization functions with algorithms to

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1 support Transmission and Distribution System coordination while  
2 balancing market and real time operational constraints.

3 • Tracks and reconciles DER metering and program compliance and  
4 alignment with financial aspects of market interfaces for compliance with  
5 FERC Order No. 2222.<sup>27</sup>

6 Due to its broad scope, a DERMS must have interfaces to nearly all utility systems,  
7 most importantly the ADMS, market, and customer information systems.

8

9 **Q139. What is the benefit of a DERMS?**

10 A139. The DERMS provides a central location to consolidate interfaces to different DER  
11 types and vendor systems and interacts consistent with the ADMS. Without this  
12 consolidation each different type of DER or vendor system would need a custom  
13 integration to the ADMS and changes to vendor interfaces would impact ADMS  
14 operations, making each integration more costly and time consuming. The DERMS  
15 also provides for optimization of dispatch of DER, allowing the system operator,  
16 or market signal, to set a dispatch goal in the ADMS for a specific area of the  
17 system. The DERMS evaluates the available and registered resources to accomplish  
18 the goal, balancing DER constraints and customer impacts with the timing and  
19 duration of the dispatch. Taken together these capabilities enable growing levels of  
20 DERs on the grid while maintaining reliability.

21

22 **Q140. What is DTE Electric's strategy for deploying a capable DERMS system in a**  
23 **way that balances the necessary capabilities with needed investment?**

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<sup>27</sup> FERC Order No. 2222 seeks to better enable DER to participate in the electricity markets run by regional grid operators. The Midcontinent System Operator, Inc. (MISO) compliance filings and FERC orders related to Order No. 2222 implementation may be found at FERC Docket No. ER22-1640-000, et. seq.

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1 A140. The Company's strategy is to focus on the areas where DERMS is needed for  
2 compliance and areas where it can increase the efficiency of existing processes and  
3 systems and build interfaces or consolidate systems that currently do not work  
4 together. Under this approach, components are implemented as they are needed and  
5 at the scale that they are needed. Some of the first components that are needed are  
6 consolidation of management systems that coordinate DER and DR data as well as  
7 program participation and interface to the ADMS. This will allow current DR and  
8 DER programs to be tracked more efficiently, benefitting customers that are  
9 currently in DR, load management and DER programs, and enabling the dispatch  
10 of larger existing SCADA controlled assets in coordination with the ADMS and  
11 Market Systems to support currently implemented programs (such as implementing  
12 the requirements of FERC Order No. 841). Future phases of DERMs will focus on  
13 developing and implementing forecasting and optimization capability and  
14 automation of constraint management and Distribution System Operator  
15 (DSO)/Transmission System Operator (TSO) coordination.

16

17 **Q141. What is the planned scope of DERMS implementation in 2025 and 2026?**

18 A141. The Company's 2025 and 2026 investments are shown in Exhibit A-12, Schedule  
19 B5.4, page 15, line 45. DTE Electric has identified a key list of requirements for  
20 framework, functionality, demand response, and integration into utility systems  
21 based on documentation from MISO compliance filings and ongoing workshops.  
22 The initial investment will be in the DERMS software licensing, program, and  
23 configuration database to centralize DER program management, related  
24 constraints, and the tools to assign DER to system model nodes. This will be done  
25 in parallel with ADMS enhancements to be able to control dispatch of identified

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1 resources and enforce constraints at circuit level granularity. These first interfaces  
2 will utilize existing programs including Commercial Interruptible customers,  
3 Demand Response, Interruptible heating and air conditioning, Load Management  
4 System functionalities, and other DER programs. Investments in 2026 would  
5 include implementation of DERMS systems components and creation of interfaces.

6

7 **Q142. Will this approach be able to scale to support the state's clean energy**  
8 **transformation?**

9 A142. Yes, this approach allows for capacity to expand while adoption rates of DER are  
10 growing. By addressing fundamental systems and data and investing in and  
11 implementing components as they are needed and at the scale they are needed, the  
12 DERMS implementation will benefit existing customers participating in DR and  
13 DER programs today and expand as implementation of FERC Order No. 2222  
14 progresses.

15

16 **Q143. What alternatives were considered and what is the risk of not proceeding with**  
17 **investments in DERMS?**

18 A143. The only alternative is to not develop a DERMS or delay investment, which would  
19 result in missing compliance dates to meet MISO's implementation of FERC Order  
20 No. 2222. This would prevent some customers from participating in market  
21 programs and leave the Company unable to coordinate grid operations with  
22 program participants. Additional risks include the need to conduct extensive  
23 manual processing and coordination of DER resources, which would increase labor  
24 costs and significantly slow down registration and operations.

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1    **10. Substation Cybersecurity Program**

2    **Q144. What is the Substation Cybersecurity Program?**

3    A144. As technology and automation investment grows, the number of devices deployed  
4       on the grid will also grow, driving a need for increased cybersecurity to protect the  
5       devices and grid controls. The Substation Cybersecurity program develops and  
6       deploys cybersecurity tools, supporting the increasing number of distribution  
7       automation devices across DTE Electric substations and circuits. This program  
8       implements tools that align with the governance provided by the Enhance and  
9       Expand Cyber Security Program discussed in Section IV.b.v.3 of this testimony.

10

11   **Q145. What are the scope and benefits of the Substation Cybersecurity Program?**

12   A145. This program evaluates specific cyber solutions for distribution equipment. The  
13       Company's investments in the Substation Cybersecurity Program are shown in  
14       Exhibit A-12, Schedule B5.4, page 14, line 16. During 2023, the program made  
15       improvements to the physical security at Stone Pool substation, including procuring  
16       and testing software for situational awareness, threat and vulnerability  
17       management, and asset and configuration management. In 2024, the Company  
18       completed testing, including for pole top communication devices, and further  
19       integrated physical and cyber alerts to close out the Stone Pool Substation portion  
20       of the project. Investments in 2025 will include completing the pole top cyber  
21       equipment assessment, which will inform future process and program  
22       developments to ensure increased monitoring and control of the distribution system  
23       is paired with the necessary increases in cybersecurity.



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1     **11. Automation Configuration Database**

2     **Q146. What is the Automation Configuration Database Project?**

3     A146. The Automation Configuration Database project represents an investment in tools  
4         for improved tracking of intelligent electronic devices, specifically distribution  
5         relay and network communications equipment. Traditional relay databases may  
6         only capture information such as device type and settings. As distribution  
7         automation equipment become more sophisticated, it becomes important to track  
8         additional information such as device configurations, software version, and  
9         firmware status to provide a version history of changes to the system configuration  
10        as they are being deployed and to detect conflicts in settings and logic. The  
11        Automation Configuration Database can be thought of as storing the ‘code’ of how  
12        the grid and each device in it automatically operates. A rigorous system is needed  
13        to make sure all the components work together to prevent mis-operation and  
14        provide a way to handle the increasing number of configurations that will come  
15        with the DER and Distribution Automation as they are added to the grid. Device  
16        Configuration and Settings tracking is critical for the System Operator to see what  
17        software is installed on devices to make the right decisions for proper and safe  
18        operations of the electric system during normal, planned, and emergency situations.  
19        Software and firmware version tracking is needed to make sure the latest patches  
20        are applied to keep the electric system cybersecure. It is also important that this  
21        data is stored in a readily accessible way to allow for connection with other data  
22        systems, effective patch management, and cybersecurity monitoring.

23

24     **Q147. What is the scope of investment, as shown in Exhibit A-12, Schedule B5.4, page**  
25        **15, line 44.in the Automation and Configuration Database project for 2026?**

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1 A147. This project will replace the existing in-house database with an industry standard  
2 tool, improving data accessibility and the Company's ability to coordinate asset,  
3 work management, and protection data between databases. The 2026 scope will  
4 include the purchase and implementation of the database, purchasing test sets, and  
5 integration with the database.

6

7 **Q148. What are the benefits of the Automation Configuration Database project?**

8 A148. The Automation Configuration Database project will improve work efficiency and  
9 support increases in automation, which will result in faster design of projects for  
10 customers, reductions in commissioning and maintenance duration where  
11 equipment is out of service, and minimization of the risk of devices being  
12 misconfigured or having out of date settings that could adversely impact customer  
13 reliability.

14

15 **Q149. What alternatives were considered and what happens if the Automation**  
16 **Configuration Database project is not implemented?**

17 A149. The current system was developed internally over a decade ago and no longer  
18 supported or eligible for upgrades. Without a new system the increasingly complex  
19 configurations of automation devices will not be accurately stored and aligned to  
20 optimized processes, which can lead to inefficiencies in job execution and a risk of  
21 inaccurate or missing records that could jeopardize system operation reliability and  
22 safety. The Company considered multiple vendor solutions when considering  
23 alternatives and conducted benchmarking with other similar utilities to select a tool  
24 that would provide a standard method to accurately collect information from relay

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1 test sets and maintain automation settings and records for efficient storage and  
2 updates.

3

4 **ii. Distribution Planning**

5 **Q150. What is included in the Distribution Planning investment sub-category of**  
6 **Operational Technology?**

7 A150. The dynamic nature of the grid requires that engineers regularly analyze grid  
8 capabilities, including capacity, reliability, and adequate voltage support, to support  
9 integration of new load, DER, and other emerging customer needs. Distribution  
10 Planning is a category of investments in the tools, processes, software applications  
11 and data models supporting the near- and long-term planning of the DTE Electric  
12 distribution system. It includes the applications to correlate and consolidate  
13 changes to the electrical system model so that the different planning tools and the  
14 ADMS can utilize the same data set to perform the necessary analysis for power  
15 flow, power quality, contingency analysis, and project scenarios. These tools assess  
16 the impact of bulk power system modifications, customer requested interconnection  
17 and loading changes, and utility-initiated upgrades to the electrical system. This  
18 category also includes the tools to assess the civil, mechanical, and structural  
19 aspects of project engineering and design. In concert, these tools and systems allow  
20 the Company to optimize projects and consider alternatives in a quantitative and  
21 physics-based manner.

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1 **Q151. Where are the capital investment details of the projects and programs in this**  
2 **sub-category provided?**

3 A151. Capital investment details of these projects and programs in this sub-category are  
4 included in the following Exhibits:

- 5 • Exhibit A-12, Schedule B5.4, page 14-15; and
- 6 • Exhibit A-23, Schedule M7.

7

8 **Q152. What are the benefits of the Distribution Planning investments?**

9 A152. These investments enhance existing engineering, design, forecasting and modeling  
10 capabilities to incorporate new tools and interfaces to allow more frequent and  
11 accurate modeling of the distribution system and analysis of planned changes. A  
12 number of different tools are used by engineering and design personnel during the  
13 development of a project and during annual system studies. These supporting tools  
14 and calculations are needed to implement distribution projects to design standards  
15 and also include streamlining the customer interconnections process. These  
16 investments add new software, keep existing tools up to date, add enhancements  
17 and capabilities, and improve the efficiency of the engineering and design process  
18 resulting in improved project designs.

19

20 **Q153. Did the Audit address the Company's Distribution Planning investments?**

21 A153. Yes, the Audit concluded that these investments respond to important planning  
22 needs and will improve data and analytical tools for designing the future electrical  
23 grid. These improvements will be in both classic planning activities and those that  
24 come with a grid designed to meet expanded customer needs and access. The Audit  
25 concluded that these investments "in combination with ADMS applications will

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1 provide additional detail about the system and improve modeling of it. They will  
2 support the ability to identify emergent circumstances and configurations that  
3 threaten failures and improve electrification and DER scenario development and  
4 available DER Hosting Maps. They thus support both classic planning activities  
5 and those that come with a grid designed to meet expanded needs for modelling  
6 Distributed Energy Resources.”<sup>28</sup>

7  
8 **1. Network Management System (NMS)**

9 **Q154. What is the Network Management System (NMS) program?**

10 A154. As part of the ADMS project, the Company implemented a Network Management  
11 System (NMS) in 2020. NMS incorporates network data from the Geographic  
12 Information System (GIS) and combines the network data with other systems to  
13 directly serve the new ADMS functionality. The current NMS is a single  
14 consolidated common network model that provides a consistent view of the  
15 electrical system in real time, which is used by all functions of the ADMS. This  
16 data model is also used by the distribution planning tools to provide the base model  
17 information for all planning studies. High-quality data is the backbone of the  
18 ADMS system and distribution planning tools. Establishing the NMS Network  
19 Model and investing in data quality improvements are foundational to enabling the  
20 potential value in the remaining ADMS components, such as FLISR. This is vital  
21 to achieve OMS accuracy and accurate customer communications, and to avoid  
22 unnecessary truck dispatch (or rolls) to locations on the system during outages.  
23 NMS supports DTE Electric’s long-term goals for reduction in SAIDI. In addition,  
24 NMS data availability and quality provide critical mapping model data that is used

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<sup>28</sup> Case No. U-21305; [068cs00000AyaNpAAJ](#), Audit Report, Part Two at p. 93.

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1 by planning tools to analyze loading, reliability and DER interconnections and  
2 operational tools that are used to support the Company's 48-hour storm restoration  
3 target.

4

5 **Q155. How did DTE Electric structure and implement the NMS program?**

6 A155. The NMS program was broken up into multiple phases to align with the short-term  
7 and long-term data requirements for ADMS and other projects. The initial phase of  
8 NMS included implementing operational dashboards for monitoring data quality,  
9 employing machine learning models to correct data issues, and consolidating  
10 multiple sources into a single location GIS for use in external systems. In 2020,  
11 following the successful completion of the initial phase and setting the foundation  
12 for maintaining high-quality systems for data, the Company implemented  
13 additional initiatives to improve and add more information into the Company's  
14 network model, enabling future technology investments and existing technology  
15 enhancements to maintain a high level of accuracy.

16

17 **Q156. What has the MPSC concluded regarding past investments in NMS?**

18 A156. In Case No. U-21297 the MPSC stated that "The Commission agrees with DTE  
19 Electric that '[g]rid needs are dynamic, and the tools to support reliability and grid  
20 modernization also need to adapt and develop to support these emerging grid  
21 needs.'"<sup>29</sup>

---

<sup>29</sup> Case No. U-21297 Order at p. 116 (Dec. 1, 2023).

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No.

1 **Q157. What progress has the Company made with the NMS project since the initial**  
2 **phase was implemented in 2020?**

3 A157. In 2023, DTE Electric completed the following work:

- 4 • Common Platform: 77 operational maps were converted.
- 5 • Network Model Enhancements: 15 new data fields were added to the
- 6 network model.
- 7 • Asset Data Integration: 4 asset types were synchronized between GIS and
- 8 Maximo.

9 Data quality for switches, fuses, and regulators improved by 30%. In addition, the  
10 Company completed the AC network meter connectivity pilot and started to support  
11 the Distribution Power Flow (DPF) application in enhancing the network data  
12 models.

13

14 In 2024, the Company completed the following work:

- 15 • Common Platform: 97 operational maps were converted.
- 16 • Network Model Enhancements: 7 new data fields were added to the network
- 17 model.
- 18 • Asset Data Integration: 4 asset types were synchronized between GIS and
- 19 Maximo.

20 Data quality for Primary overhead line, Secondary overhead line, Primary  
21 underground line, and Secondary underground line improved by 10%. The  
22 Company also completed the AC network meter connectivity project and developed  
23 new automated algorithms to improve phasing and meter to transformer  
24 connectivity using machine learning models.

25

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1 **Q158. What additional investments are planned for the NMS Phase 2 Project in 2025-**  
2 **2026?**

3 A158. The Company's 2025 and 2026 investments are shown in Exhibit A-12, Schedule  
4 B5.4, page 14, line 18.

5 The 2025 Scope includes:

- 6 • Develop automated machine learning models to provide continuous and  
7 seamless data updates. These models autonomously monitor, process, and  
8 update data without manual intervention. This approach not only enhances  
9 efficiency but also ensures that the data remains current and reliable for real-  
10 time decision-making and analysis.
- 11 • Execute a strategic alignment of four new critical asset categories across the  
12 Geographic Information System (GIS) and Maximo platforms.
- 13 • Continue the development of new innovative algorithms to refine phasing  
14 accuracy and bolster meter-to-transformer assignments. The algorithms will  
15 run automatically to update data as appropriate.
- 16 • Implement a new automated data correction tool for transformers with an  
17 anomalously high customer count relative to their rated kVA capacity.
- 18 • Develop an automated tool for substation data through an optimized ESRI-  
19 Maximo workflow integration.
- 20 • Create a specialized new automated tool for the precise extraction of  
21 phasing information from operational maps of distribution circuits and  
22 update data as appropriate.



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1 The 2026 scope includes:

- 2 • Develop new methodologies utilizing geospatial intelligence to automate
- 3 and improve GIS capabilities.
- 4 • Develop new automated machine learning models to improve network
- 5 model data using output from the LIDAR technology project.
- 6 • Utilize data from different programs across distribution operations (*i.e.*,
- 7 Asset Management Programs/Inspections) and build new automated
- 8 processes to update data without manual intervention.
- 9 • Execute a strategic alignment of four new critical asset categories across the
- 10 Geographic Information System (GIS) and Maximo platforms.

11

12 **Q159. What are the benefits of the NMS Phase 2 project?**

13 A159. NMS Investments to date have improved the Company's operational ability to  
14 generate maps from GIS, improved load analysis ability, and enabled more accurate  
15 preventative maintenance planning. NMS Phase 2 investments will continue to  
16 improve the data quality as outlined below:

- 17 • Improving downstream processes—including distribution planning, grid
- 18 operations, and customer interconnections—resulting in more accurate load
- 19 analysis from using data combined into one Network Model;
- 20 • Improving data accuracy and availability of specified asset types, such as
- 21 attribute data quality, including fields such as kVA, operating voltages, and
- 22 phasing;
- 23 • Improving preventative maintenance schedules and system reliability with
- 24 accurate asset data by synchronizing the data in the GIS platform with the
- 25 data in the work management platform (Maximo);

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- 1 • Improving outage restoration times due to reduced truck rolls based on
- 2 correct meter to transformer connectivity;
- 3 • Increasing customer and crew safety by dispatching crews to the correct
- 4 outage location; and
- 5 • Providing accurate customer communication by utilizing accurate data that
- 6 improves estimated outage restoration times.

7

8 **Q160. Does this project have associated Operations and Maintenance expenses?**

9 A160. Yes. As shown in Exhibit A-13, Schedule C5.6, page 2, the Company is requesting  
10 \$0.5 million annually for NMS/ESRI Data Quality Controls.

11

12 **Q161. What is NMS/ESRI Data Quality Controls?**

13 A161. The NMS/ESRI Data Quality Controls is the foundational capability to improve  
14 data quality and data gathering processes that feed into the various reliability  
15 analytics. This work is focused on ensuring updates in the NMS and ESRI systems  
16 are reflected and synced in both systems.

17 **Q162. How will the data quality controls be enabled?**

18 A162. The Company is proposing to hire resources and build additional software tools for  
19 data governance and quality control.

20

21 **2. Load Forecasting & Analytics**

22 **Q163. What is the Load Forecasting and Analytics program?**

23 A163. Load Forecasting and Analytics is a program of investments in planning tool  
24 capabilities that focuses on the essential industry standard distribution planning tool

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1 CYME that models distribution circuits and calculates load flow, and the load  
2 analysis tool Power Runner that combines SCADA, AMI and forecasted load data  
3 to generate load allocation scenarios to CYME. This category of investments  
4 includes required software licensing, associated server hardware, interfaces, and  
5 functionality enhancements for this software and supporting planning tools.

6

7 **Q164. What investments did DTE Electric make in 2023 and 2024, and what are the**  
8 **benefits to customers of those investments?**

9 A164. Investments in 2023 and 2024 included the upgrade of the CYME distribution  
10 planning tools and associated required licensing and server hardware updates to the  
11 latest supported version, which will enable improved modeling for hosting capacity  
12 and non-wire alternatives. These investments included CYME modules for  
13 reliability analysis of planned work, integration for DER processing, system tracing  
14 tools for identifying relationships to transmission model nodes, and tools to  
15 facilitate voltage conversion work and automation of common planning functions.  
16 The Company also initially deployed Power Runner licensing in 2023 and updated  
17 interfaces to the NMS network model to accurately represent system connectivity  
18 as it changes. Further investments included servers and software that combines  
19 SCADA, AMI, and forecasted load data from every meter on the system, to produce  
20 hourly load allocation curves. For subtransmission tools, the Company purchased  
21 the Transient Security Assessment Tool (TSAT) software and the required licenses,  
22 as it is now a requirement for the Company to process specific inverter models  
23 during MISO Dynamic model studies that it was not required to do so before. These  
24 enhancements streamline and increase the accuracy of studies that utilize custom  
25 dynamic models for DER installations that other tools cannot process.

Line  
No.

1   **Q165. What investments are planned in 2025 and 2026, and what are the benefits to**  
2       **customers of those investments?**

3   A165. The Company's 2025 and 2026 Load Forecasting and Analytics investments are  
4       shown in Exhibit A-12, Schedule B5.4, page 14, line 21. In 2025 the Company's  
5       investments include enhancing CYME to load data from Power Runner to allow for  
6       multi time period scenario analysis and implementing CYME Advanced Project  
7       Manager, which allows sequencing of system model changes to project plans and  
8       linkage to Maximo workorders. Enhancements will also be made to allow for  
9       substation models to be loaded into CYME to improve the analysis of circuit load  
10      transfers, conversion, and consolidation. The combination of the Dynamic Data  
11      Pull (DDP) module for load allocation and Advanced Project Manager (APM)  
12      module allows projects to be studied in multiple phases and validate that schedule  
13      changes to projects do not violate loading and voltage constraints. This will also  
14      improve interconnection studies as the in-service date of projects can now be  
15      considered for coincident projects to determine interactions that would not be  
16      identified by single point in time studies.

17

18      Also, in 2025, enhancements to CYME will begin the implementation of the  
19      Advanced Distribution Planning System, which is a collection of CYME  
20      enhancements that are being developed at other utilities that address DER and  
21      NWA scenario planning and automate many common tasks and reports run by  
22      engineers. Power Runner will be enhanced to provide more validation of load  
23      profiles and be integrated with the as-operated status of the system to better model  
24      load transfers and switching. Power Runner will also incorporate the  
25      subtransmission model hierarchy to allow for preparation of subtransmission

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1 loading data sets into tools like the commercial software, Power System Simulator  
2 for Engineering (PSSE). PSSE enhancements will be made in 2025 to comply with  
3 MISO MOD32 data modelling requirements and to perform new gross load  
4 calculations at model nodes. The commercial software SEEQ analytic tool will also  
5 be enhanced; this provides detailed data analysis capabilities to time series signals  
6 and allows for complex calculations for asset health and other engineering  
7 calculations.

8 2026 Enhancements will focus on improving DER and NWA analysis and enabling  
9 multi scenario analysis in the planning tools to facilitate short- and long-term  
10 planning of the system. 2026 investments will also begin to improve forecasting  
11 and propensity analysis of DER adoptions. These enhancements will lead to more  
12 accurate system studies, more efficient interconnection screens and studies and  
13 better optimized designs for system improvement, non-wire alternatives and  
14 loading projects. Customers will benefit from reduced interconnection study and  
15 review times and more accurate up front estimates of system upgrades.

16

### 17 **3. Interconnection Process Enablement**

#### 18 **Q166. What is the Interconnection Process Enablement program?**

19 A166. The Interconnection Process Enablement program represents investments focused  
20 on the software and interfaces for interconnection processing. The interconnections  
21 process is a regulatorily required process that evaluates a generator or distributed  
22 energy resource such as solar or a battery so that it can safely and reliably connect  
23 to the electrical system and meet tariff requirements. Interconnections requirements  
24 are based on MPSC rules and national standards organizations publications such as

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1 the Institute of Electrical and Electronics Engineers (IEEE) and Underwriters  
2 Laboratories (UL) as well as MISO and FERC requirements. Interconnection  
3 process enablement includes the integration of the interconnection portal with  
4 payment processing and customer facing web pages and investments in the  
5 interconnection tracking database and process engine, PowerClerk. Additional  
6 investments are made in tools and interfaces to streamline interconnection  
7 processing, study, and screening. This benefits customers by improving the  
8 application, screening, and study response times and accuracy. These investments  
9 are driven by changes to market programs, interconnection rules, standards,  
10 procedures, and tariffs. These enhancements also streamline the process of applying  
11 for and connecting DER.

12

13 **Q167. What investments did DTE Electric make in 2023 and 2024, and what are the**  
14 **benefits to customers of those investments?**

15 A167. In 2023 and 2024, the Company implemented online payment processing for  
16 interconnection fees and enabled single sign on login for customers, which allows  
17 them to access the interconnection portal with the same username and password as  
18 their DTE Electric online account. The Company also invested in cybersecurity  
19 enhancements to the single sign-on for PowerClerk and interconnection processing  
20 web pages. Other investments included improvements to PowerClerk integrations,  
21 forms, automation, website pages, and documentation to support the new  
22 interconnection rules initiated in Case No. U-20890. The Company also  
23 implemented changes to fee structures and online payment as part of the new rules.

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1 **Q168. What investments are planned in 2025 and 2026, and what are the benefits to**  
2 **customers of those investments?**

3 A168. Investments for 2025 and 2026, as shown in Exhibit A-12, Schedule B5.4, page 14,  
4 line 20, include enhancements to online payment and the interconnection portal and  
5 automations associated with the interconnection process for small interconnections.  
6 Additionally, the enhancements include back-end improvements to screening and  
7 study that will increase application throughput and reduce manual labor in  
8 preparing and running studies. Further updates and automation improvements will  
9 be done in 2025 and 2026 to comply with changes to interconnection procedures  
10 and inverter model reporting needed by MISO. The 2025 and 2026 investments will  
11 also streamline the screening and study process and initiate the implementation of  
12 FERC Order No. 2222 related application and screening processes into  
13 PowerClerk.

14

#### 15 **4. Hosting Capacity Enablement**

16 **Q169. What is the Hosting Capacity Enablement program?**

17 A169. The Hosting Capacity Enablement program includes improvements to the publicly  
18 available online map that displays hosting capacity on the DTE Electric system,  
19 and to the capabilities to compute hosting capacity and process the data to be  
20 publicly available.

21

22 **Q170. What investments did DTE Electric make in the Hosting Capacity Enablement**  
23 **Program in 2023 and 2024, and what are the benefits to customers of these**  
24 **investments?**

Line  
No.

1 A170. Investments in 2023 and 2024 included publishing loading capacity maps and  
2 developing streamlined interfaces for the hosting capacity map that allow for more  
3 frequent updates and analysis of more areas of the system. These maps allow  
4 customers to see the amount of remaining capacity and hosting capacity in their  
5 area.

6

7 **Q171. What investments are planned in 2025 and 2026, and what are the benefits to**  
8 **customers of those investments?**

9 A171. The Company's 2025 and 2026 investments are shown in Exhibit A-12, Schedule  
10 B5.4, page 14, line 19. In 2025 and 2026, the program will focus on integrating  
11 improved circuit analysis capabilities, which are being developed in the load  
12 forecasting and analytics project, into the outputs of the hosting and load capacity  
13 maps. This integration will result in a more detailed representation of hosting  
14 capacity values across numerous circuit sections. The increased granularity of data  
15 will provide customers with additional information, aiding their decision-making  
16 process.

17

## 18 **5. Power Quality Analysis Program**

19 **Q172. What is the Power Quality Analysis program?**

20 A172. The Power Quality Analysis program represents investments in software to  
21 centralize, collect, correlate, and visualize power quality data such as fault and  
22 disturbance waveforms, voltage disturbances, harmonics, flicker, and momentary  
23 information from various metering sources on the electrical system. The software  
24 provides analysis capabilities to help determine the root cause of events and begin



Line  
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1 to establish predictive capabilities from analysis of disturbances that have not yet  
2 created an outage or equipment issue.

3

4 **Q173. What investments has DTE Electric made in the program and what are the**  
5 **benefits to customers of those investments?**

6 A173. In 2024, the Company completed the implementation of the Power Management  
7 Expert (PME) solution for Schneider Ion Meters and implemented interfaces for  
8 wave form data from line sensors to a machine learning algorithm. The PME  
9 software allows for the streamlined collection of power quality data from over  
10 2,000 Ion Power quality meters installed on the system and provides data access to  
11 groups that directly support customers in planning and major account services as  
12 well as internal engineering and operations groups that analyze events. The  
13 waveform event identification project improves access to power quality events and  
14 is intended to begin the process of proactive failure identification from power  
15 disturbances that could lead to predictive maintenance programs in the future.

16

17 **Q174. What investments are planned in 2025 and 2026 and what are the benefits to**  
18 **customers of those investments?**

19 A174. The Company's 2025 and 2026 investments are shown in Exhibit A-12, Schedule  
20 B5.4, page 14, line 22. In 2025 and 2026, the Company will centralize power  
21 quality information into a single data set that can be analyzed and correlated with  
22 complaints, trouble events, and outages. The Company will also establish interfaces  
23 for near real time capture of power quality meter data and implement new reporting  
24 capabilities from existing Ion and Honeywell meters. Analysis tools and machine  
25 learning capabilities will be added to the system to determine root cause and begin

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1 the process of identifying precursors to predict failures and outages from sensor  
2 and power quality data.

3

4 **6. Substation and Structural Design Tool Upgrades Program**

5 **Q175. What is the Substation and Structural Design Tool Upgrades Program?**

6 A175. This program represents investments in design and structural calculation tools that  
7 are used by the Company's engineers, planners, and designers to implement  
8 standards and calculated physical analysis into designs prior to construction. This  
9 includes new tools to facilitate rapid compliance for pole and overhead structure  
10 calculations and steel work and enhancement to CAD design tools to improve  
11 integration into work management, scheduling, and cost estimating.

12

13 **Q176. What investments did DTE Electric make in 2023 and 2024, and what are the**  
14 **benefits to customers of those investments?**

15 A176. In 2023 and 2024, the Company procured structural design tools (*e.g.*, RISA3D and  
16 PLSCAD) and created compatible units for class A substation standards. The  
17 Company also completed testing of overhead structures with EPRI to validate  
18 structural design calculations and systematic testing of failure modes. These  
19 enhancements streamline the design process for planners and designers in selecting  
20 the appropriate equipment which will reduce timelines and the chance for errors.  
21 The testing has helped to inform design standards and adjustments to the  
22 construction methods will result in a more robust system.

23 **Q177. What investments are planned in 2025 and 2026, and what are the benefits to**  
24 **customers of those investments?**

Line  
No.

1 A177. The Company's 2025 and 2026 investments are shown in Exhibit A-12, Schedule  
2 B5.4, page 14, line 23. The 2025 investments include acquiring specialized  
3 structural modeling tools to allow for engineered structure designs to be verified.  
4 The Company will conduct additional structural design testing in 2025 to validate  
5 the modeled parameters in the software and update design standards accordingly.  
6 Additionally, in 2025 the Company will begin the process of updating the  
7 substation design tools and interfaces to utilize the compatible units and closely  
8 link design to the Maximo and supply chain process, and conduct initial work  
9 needed to align the design tools to the Utility Network model. In 2026 the Company  
10 will focus on the Utility Network model alignment to support design tool changes.  
11 These enhancements will further streamline design and allow for design tools to  
12 perform more automated checking and validation of designs and reduce  
13 conversions of data at handoffs between different design groups and vendors.

14

15 **7. Distribution Planning Program**

16 **Q178. What is the Distribution Planning Program?**

17 A178. The Distribution Planning Program was a collection of projects within the  
18 Distribution Planning OT category that represented a set of investments in 2023  
19 and 2024 that supported the scope of the other sub-programs in the Distribution  
20 Planning OT category. These investments are distinct work scope that was started  
21 before they were categorized into the Distribution Planning OT Category and the  
22 naming of the project and the rate case descriptive category is coincidental.

23

24 **Q179. What investments did DTE Electric make in this program in 2023 and 2024,**  
25 **and what are the benefits to customers?**

Line  
No.

1 A179. The following initiatives represent the significant investments in this program in  
2 2023-2024, as shown in Exhibit A-12, Schedule B5.4, page 14, line 24:

- 3 • CYME 9.2 license renewal and server hardware investment; the benefits of  
4 those investments are covered in the Load allocation and analytics and  
5 CYME Upgrade sections earlier in my testimony;
- 6 • Investments in systems that support the ADMS system to bring additional  
7 operational data to DTE Electric employees when responding to unplanned  
8 field events resulting in better overall control and effectiveness; and
- 9 • The Transformer Geographic Location Number (GLN) ReMap project.

10

11 **Q180. What is the purpose of the Transformer GLN ReMap project?**

12 A180. Accurate customer-to-transformer mappings are essential for ADMS to identify  
13 outage scopes effectively. Incorrect mappings can cause the following: delay  
14 outage restoration; create safety concerns for field crews working with incorrect  
15 connectivity data; lead to resource misallocation and inefficiencies in restoration  
16 efforts; and compromise data integrity, affecting downstream systems and  
17 operational planning.

18

19 The Transformer GLN ReMap project will develop an enhanced tool that integrates  
20 with the Company's SAP system to facilitate customer meter assignment to  
21 transformer, enabling near real-time transformer GLN re-assignment updates in the  
22 Outage Management System (OMS). This was a six-month project and was  
23 completed in December 2024.

24

25 **Q181. What are the benefits of this investment?**

Line  
No.

1 A181. The new tool will support safety and reliability. Accurate transformer connections  
2 reduce safety hazards for field crews, ensuring they address the correct equipment  
3 during outages and repairs. Additionally, improved connectivity ensures better data  
4 quality, enhancing the reliability of the distribution network and reducing outage  
5 durations. Reliable connectivity reduces unnecessary outages and voltage  
6 fluctuations and accurate mapping and assignment of customers to the correct  
7 feeders helps to enable timely restoration and prevent incorrect Estimated Time of  
8 Restoration (ETR) or cause codes.

9

10 **iii. Work Management and Scheduling**

11 **Q182. What is Work Management and Scheduling?**

12 A182. Work Management is a systematic approach used in many industries for tracking,  
13 measuring, and optimizing work processes to improve efficiency and reliability.  
14 The Company's investments in this area support the essential tools and  
15 technologies required to coordinate work on the distribution system from initiation  
16 through closeout of work orders. These investments enable the efficient assignment  
17 of labor, materials, and other tasks, such as timesheet management, while also  
18 facilitating job planning and execution. Additionally, the Company is investing in  
19 the deplatforming of outdated work management tools that pose security risks due  
20 to discontinued support, lack of updates, and vulnerability to cyber threats.  
21 Upgrading to modern, supported systems provides continued operational  
22 efficiency, security, and compliance with evolving industry standards. These  
23 investments are critical to maintaining a safe, reliable, and well-coordinated work  
24 environment.

Line  
No.

1 **Q183. Where are the capital investment details of the projects and programs in the**  
2 **Work Management and Scheduling category provided?**

3 A183. Capital investment details of the projects and programs in this category are  
4 provided in the following Exhibits:

- 5 • Exhibit A-12, Schedule B5.4, page 14 and 15; and
- 6 • Exhibit A-23, Schedule M7.

7

8 **Q184. Did the Audit address the Company's Work Management and Scheduling**  
9 **investments?**

10 A184. Yes, the Audit supported these investments, concluding that enhanced work  
11 planning and scheduling will prove critical to effective and efficient performance  
12 of the massive work levels facing DTE Electric.<sup>30</sup>

13

14 **1. Primary Service Orders Replatform**

15 **Q185. What is the purpose and scope for the Primary Services Replatform (PSO)**  
16 **project?**

17 A185. The Primary Services Replatform (PSO) project will develop a modern application  
18 for the Primary Service group to replace the legacy system that has been in use for  
19 the past 15 years. The Primary Services group provides services to Primary  
20 Customers (major industrial accounts), including installations, specifications,  
21 design and layout of high voltage equipment and systems. The current application  
22 is at end of life, resulting in decreased efficiency for internal Company end users.  
23 The legacy application's availability and frequent downtime negatively impact the  
24 Company's ability to deliver strong customer service. Additionally, the stand-alone

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<sup>30</sup> Case No. U-21305, [068cs00000AyaNpAAJ](#), Audit Report, Part Two at p. 93.

Line  
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1 nature of the legacy database creates integration challenges with dependent  
2 applications. Multiple logins across various systems lead to inefficiencies in  
3 workflow, impacting productivity. The following scope was identified for this  
4 investment shown in Exhibit A-12, Schedule B5.4, page 14, line 27:

- 5 • 2024 (Phase I): Planning, requirements elicitation, design, development,  
6 system integration testing, performance testing, data cleanup and migration,  
7 user acceptance testing, and production deployment.
- 8 • 2025 (Phase II): Complete data cleanup and migration, automate the  
9 creation of Work Orders in Maximo for Primary Operating Orders, and  
10 implement solutions for enhancements or issues identified during user  
11 acceptance testing (UAT).

12

13 **Q186. What are the benefits of this project?**

14 A186. The benefits of this project are:

- 15 • Improved customer service. Specifically, the new application will enhance  
16 service quality for both planned and unplanned outages through accurate  
17 and easily accessible data.
- 18 • Improved safety with easy-to-access data, like site drawings, which will aid  
19 operations teams doing the work.
- 20 • Streamlined Integration: The new database integrates customer billing data  
21 in SAP, creating a direct link between billing and physical customer  
22 locations, improving processes for new construction, power quality  
23 complaints, and billing accuracy.

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- 1 • Database Consolidation: It combines three existing databases (customer
- 2 details, operating order requests, and historical sketch files), all of which
- 3 are at end-of-life.
- 4 • Enhanced Data Availability: The new database will display onsite customer
- 5 generation and demand load, enabling faster responses to primary
- 6 customers during outages.

7

## 8 **2. External Crew Efficiency**

### 9 **Q187. What is External Crew Efficiency?**

10 A187. External Crew Efficiency is a category of capital investments intended to efficiently  
11 and cost-effectively utilize external contract crews to augment Company crews.  
12 The capability to utilize external crews efficiently and cost-effectively is a key  
13 component to improving the speed and efficiency of storm restoration. The projects  
14 in this investment category are: 1) Utility Restoration Management Application  
15 (URMA) in years 2023-2026; and 2) Enterprise Timesheet System (ETS) in years  
16 2024 and 2025.

17

### 18 **Q188. What is the purpose and scope of the Utility Restoration Management** 19 **Application (URMA)?**

20 A188. The URMA is a web-based solution designed to centralize vendor roster  
21 management and streamline work assignment processes. It enables vendor crews to  
22 receive, update, and report on their assignments in real time. URMA transforms  
23 manual processes into systematized workflows, enforcing contractual requirements  
24 and enabling real-time data capture and review. The estimated timeline and scope  
25 for the project include:



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- 1           • 2023:
- 2               ○ Initial discovery and design.
- 3           • 2024:
- 4               ○ Developed functionality for Foreign Crew vendors to build rosters
- 5               with valid crew classifications and equipment checks.
- 6               ○ Enabled DTE Electric administrators to approve rosters, assign
- 7               crews to storm yards and Emergency Field Leads (EFLs), and
- 8               manage crew check-ins/outs at storm yards.
- 9               ○ Expanded functionality to include Tree Trim vendors.
- 10          • 2025:
- 11               ○ Extend rostering to Baseload, Local Foreign, and Underground
- 12               crews.
- 13               ○ Enhance and automate Electric Field Leader (EFL) assignments.
- 14               ○ Improve storm crew management, including baseload assignments
- 15               and crew tracking.
- 16          • 2026:
- 17               ○ Expand URMA to DTE Electric crews (Overhead/Underground,
- 18               Public Protection, Damage Assessment).
- 19               ○ Integrate URMA with the Enterprise Timesheet System (ETS) for
- 20               detailed timesheet management.

21

22   **Q189. What are the benefits of URMA?**

23   A189. The benefits of URMA include:

- 24           • Improved contract administration, such as:
- 25               ○ Confirming proper crew classifications and equipment;

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- 1                   ○ Confirming crew qualifications, crew size, and crew configurations;
- 2                   and
- 3                   ○ Optimizing crew size.

4           Qualitative benefits of URMA include:

- 5           • Outage duration reduction: URMA supports the Company's goal of
- 6           reducing outage restoration times by accelerating roster management,
- 7           improving assignment accuracy, providing real-time work progress
- 8           tracking, as well as eliminating delays and manual inefficiencies.
- 9           • Improved coordination: By standardizing processes, URMA improves
- 10          coordination across teams and provides seamless access to crew rosters and
- 11          work progress, which enhances overall service quality.
- 12          • Improved Customer Experience: Faster, more accurate storm restoration
- 13          processes leading to reduced outage times.
- 14          • Enhanced Communication: Real-time updates allow DTE Electric to
- 15          provide more timely and accurate restoration information to customers and
- 16          stakeholders.
- 17          • Increased Reliability: Consistent processes during storm events improve
- 18          resource management, planning, and execution.

19

20   **Q190. What is the purpose and scope for the Enterprise timesheet system (ETS)**  
21   **project?**

22   A190. The ETS project is an initiative to replace the current timesheet application (VTS)  
23   used by Tree Trim, Overhead, and Underground vendors. The VTS application,  
24   which processes approximately \$500 million annually in vendor spend across these  
25   operations, runs on IBM's MobileFirst platform, which will reach end of life in

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1 September 2025. Without a replacement, the application would become  
2 unsupported after IBM discontinues the MobileFirst platform, posing significant  
3 operational and financial risks. Currently, there is no backup application for VTS,  
4 and a failure of the platform would compromise critical functions, including billing  
5 and crew rostering. The ETS project began in early 2024 and delivered a minimum  
6 viable product (MVP) in 2024. Full replacement with feature parity to VTS was  
7 released in March 2025.

8  
9 **Q191. What are the benefits of this project?**

10 A191. The ETS project will provide the following benefits:

- 11 • Real-time spending insights for the Strategy and Billing teams, which aids  
12 budget planning and vendor payments;
- 13 • Over 95% unbilled line item (UBL) accuracy at month-end, reducing errors  
14 and improving financial processes;
- 15 • Enablement and utilization of custom logic for data inaccuracies and  
16 correction by the Company and vendors, improving operational efficiency;
- 17 • Enhanced accuracy and electronic data management, which provides timely  
18 and accurate vendor payments.;
- 19 • Electronically stored timesheet data, which supports future spend projection  
20 and budget planning;
- 21 • Alignment with DTE Electric's URMA rostering functionality, which  
22 enhances integration across systems; and
- 23 • Future scalability and functionality enhancements to support additional  
24 internal business groups, such as Emergency Preparedness & Response  
25 (EP&R) and the Project Management Office (PMO).

Line  
No.

1    **3. Substation Report and Process Enhancements**

2    **Q192. What is the purpose and scope of the Substation Report and Process**  
3       **Enhancements project?**

4    A192. The objective of this 2024 project was to develop modern, user-friendly query tools  
5       that enable teams to efficiently combine, query, and analyze data related to  
6       equipment (locations and assets), Work Orders, Inspections, Actual Cost Data, and  
7       other critical information from Maximo, SAP, and ESRI. Additionally, nine web  
8       reporting tools were migrated from the outdated “DO Reports” web application,  
9       that was built on Classic ASP, to ASP.NET.

10

11       The old reporting tools relied on outdated Classic ASP technology that Microsoft  
12       has stopped developing and supporting, resulting in security vulnerabilities. This  
13       arrangement did not align with the Company’s strategy of adopting modern, cloud-  
14       based solutions where appropriate. This upgrade ensures alignment with modern IT  
15       platforms and provides a foundation for future enhancements.

16

17   **Q193. What are the benefits of the Substation Report and Process Enhancements**  
18       **project?**

19   A193. The benefits of this project include real-time access to asset and operational data  
20       (equipment, inspections, work orders, inventory, costs, failure data, etc.), which is  
21       essential for making informed decisions about repairs, replacements, and root cause  
22       analysis. Understanding equipment performance and work history helps prevent  
23       costly, unexpected maintenance.

Line  
No.

1 **4. Vegetation Management Replatform**

2 **Q194. What is the purpose and scope of the Vegetation Management replatform?**

3 A194. The purpose of the Vegetation Management replatform is to replace the existing  
4 vegetation management software, which will reach end-of-life support in March  
5 2027. The Vegetation Management replatform will improve data management and  
6 scalability. To facilitate uninterrupted vegetation management operations, the  
7 Company must transition to a modern, SaaS-based, vendor-hosted solution that  
8 provides a reliable, end-to-end work management process. The project is scheduled  
9 to begin in 2026 and is currently planned for two years. This replatforming effort  
10 will cover all four phases of vegetation management:

- 11 • Initiation: Identifying prior work, prioritizing circuits based on vegetation  
12 density and line mileage, and tracking historical work mileage.
- 13 • Planning: GIS-based vegetation planning, customer approval tracking, and  
14 work categorization based on species, ownership, and safety factors.
- 15 • Execution: GIS-based tracking of daily work productivity, work approvals,  
16 and crew progress.
- 17 • Audit/Close: Tracking completed work, identifying defects, sending tasks  
18 for rework, and maintaining historical data for reporting.

19 The new solution will integrate with PowerBI, Smartsheets, and email automation  
20 tools to enhance efficiency and reporting. Transitioning to a modern SaaS-based  
21 solution will provide the necessary reliability, scalability, and integration  
22 capabilities to continue managing vegetation effectively.

23

24 **Q195. What are the benefits of the project?**

25 A195. The key benefits of the Vegetation Management Replatform project include:

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- 1 • Reliability: Anticipated improvement of productivity in trimming and
- 2 removing vegetation, ensuring better system performance.
- 3 • Safety: Increased efficiency in vegetation management reduces the
- 4 likelihood of tree-related damage to electrical assets during storms.
- 5 • Faster identification and resolution of problem areas: The application will
- 6 automatically synchronize data within minutes and enable field users to
- 7 focus on vegetation management tasks.
- 8 • Employee Engagement: The new system will enhance coordination
- 9 between employees and customers, improving overall engagement.
- 10 • Accelerated Innovation: Near-real-time data synchronization and system
- 11 updates will allow the vegetation management program to stay aligned with
- 12 evolving business needs.

13

14 **Q196. What alternatives, including not executing the Vegetation Management**  
15 **Replatform project, did the Company consider?**

16 A196. The only alternative option is to continue using the current application on an  
17 unsupported basis past its end-of-life date of March 2027. This approach carries  
18 significant risks, including increased security vulnerabilities, lack of vendor  
19 support, and the inability to resolve issues internally.

20

21 **Q197. What would be the consequences of not completing the Vegetation**  
22 **Management Replatform project?**

23 A197. Failure to implement a new system before the current solution reaches end of life  
24 could lead to operational disruptions, including loss of data visibility, inability to  
25 track work progress, loss of ESRI support, and potential work stoppages.

Line  
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1 **5. Mobile Time Sheets**

2 **Q198. What is the purpose and scope for the Mobile Time Sheets project?**

3 A198. The Mobile timesheet (MTS) project will replace the outdated and unsupported  
4 mobile timesheet application used by Overhead and Underground crews for nearly  
5 20 years with a new application. The current application supports only time entries  
6 and does not allow for attribution of time worked to individual tasks. Set to begin  
7 in 2026 and finish in 2027, the new application will streamline payroll, budgeting,  
8 and integration with SAP and Maximo.

9

10 **Q199. What are the benefits of this project?**

11 A199. This project will incorporate asset data in addition to time entries, improve cost  
12 tracking, and minimize errors by pre-populating asset and work order details.  
13 Seamless integration with SAP and Maximo will eliminate manual corrections,  
14 which will save time for field employees and supervisors.

15

16 **Q200. What alternatives, including not executing the Mobile Time Sheet project, did**  
17 **the Company consider?**

18 A200. The only alternative is to not execute the project and continue to use the  
19 unsupported application.

20

21 **Q201. What would be the consequences of not completing the Mobile Time Sheet**  
22 **Project?**

23 A201. Persisting with the aging system would result in ongoing payroll errors and  
24 administrative burdens. The existing application, which crews cannot use on mobile  
25 devices, also uses a rigid 15-minute increment formatting that contributes to time

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1 entry errors. Combined with delays in interfacing with Maximo and SAP, this leads  
2 to frequent payroll inaccuracies and requires several hours of corrections each  
3 week. Upgrading to a modern, automated solution will provide cleaner data, reduce  
4 payroll corrections, and allow frontline employees and their supervisors to focus on  
5 field operations rather than fixing errors.  
6

## 7 **6. Work Management and Scheduling Upgrades**

### 8 **Q202. What are the Work Management and Scheduling Upgrades?**

9 A202. The Work Management and Scheduling Upgrades program represents a collection  
10 of projects that further support and upgrade the essential tools and technologies  
11 required to coordinate work on the distribution system, with a focus on upgrading  
12 outdated applications, renewing licenses, and automating manual processes.  
13

### 14 **Q203. Were any of these projects completed during the 2023 historical test year?**

15 A203. Yes. The following Work Management and Scheduling Upgrades projects were  
16 completed during 2023:

- 17 • ARCOS license renewal:
  - 18 ○ DTE has utilized the ARCOS Callout solution for several years,  
19 necessitating frequent license renewals. The Company successfully  
20 negotiated a comprehensive five-year (2023-2028) agreement,  
21 preventing year-over-year cost increases and ensuring elevated  
22 warranty support throughout the period.
  - 23 ○ This solution is crucial for the Substations group to conduct after-  
24 hours callouts while adhering to collective bargaining agreements  
25 and union rules. The five-year agreement ensures the continuity of



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1 an operational callout system, maintaining efficiency and reliability  
2 in managing after-hours dispatching for the Substations group.

3 ○ For customers, the timely dispatch and subsequent system  
4 restoration facilitated by ARCOS decrease the number and duration  
5 of substation-related outages.

6 • Primavera refresh:

7 ○ Primavera is the scheduling software used by the DO Scheduling  
8 and Project Management Office (PMO) Groups. This project  
9 upgraded the outdated, unsupported version of Primavera Scheduler  
10 to Maxavera, an industry-standard integration product for Primavera  
11 and Maximo, transitioning the system from an on-premise to a  
12 cloud-based solution.

13 ○ The previous Primavera version was 16 major revisions behind and  
14 no longer supported by the vendor, posing security risks and  
15 operational inefficiencies. The upgrade eliminated data latency  
16 between Primavera and Maximo, improved interoperability with  
17 DTE Energy's corporate project management office, mitigated  
18 security vulnerabilities, reduced system downtime, and provided  
19 seamless schedule integration and project management across the IT  
20 organization.

21 • DO Field Operations Tools Automation:

22 ○ This project replaced outdated operational tools, applications, and  
23 dashboards that could no longer support evolving operational  
24 processes.

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1                   ○ Many DO applications relied on legacy technologies, increasing  
2                   maintenance costs and inefficiencies. Several systems that measure  
3                   day-to-day performance were dependent on manual steps and did  
4                   not have a consistent approach to data management. Report  
5                   generation was not consistent between groups/regions/service  
6                   centers, which led to process inefficiencies and reduced situational  
7                   awareness. The project automated manual efforts, reducing reliance  
8                   on spreadsheets for operations management.

9                   ○ Increasing automation in these activities increased visibility into  
10                  process adherence, helped identify gaps, and improved situational  
11                  awareness post ADMS go live in 2023.

12                  • Crew Management Enhancements:

13                  ○ This project spanned 2022-2023 and improved DTE Electric's crew  
14                  resource management systems and processes. Infrastructure  
15                  upgrades improved workforce management by enhanced crew  
16                  visibility, automated overtime and training tracking, streamlined  
17                  administrative processes, incorporation of union contract  
18                  adjustments, and integration of apprentice rostering without manual  
19                  intervention.

20                  ○ In 2023, the Company implemented further enhancements,  
21                  including a dedicated training environment, Fleet Organization  
22                  integration for calendaring, and expanded management-level  
23                  reporting. The training environment allows users to gain hands-on  
24                  experience beyond initial training, improving system utilization and  
25                  efficiency.

Line  
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1 **iv. Asset Management**

2 **Q204. What is Asset Management?**

3 A204. Asset Management is a sub-category of OT investments that enable the Company  
4 to utilize technology to effectively manage both physical (*e.g.*, personal protective  
5 gear and large fleet vehicles) and IT assets.  
6

7 **Q205. Where are the capital investment details of the Asset Management projects  
8 and programs provided?**

9 A205. Capital investment details of the projects and programs in the Asset Management  
10 category are provided in the following Exhibits:

- 11 • Exhibit A-12, Schedule B5.4, page 14-15; and
  - 12 • Exhibit A-23, Schedule M7.
- 13

14 **1. Asset Failure Analytics**

15 **Q206. What is the purpose of the Asset Failure Analytics project?**

16 A206. The purpose of the Asset Failure Analytics project is to improve the Company's  
17 ability to proactively identify and replace assets at risk of failure, reducing  
18 unplanned outages and reactive maintenance costs. This initiative will leverage  
19 advanced machine learning (ML) and artificial intelligence (AI) models to enhance  
20 the accuracy of DTE Electric's asset replacement strategy. Many utilities are  
21 adopting advanced analytics and AI-driven asset management strategies to improve  
22 reliability and cost-effectiveness. This project aligns with industry trends by  
23 incorporating data-driven decision-making into asset management practices,  
24 ensuring the Company remains proactive in maintaining a resilient grid.

Line  
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1 **Q207. What is the scope of the Asset Failure Analytics project?**

2 A207. During 2026 the project will focus on the Underground Residential Distribution  
3 (URD) cable project due to its critical role in the reliability of the distribution  
4 system. The purpose of the URD project is to provide the Distribution Operations  
5 team the ability to leverage data in order to effectively prioritize and optimize the  
6 URD cable replacement program, which is described further in Witness Robinson's  
7 testimony.

8

9 There are two primary types of work performed by the URD Replacement Program:  
10 (1) prioritizing and replacing existing URD cable and (2) replacing live-front  
11 underground (UG) transformers (described below) with dead-front UG  
12 transformers.

13

14 The scope of the project will include creating a model that will identify likelihood  
15 of cable failures and hazards, which will help streamline execution of the following  
16 year's replacement plan.

17

18 **Q208. What benefits and alternatives, including not executing the Asset Failure**  
19 **Analytics project, did the Company consider?**

20 A208. To improve the prioritization of selecting URD cable locations for replacement, the  
21 Company evaluated several approaches before selecting the machine learning  
22 algorithm. The Company explored standard methods, such as linear interpolation,  
23 but found them unsuitable due to the type and volume of data. The Company also  
24 considered maintaining current processes but determined them to be incomplete.

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1 **Q209. What would be the consequences of not executing the Asset Failure Analytics**  
2 **project?**

3 A209. If the Company does not execute this project, it would continue to utilize the current  
4 methodology for identifying system cable for replacement, without the added  
5 benefits of the machine learning algorithm to optimize the prioritization process.

6

7 **2. Cable Failure Analytics**

8 **Q210. What is the purpose and scope of the Cable Failure Analytics project?**

9 A210. The purpose of the Cable Failure Analytics project is to provide the Distribution  
10 Operations team the ability to accurately calculate the probability of failure for  
11 underground electrical system cable to more effectively prioritize and optimize the  
12 cable replacement program, as described in Witness Robinson's testimony. The  
13 project's 2025 scope includes the creation of a failure prediction model utilizing a  
14 machine learning algorithm that will estimate the probability of a cable failing and  
15 provide a prioritized list of cables that need replacement.

16

17 **Q211. What benefits and alternatives, including not executing the Cable Failure**  
18 **Analytics project, did the Company consider?**

19 A211. To improve the prioritization of selecting system cable locations for replacement,  
20 the Company evaluated several approaches before selecting the machine learning  
21 algorithm. These alternatives were assessed based on their feasibility, cost,  
22 effectiveness, and alignment with long term goals. Using a third-party vendor  
23 offers expertise but can be costly and limits control over the process and data  
24 security. Non-machine learning approaches, such as deterministic algorithms, were  
25 considered but found ineffective due to data limitations, inefficiency, and

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1 scalability issues. Machine learning was chosen for its ability to identify patterns  
2 and insights that traditional methods might miss.

3

4 **Q212. What would be the consequences of not executing the Cable Failure Analytics**  
5 **project?**

6 A212. If the Company does not execute this project, it would continue to utilize the current  
7 methodology for identifying system cable for replacement, without the added  
8 benefits of the machine learning algorithm to optimize the prioritization process.

9

10 **3. ESRI Utility Network Proof of Concept**

11 **Q213. What is the purpose of the ESRI Utility Network Proof of Concept project?**

12 A213. The Environmental Systems Research Institute (ESRI) Geographic Information  
13 System (GIS) for geospatial data and analysis provides location information for DO  
14 assets, including electrical distribution assets such as poles. The ESRI Utility  
15 Network Proof of Concept project is a critical new initiative designed to transition  
16 from the soon-to-be unsupported ESRI ArcMap to the advanced ESRI Utility  
17 Network (UN) system. ArcMap is one of the main applications within the ArcGIS  
18 Desktop suite developed by ESRI used by the Company for geospatial data,  
19 including electrical asset distribution, and analysis. The main impetus for this  
20 project is the scheduled deprecation of ESRI ArcMap, which entered Mature  
21 Support on March 1, 2024, and will be fully retired by March 1, 2026. This project  
22 will assess and prepare the Company's current Geometric Network (GN) ArcGIS  
23 and ArcFM GIS data for migration to the UN framework.

24

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1   **Q214. What is the scope of the Proof of Concept project?**

2   A214. The proof of concept ESRI project involves a comprehensive review and design of  
3       the Company's existing GIS architecture and data quality and establishment of a  
4       test environment to facilitate a subset data migration.

6   **Q215. What are the benefits of the ESRI Utility Network Proof of Concept project?**

7   A215. This preparatory phase is essential to identify and mitigate potential data issues  
8       prior to full-scale ESRI Utility Network implementation, providing a seamless  
9       transition and continued support for the Company's GIS infrastructure. The  
10      successful execution of the initial phase is a prerequisite for this conversion, as it  
11      addresses all potential challenges, facilitating a smooth and efficient transition to  
12      the new system as this change impacts the core model for the NMS, ADMS, all  
13      planning tools, and any other system utilizing location-based data for distribution  
14      assets.

16   **Q216. What alternatives, including not executing the Proof of Concept project, did  
17       the Company consider?**

18   A216. The Company evaluated other GIS products, but none offered the comprehensive  
19      capabilities, features, or utility-specific focus necessary to manage GIS data as  
20      effectively as the ESRI Utility Network. The ESRI Utility Network is the optimal  
21      solution for the Company's needs.

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1 **Q217. What would be the consequences of not executing the Proof of Concept**  
2 **project?**

3 A217. Failure to execute the proof of concept project would miss the opportunity to lay a  
4 successful foundation for the ESRI Utility Network conversion and could increase  
5 the risk of an unforeseen implementation challenge delaying the conversion project  
6 discussed below.

7

#### 8 **4. ESRI Utility Network Model Upgrade**

9 **Q218. What is the purpose of the ESRI Utility Network Model Upgrade project?**

10 A218. Building upon the insights gained from the ESRI Utility Network Proof of Concept  
11 (ESRI UN POC) project, the ESRI Utility Network Conversion project will  
12 complete the comprehensive migration from ESRI ArcMap to the Utility Network  
13 system.

14

15 **Q219. What is the scope of the ESRI Utility Network Model Upgrade project?**

16 A219. This project is a three-year initiative projected to start in 2026. The project  
17 encompasses data cleanup, full-scale migration, and integration with critical  
18 systems such as ADMS/OMS, CYME, CRANE, iDMS, Maximo, ArcFM  
19 Designer, ArcFM Mobile, CRM/ISU, and PTM.

20

21 **Q220. What are the benefits of the ESRI Utility Network Model Upgrade project?**

22 A220. The transition to Designer 11, a part of the ArcFM solution suite designed to  
23 streamline the design and construction processes for utilities and facilitate the  
24 transition to modern utility networks, will enhance the efficiency of updating GIS  
25 data from field operations, moving away from manual, paper-based processes to



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1 streamlined digital workflows. The Company's GIS is the system of record for all  
2 spatial assets within the Electric Distribution, Gas Distribution, and Gas  
3 Transmission units. Maintaining business continuity in these areas is essential to  
4 serve customers and communities efficiently and responsibly. Ensuring the GIS's  
5 reliability and integration with other critical systems is vital for maintaining service  
6 quality and operational excellence.

7

8 **Q221. What alternatives, including not executing the project, did the Company**  
9 **consider?**

10 A221. As discussed above, alternative GIS products were assessed; however, none  
11 matched the capabilities, features, or utility-specific design required to manage the  
12 Company's GIS data effectively. The ESRI Utility Network and Designer 11  
13 provide the most robust and future-proof solutions for DTE Electric's needs.

14

15 **Q222. What would be the consequences of not executing the ESRI Utility Network**  
16 **Model Upgrade project?**

17 A222. Not executing the project would leave the Company to rely on obsolete software,  
18 leading to increased costs for limited support and exposing DTE Electric's existing  
19 GIS systems to security risks. Providing for the GIS's reliability and integration  
20 with other critical systems is vital for maintaining service quality and operational  
21 excellence. Continuing to use software that will be unsupported in the near future  
22 could lead to significant costs and security vulnerabilities due to the lack of updates  
23 and technical support. Transitioning to the ESRI Utility Network will move DTE  
24 Electric's GIS to a modern, fully supported product and aligns with industry  
25 standards.

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1 **5. LIDAR and Imagery Analysis Platform**

2 **Q223. What is the purpose of the LIDAR and Imagery Analysis Platform project?**

3 A223. The purpose of the Company's investment in LIDAR and imagery processing is to  
4 leverage the capabilities of machine learning to analyze large volumes of visual  
5 imagery and LIDAR data that can be captured from satellites, aircraft, drones, and  
6 field crews to improve the quality of electrical infrastructure data and assess the  
7 field condition of assets automatically. A platform is needed to process this  
8 information as it is collected to provide actionable information for damage  
9 assessment, asset health assessment and many other future use cases that rely on  
10 comprehensive information about the condition of the electrical system.

11

12 **Q224. What is the scope of the project?**

13 A224. In 2025 an initial proof of concept will be conducted to assess the capabilities of a  
14 LIDAR analysis system, how new data sets are loaded, and the opportunities for  
15 integration to other systems like the GIS and analytics tools. In 2026 the project  
16 will procure and implement a commercially available LIDAR analysis platform and  
17 create interfaces to process LIDAR data and route analysis to the mapping GIS and  
18 the NMS system to support network model data quality and enhancements.  
19 Interfaces will also be created to consolidate LIDAR and visual imagery captured  
20 from the field to link Asset Health and Asset Management systems and utilize  
21 machine learning algorithms to process the images to determine asset condition or  
22 damage. Investment is expected to continue through 2028 to complete the  
23 implementation of the platform.

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1 **Q225. What are the benefits of the LIDAR and Imagery Analysis Platform project?**

2 A225. The benefit of capturing visual imagery and processing it with machine learning is  
3 improved outage damage assessment and assessment of the asset health of overhead  
4 structures and equipment by allowing the Company to evaluate a larger area and  
5 identify problems and root causes. The benefit of LIDAR is the ability to precisely  
6 determine the location and geometry of distribution assets, including the class and  
7 height of a pole, how much it leans, the equipment and configuration of wires on  
8 the pole, and clearance to vegetation and obstructions including evaluating  
9 conductor sag and spacing. This highly precise data can be processed into types of  
10 equipment that will allow for multiple potential opportunities beyond improving  
11 asset location data. This includes structural assessment of poles and wire loading,  
12 identification of broken or damaged assets, evaluation of clearances to hazards, and  
13 improving mapping data on the connectivity of wires. LIDAR data can also be used  
14 to create highly accurate models of substations and structures that can then be used  
15 to improve design.

16

17 **Q226. What alternatives, including not executing the project, did the Company**  
18 **consider?**

19 A226. While this type of technology could be left unexplored, the Company has conducted  
20 substantial benchmarking as to how other utilities use visual imagery, machine  
21 learning, and LIDAR to improve the condition assessment of their system and has  
22 seen that the technology is viable and bringing results to entities that have started  
23 to use it. If the Company does not implement this technology, a valuable source of  
24 information to improve restoration times and detect damaged equipment would be  
25 left unutilized. Additionally, while it would be possible to do specialized, one-off

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1 projects for specific use cases, without an investment to standardize and consolidate  
2 the information into a single point of visualization many very similar projects  
3 would be needed that would use essentially the same IT backends. This approach  
4 would require users to go to multiple locations to get a complete picture.

5

6 **6. ADMS/GMS Hardware**

7 **Q227. What is the purpose of the ADMS/GMS Hardware project?**

8 A227. The project involves replacing the server and storage infrastructure that supports  
9 the ADMS (Advanced Distribution Management System) and GMS (Generation  
10 Management System) systems to maintain system functionality and prevent the  
11 hardware from reaching end of life (EOL).

12

13 **Q228. What is the scope of the project?**

14 A228. The hardware purchased in 2018—comprising all of GMS and part of ADMS—  
15 will reach end of life in April 2028. To address this issue, the investment will be  
16 implemented over three years, beginning in 2026. It will include deployment of a  
17 new architecture platform, upgrade to the latest operating system releases and  
18 licenses, infrastructure enhancements, and labor support for installation,  
19 configuration, and migration of the current application suite. In 2026, the scope of  
20 work includes procuring new GMS hardware (servers, routers, switches, cabinets,  
21 and other infrastructure components) and upgrading the associated operating  
22 systems.

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1 **Q229. What are the benefits of the ADMS/GMS Hardware project?**

2 A229. This investment will modernize and expand the ADMS and GMS systems'  
3 capabilities on a new architectural platform, providing continued operation beyond  
4 the current hardware's EOL.

5  
6 **Q230. What alternatives, including not executing the project, did the Company  
7 consider?**

8 A230. No real alternatives exist other than permitting the ADMS and GMS systems to  
9 reach end of life and continue to be used while unsupported.

10

11 **Q231. What would be the consequences of not executing the project?**

12 A231. If the Company does not proceed with this project, the ADMS and GMS systems  
13 will reach the end of their lifecycle, missing out on enhanced functionalities and  
14 support provided by updated hardware and operating systems, while also facing  
15 potential NERC compliance and DOE fines and cybersecurity risks. In addition,  
16 cybersecurity risk increases with the continued use of unsupported equipment.

17 **v. Mobile Technology**

18 **Q232. What is Mobile Technology?**

19 A232. Mobile Technology is a category of OT investments focused on creating seamless  
20 transitions between on-line and off-line operations and providing integrated  
21 communication between the control room, field leaders, field crews, and supporting  
22 organizations. Mobile capabilities include devices and applications that are  
23 engineered for mobile access and usage. Applications include dispatch, work

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1 execution and forms digitization, location tracking, route navigation, analytics, and  
2 secure file sharing.

3

4 **Q233. Where are the capital investment details of the projects and programs in the**  
5 **Mobile Technology category of OT investments?**

6 A233. Capital investment details of Mobile Technology projects and programs are  
7 provided in the following Exhibits:

- 8 • Exhibit A-12, Schedule B5.4, page 14-15; and
- 9 • Exhibit A-23, Schedule M7.

10

11 **Q234. Did the Audit address the Company's Mobile Technology investments?**

12 A234. Yes, the Audit concluded that these investments are consistent with capabilities  
13 now commonly recognized as critical to maintaining effective communications and  
14 promoting effective and timely dispatch fieldwork efficiency and data accuracy.<sup>31</sup>

15

## 16 **1. Mobile Tools Expansion**

17 **Q235. What is Mobile Tools Expansion?**

18 A235. Mobile Tools Expansion is a category of investments related to tools and  
19 applications utilized by field personnel to improve the efficiency, productivity, and  
20 safety of the crews' work. The primary investment in this category is the Every Day  
21 Daily Plan (EDDP).

---

<sup>31</sup> Case No. U-21305, [068cs00000AyaNpAAJ](#), Audit Report Part Two, p. 93.

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1 **Q236. What is the purpose and scope of the Every Day Daily Plan (EDDP) project?**

2 A236. The Everyday Daily Plan (EDDP) is a web-based application designed to  
3 consolidate all emergent and planned work on the electric system in real time. This  
4 project aims to create a best-in-class solution for Distribution Operations by  
5 collaborating with numerous stakeholders and establishing a standardized process  
6 that consistently meets user needs and expectations regardless of outage conditions.

7 The estimated timeline and scope of the EDDP project includes:

8 • 2023:

9 ○ Developed the Prioritization and Grouping Logic for emergent  
10 work.

11 ○ Automated the first assignment of jobs.

12 • 2024:

13 ○ Added planned work alongside emergent work on the electrical  
14 system.

15 ○ Developed contingency plans for technology failures to ensure  
16 seamless continuation of day-to-day operations with the application.

17 ○ Integrated with the Crew Management System.

18 ○ Automated crew assignments.

19 • In 2025 and 2026 the EDDP project will:

20 ○ Automate the next job assignment by deploying a trigger  
21 mechanism to automate the initiation of continuous assignments for  
22 prompt task assignments to crews without manual input.

23 ○ Enhance work routing for the teams with Distribution Operations  
24 like the planned work routing for EFO and Scheduling and emergent  
25 work routes for Tree Trim.

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- 1                   ○ Integrate with Field Mobile tools such as Field Service Edge and
- 2                   Outage status app for efficient task assignments for crews and
- 3                   contractors.
- 4                   ○ Integrate Circuit walkdowns with the EDDP.

5

6   **Q237. What are the benefits of the EDDP project?**

7   A237. The EDDP offers both qualitative and quantitative benefits to customers:

8                   • Quantitative Benefits:

- 9                   ○ The development of EDDP saved 13,000 crew hours in 2024. This
- 10                  significant increase in crew productivity translates directly into
- 11                  faster service restoration times. Shorter outage durations mean that
- 12                  customers experience less inconvenience and disruption.
- 13                  ○ In 2024, the EDDP accounted for a savings of 69 minutes each
- 14                  during Storm and Blue Sky days; reducing the time to get crews
- 15                  assigned and dispatched to their first job by approximately 1 hour
- 16                  per crew.

17                  • Qualitative Benefits:

- 18                  ○ Improved efficiency and faster response times; customers will
- 19                  benefit from more reliable service and quicker resolution of outages.
- 20                  ○ Additionally, the integration of planned work with trouble work
- 21                  facilitates seamless maintenance and upgrades, leading to fewer
- 22                  unexpected outages and a more stable electric system.
- 23                  ○ By efficiently managing and executing planned maintenance and
- 24                  upgrades, the project contributes to a more resilient and sustainable



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1 electric grid. This proactive approach to grid management helps  
2 prevent outages and provides a more reliable power supply.

3 ○ The project promotes operational excellence by standardizing  
4 processes and improving coordination among different teams during  
5 all weather conditions. This standardization helps to maintain high-  
6 quality service delivery and brings all internal stakeholders onto the  
7 same page, leading to more efficient and effective operations.

8 ○ The Company has set goals for achieving reductions in SAIDI and  
9 a 48-hour target for storm response. The EDDP supports this goal  
10 by streamlining operations and reducing the time it takes for crews  
11 to respond to and resolve outages. By automating job assignments  
12 and integrating various systems, the project helps crews move more  
13 quickly from one job to the next without unnecessary delays.

14

## 15 **2. ADMS: DMS/OMS Mobile Tool**

### 16 **Q238. What is the ADMS DMS/OMS mobile tool?**

17 A238. The ADMS DMS/OMS mobile tool is the mobile tool offered by the ADMS  
18 vendor. This tool enables more safe and efficient operations of the electric grid by  
19 better integrating field and office personnel while responding to emergent and  
20 trouble work.

21

22 For more information on the state of DTE Electric's current mobile tool and its  
23 replacement, please refer to Witness Ambrose's testimony under the heading Field  
24 Service Edge (FSE) Replacement – ClickSoft.

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1   **Q239. What are the benefits of the ADMS DMS/OMS mobile tool?**

2   A239. The benefits of the ADMS DMS/OMS mobile tool are largely related to field crew  
3       situational awareness. The mobile tool will enable field crews to view and interact  
4       with the ADMS as-operated network model, eMap, providing them with improved  
5       situational awareness. This will enable them to make faster, more informed  
6       decisions based on the real-time configuration of the electric grid as opposed to  
7       their current tools that show the as-designed electric grid.

8  
9       The tool will also facilitate improved communication between field crews and the  
10      DTE Electric control room. Like ADMS both will be working from an integrated  
11      platform, so communication will become smoother and more efficient. For  
12      example, field and office personnel will be able to observe the same as-operated  
13      map with the same DMS and OMS information at the same time. This foundational  
14      situational awareness will enable more efficient operations.

15  
16     The mobile tool will also bring additional benefits as other ADMS-related functions  
17     become operationalized. For example, the results and recommendations from  
18     FLISR will be available to field crews via the mobile tool, which will assist in  
19     realizing the benefits of fault location estimation. Additionally, with the  
20     implementation of SOM and the mobile tool, field crews will be able to look at the  
21     same switching and tagging steps as control room personnel, which is a significant,  
22     novel improvement in the switching and tagging process.

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1     **3. Enhance and Expand Cybersecurity**

2     **Q240. What is the purpose and scope of the Enhance and Expand Cybersecurity**  
3         **project?**

4     A240. The Company plans to make significant investments in its grid automation  
5         programs over the next decade. Grid assets and infrastructure must be safeguarded  
6         against cyber attacks. This project will deploy targeted hardware and software  
7         technologies to implement and strengthen cybersecurity policies and processes  
8         within the Company's infrastructure. This deployment will be conducted in a  
9         controlled manner to test and evaluate the most effective strategies to address these  
10        threats. This program establishes policies and procedures and monitoring tools that  
11        the Substation Cybersecurity Program discussed above implements for physical  
12        security for stations like Stone Pool. The estimated project timeline and scope  
13        include:

- 14        • 2024:
  - 15           ○ Conducted an Asset Inventory Pilot in 10 Substations to identify
  - 16           assets and assess data collection methods.
  - 17           ○ Evaluated monitoring tools and recommended a cyber tool for
  - 18           vulnerability and threat detection.
  - 19           ○ Updated the OT Cybersecurity Standard Document.
  - 20           ○ Created and updated standard work instructions
  - 21           (SWIs)/Policies/Procedures linked to each OT Cybersecurity
  - 22           Standard for consistent response to cybersecurity situations.
- 23        • 2025 and 2026:
  - 24           ○ Manage asset inventory for an additional 180 substations by end of
  - 25           2026.

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- 1                   ○ Procure and install a monitoring tool to identify vulnerabilities and
- 2                   threats in 15% of substation assets.
- 3                   ○ Establish and maintain a dedicated cybersecurity team to collaborate
- 4                   with the Cyber Security Defense Center (CSDC) within the
- 5                   Information protection and Security (IPS) team to address cyber
- 6                   threats.
- 7                   ○ Update the OT Cybersecurity Standard Document, which
- 8                   establishes a comprehensive framework for the secure, efficient, and
- 9                   reliable management of OT systems to ensure enterprise-wide
- 10                  alignment.
- 11                  ○ Create and update SWIs, policies, and procedures to increase the
- 12                  National Institute of Standards and Technology (NIST)<sup>32</sup>
- 13                  Cybersecurity framework score (CSF), which assesses an
- 14                  organization's cybersecurity risk, by 2027.

15

16   **Q241. What are the benefits of the Enhance and Expand Cybersecurity Project?**

17   A241. Properly understood and implemented tools and countermeasures will make the

18       grid reliable, available, and defensible. Customers will benefit from a more resilient

19       and efficient grid. Additionally, this project will limit access and control of the

20       automation that is put in place to only the authorized operators, which is critical for

21       both safety and operational effectiveness.

---

<sup>32</sup> The National Institute of Standards and Technology (NIST) develops cybersecurity standards, guidelines, best practices, and other resources to meet the needs of U. S. industry, federal agencies and the broader public.

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1     **4. Mobile Equipment Replacement**

2     **Q242. What is the purpose and scope of Mobile Equipment Replacement project?**

3     A242. The Company has deployed thousands of mobile devices to field personnel and  
4           their leadership. These devices have planned useful deployed lifecycles of six years.  
5           The Company plans and executes device replacements yearly on ~1/6th of those  
6           devices to keep them operational and secure.

7

8     **Q243. What are the benefits of Mobile Equipment Replacement?**

9     A243. Upgrading to current technology maintains reliable access to critical applications,  
10          enhances communication, and aligns with the Company's commitment to safe and  
11          efficient grid management. Up to date devices are more reliable and technically  
12          secure from cyber threats than older, less capable equipment. It is important for  
13          field personnel to have operational and up-to-date equipment to perform their work  
14          functions safely and effectively. This benefits customers as it improves DTE  
15          Electric's ability to respond to service needs and helps shorten outage restoration  
16          times.

17

18    **5. Mobile Technology**

19    **Q244. What are the Mobile Technology projects?**

20    A244. This additional category of Mobile Technology enhancements projects represents  
21          a collection of projects that includes WiFi upgrades, mobile work tools, and  
22          licenses for mobile apps. The following investments completed during 2023  
23          provide remote access and secure mobile workflows to support a more agile  
24          workforce:

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- 1 • Service Center Wi-Fi Upgrades: The Service Center Wi-Fi Upgrade project  
2 enhanced wireless infrastructure across 15 locations, including the Warren  
3 Service and Technical Development Centers. This initiative expanded indoor  
4 coverage and added outdoor access in parking areas, truck bays, and garages,  
5 (which can function as work staging areas and “offices” for employees and  
6 contractors at these sites) addressing increased demand from mobile devices.  
7 These improvements enable field personnel to efficiently access necessary  
8 applications and data, supporting the Company’s 48-hour storm restoration  
9 commitment by accommodating increased device usage during such events.  
10
- 11 • Lemur Pro Multiyear License Purchase: In 2023, the Company completed a  
12 three-year renewal of Lemur Pro licenses. Lemur Pro, developed by Locana, is  
13 an application that provides OH/UG/PSR field resources with access to As-  
14 Built maps of the electrical system, including equipment attributes, in both  
15 connected and offline modes. This renewal provides cost stability and  
16 continued warranty support, allowing crews to visualize work locations relative  
17 to circuits, equipment, and other teams, thereby enhancing operational  
18 efficiency.  
19
- 20 • Field Service Edge Overhead (OH)/Underground (UG) Enhancements: The  
21 Field Service Edge (FSE) project, launched in February 2023, introduced a  
22 mobile application for electric field operations (EFO) and Overhead and  
23 Underground crews. FSE facilitates the reception of trouble job assignments  
24 and associated details, streamlining workflows. Post-launch, additional features  
25 were integrated to align with the Company’s 48-hour storm restoration goal,

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1 including consolidated input screens, assignment prioritization grids, bulk  
2 updates, and enhanced mapping of crew assignments. These enhancements  
3 improve situational awareness, expedite routine tasks, and ensure data quality,  
4 thereby bolstering the efficiency of storm response efforts.

5

6 **Q245. What are your thoughts concerning the Company's approach to and**  
7 **investments in DTE Electric's Distribution Operations Technology and**  
8 **Automation Pillar?**

9 A245. The investments supported by my testimony will enable the Company to  
10 reasonably, prudently, and effectively utilize the most current technologies to  
11 modernize its grid and achieve greater safety, reliability, and efficiency to the  
12 benefit of the Company's customers. The Company has thoughtfully and  
13 deliberately evaluated the programs and projects in the Technology and  
14 Automation Pillar to reasonably and prudently modernize its grid over time and the  
15 Commission should approve recovery of the investments to do so.

16

17 **Q246. Does this complete your direct testimony?**

18 A246. 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-21860

QUALIFICATIONS  
AND  
DIRECT TESTIMONY  
OF  
JASON D. DE STIGTER



**DTE ELECTRIC COMPANY**  
**QUALIFICATIONS AND DIRECT TESTIMONY OF J. DE STIGTER**

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1    **Background & Qualifications**

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

3    A1.    My name is Jason D. De Stigter. My business address is 9400 Ward Parkway, Kansas City,  
4           Missouri 64114. I am employed by 1898 & Co. as the Director of Utility Investment  
5           Planning in our Utility Consulting Practice.

6  
7    **Q2.    On whose behalf are you testifying?**

8    A2.    I am testifying on behalf of DTE Electric.  
9

10   **Q3.    Please generally describe the work of 1898 & Co.**

11   A3.    1898 & Co. was established in 2019 as the consulting division of Burns & McDonnell  
12           Engineering Company, Inc. ("Burns & McDonnell"). 1898 & Co. is a nationwide network  
13           of nearly 500 consulting professionals serving the Manufacturing & Industrial, Oil & Gas,  
14           Power Generation, Transmission & Distribution ("T&D"), Transportation, and Water  
15           industries.

16  
17           Burns & McDonnell was established in 1898 and serves multiple industries, including the  
18           electric power industry. Burns & McDonnell is a family of companies comprising more  
19           than 13,500 engineers, architects, construction professionals, scientists, consultants, and  
20           entrepreneurs, with more than 75 offices across the country and throughout the world.

21

22   **Q4.    Please describe your educational background and professional experience.**

23   A4.    I received a Bachelor of Science degree in Engineering and a Bachelor of Business  
24           Administration degree from Dordt College, now called Dordt University. Prior to joining  
25           1898 & Co. and Burns & McDonnell, I served as a Principal Consultant at Black & Veatch

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1 in their Asset Management Practice, where I performed risk and resiliency studies. I am a  
2 registered Professional Engineer in the State of Kansas. My full resume is attached hereto  
3 as Exhibit A-28 Schedule R1.

4  
5 I am a professional engineer with 16 years' experience providing consulting services to  
6 electric utilities. Through my work at 1898 & Co. and Burns & McDonnell, I have  
7 developed extensive experience in asset management, capital planning and optimization,  
8 risk/resiliency assessments and analysis, asset failure analysis, and business-case  
9 development for electric utilities. I have been involved in numerous studies modeling risk  
10 for utility clients, including economic analyses for several multi-billion-dollar capital  
11 projects and large utility systems. In my role as a Director of Utility Investment Planning,  
12 I have worked on and overseen risk and resiliency consulting studies on a variety of electric  
13 T&D assets. I have a focus on developing risk and resiliency-based investment models for  
14 large capital projects/programs.

15  
16 **Q5. Have you previously sponsored testimony before the Michigan Public Service**  
17 **Commission (MPSC or Commission)?**

18 A5. I have not testified before the Michigan Public Service Commission. I have testified before  
19 on similar benefit cost analysis as is described in my testimony. A complete list of  
20 testimonies I have provided before other regulatory bodies is included with Exhibit A-28  
21 Schedule R1.

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1 **Purpose & Overview**

2 **Q6. What is the purpose of your direct testimony?**

3 A6. DTE Electric engaged 1898 & Co. to perform a benefit cost analysis (BCA) for four  
4 distribution investment programs included within this rate case filing. The four programs  
5 include:

- 6 1. Pole and Pole Top Maintenance & Modernization (PTMM)
- 7 2. Strategic Undergrounding Pilot
- 8 3. Distribution Automation (DA)
- 9 4. Grid Automation Telecommunications

10

11 The purpose of my testimony is to 1) outline the approach employed to perform the benefit  
12 cost analysis as well as investment identification for the PTMM and Distribution  
13 Automation programs (Resilience, Reliability, & Risk-Based Planning Approach and Grid  
14 Automation Telecommunication Approach sections), 2) to summarize the results of the  
15 benefit cost analysis for each of the programs (Benefit cost Analysis Results section) and  
16 3) provide my conclusions (Summary and Conclusions section).

17

18 Specifically for the Grid Automation Telecommunication program, my testimony shows  
19 the purpose of benefit cost analysis is to provide investment stakeholders with information  
20 to understand which system wide telecommunication solution provides the most benefits  
21 to DTE Electric customers. It is not the purpose of this evaluation to identify the preferred  
22 local strategy, rather the purpose of this evaluation is to identify the preferred system wide  
23 or global strategy. The benefit cost analysis is focused on identifying the solution that is  
24 most preferred at the system level. I recognize that local or particular investments may be  
25 lower cost but don't align to the system level preferred solution.

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1 My direct testimony introduces, summarizes, and incorporates by reference the Program  
2 Benefit Cost Analysis Report developed as part of that effort.

3

4 **Q7. Are you sponsoring any exhibits in this proceeding?**

5 A7. Yes. I am sponsoring the following exhibits:

| <u>Exhibit</u> | <u>Schedule</u> | <u>Description</u>                           |
|----------------|-----------------|----------------------------------------------|
| 6 A-28         | R1              | Resume of Jason D. De Stigter with –         |
| 7              |                 | List of Prior Regulatory Testimony           |
| 8 A-28         | R2              | Integrated Resilience, Reliability, & Risk – |
| 9              |                 | Investment Model                             |
| 10 A-28        | R3              | Program Benefit Cost Analysis Report         |
| 11 A-28        | R4              | OH to UG Model – Attica – Confidential       |
| 12 A-28        | R5              | OH to UG Model – Spruce – Confidential       |

14

15 **Q8. Was your testimony and these exhibits prepared by you or under your direction?**

16 A8. Yes, they were.

17

18 **Q9. Can you please describe your involvement in performing the benefit cost analysis for**  
19 **these four programs?**

20 A9. I served as the 1898 & Co. project director for the DTE Electric BCA performed at my  
21 direction by 1898 & Co. In that role, I worked directly with DTE Electric's team in the  
22 development and justification of the benefit cost analysis. Specifically, I was responsible  
23 for the overall 1898 & Co. engagement and involved in the creation and direction of the  
24 development of each benefit cost analysis. I was also directly involved in developing the

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1 Integrated Resilience, Reliability, and Risk Investment model that was utilized to perform  
2 the benefit cost analysis.

3

4 **Q10. What were the objectives for the BCA?**

5 A10. The objectives for the benefit cost analysis were to:

6 1. Quantify the improvement expected for individual DTE Electric distribution  
7 investment activities and programs, specifically estimating benefits from a customer  
8 centric perspective, mainly avoided future costs to repair or replace assets and value  
9 of reduction in customer outages;

10 2. Demonstrate the expected improvement in the number and duration of customer  
11 outages for certain DTE Electric distribution programs; and

12 3. Identify and prioritize the DTE Electric distribution investments with the highest  
13 quantified benefit per dollar invested into the DTE Electric system.

14

15 **Q11. How does the BCA achieve these objectives?**

16 A11. To achieve these objectives, I utilized a resilience, reliability, and risk-based planning  
17 approach using 1898 & Co.'s proprietary Integrated Resilience, Reliability, and Risk  
18 Investment Model. The model employs a data-driven decision-making methodology  
19 utilizing sophisticated algorithms to calculate the resilience, reliability, and risk mitigation  
20 benefit of investments by identifying the expected range of reduced duration and frequency  
21 of customer outages, measured as Customer Minutes Interrupted (CMI), and reduced  
22 outage restoration costs. The benefit cost approach and model facilitates the identification  
23 of distribution investments that provide the most benefit to DTE Electric's customers.  
24 Prioritizing and optimizing investments in the electric delivery system helps provide

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1 confidence that the overall investment level is appropriate and that customers will get the  
2 most value for the level of investment.

3

4 **Resilience, Reliability, & Risk-Based Planning Approach**

5 **Q12. Can you provide a brief overview of the resiliency, reliability, and risk-based planning**  
6 **approach?**

7 A12. A resilience, reliability, and risk-based planning approach was used to identify, prioritize,  
8 and perform a benefit-cost analysis to support the investment justification for the four DTE  
9 Electric distribution investment programs outlined above. This approach incorporates  
10 historical data, sophisticated algorithms, and a suite of analytics models inside the  
11 Integrated Resilience, Reliability, and Risk Investment Model to estimate the Resilience,  
12 Reliability, and Risk benefit cost ratio (BCR) for each potential DTE Electric distribution  
13 investment activity. The Integrated Resilience, Reliability, and Risk Investment Model is  
14 a propriety model built by 1898 & Co. Benefits are estimated from a customer perspective  
15 and shown in terms of the: (1) the decrease in the frequency and impact of customer  
16 outages, calculated as CMI; (2) monetization of the decrease in CMI utilizing the U.S.  
17 Department of Energy (DOE) ICE Calculator; and (3) decrease in restoration costs.

18

19 **Q13. Has 1898 & Co. utilized this approach and model in other regulatory filings?**

20 A13. Yes, 1898 & Co. has utilized this same planning approach and corresponding model in  
21 several other states and regulatory jurisdictions. Exhibit A-28 Schedule R1 includes details  
22 on each of these cases with links to the various dockets. In summary, 1898 & Co. has  
23 utilized this planning approach and corresponding model across eight jurisdictions and 13  
24 utility operating companies. In seven of these jurisdictions, over \$7 billion of T&D

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1 investment has been approved by commissions or settled upon by intervening parties. Each  
2 of the cases utilized the modeling results for prudence evaluation.

3  
4 **Q14. Have any of these commissions publicly commented on the 1898 & Co. Resilience,**  
5 **Reliability, and Risk investment planning process and model?**

6 A14. Yes, the Public Utility Commission of Texas has utilized 1898 & Co. modeling approach  
7 and model to approve over \$4 billion of System Resiliency Plans (SRP) for three different  
8 utilities: Oncor, Entergy Texas, and Texas-New Mexico Power (TNMP). These are  
9 currently the only plans the commission has approved. Four other SRPs are pending  
10 approval, two of which 1898 & Co. supported and performed the benefit cost evaluation.  
11 At the first open hearing meeting, October 24, 2024, to discuss the first system resiliency  
12 plan for Oncor, Commissioner Jimmy Glotfelty, said the following about 1898 and Co.'s  
13 analytic model: "First I want to say, coming right out of the box, I was impressed with the  
14 analytics behind what 1898 [and Co.] put together....but the fact that they are steeped in  
15 utilizing data and models to help solve and slice and dice the data to figure out where to go  
16 and what to do I think is a valuable tool."<sup>1</sup> At the following open hearing meeting on  
17 November 14<sup>th</sup>, 2024 Commissioner Glotfelty reiterated his support of 1898 and Co.'s  
18 analytic model saying: "I believe that the consulting firm that they [Oncor] used, 1898 [and  
19 Co.] grounded this plan in metrics and in data."<sup>2</sup> These public comments show that the  
20 1898 & Co. modeling approach and model (the same one utilized in this proceeding) have  
21 provided confidence to the Texas Public Utility Commission to approve over \$4 billion of  
22 electric distribution investment in hardening, pole inspections, distribution automation,

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<sup>1</sup>Open Meeting at 09:30 AM. 01:32:12-1:32:45 (2024). Public Utility Commission of Texas. Retrieved April 14, 2025, from [https://www.adminmonitor.com/tx/puct/open\\_meeting/20241024/](https://www.adminmonitor.com/tx/puct/open_meeting/20241024/).

<sup>2</sup>Open Meeting at 09:30 AM. (2024). 00:57:05-00:57:23, Public Utility Commission of Texas. Retrieved April 14, 2025, from [https://www.adminmonitor.com/tx/puct/open\\_meeting/20241114/](https://www.adminmonitor.com/tx/puct/open_meeting/20241114/).

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1 telecommunication enhancements, technology implementation, and physical / cyber  
2 security investment.

3

4 **Q15. Can you please describe the Integrated Resilience, Reliability, & Risk Investment**  
5 **Model?**

6 A15. The Integrated Resilience, Reliability, & Risk Investment Model employs a data-driven  
7 decision-making methodology using robust and sophisticated algorithms to calculate the  
8 resiliency, reliability, and risk benefits for each potential investment activity that makes up  
9 the PTMM and Distribution Automation programs I discuss above. It uses a suite of  
10 modules to assess the expected costs and benefits of specific resiliency investments. The  
11 model first includes foundational data, including DTE Electric's distribution asset register  
12 and equipment characteristics, which are used to determine the unique vulnerabilities of  
13 DTE Electric's system. Core to the model is the linkage between the infrastructure and the  
14 specific customers it serves. Specifically, the model builds the direct linkage between each  
15 asset on the DTE Electric system and the number and types of customers that would be  
16 impacted if the asset were to fail. This information feeds the rest of the model. An  
17 illustration of the Integrated Resilience, Reliability, & Risk Investment Model is attached  
18 as Exhibit A-28 Schedule R2.

19

20 **Q16. How is the Integrated Resilience, Reliability, & Risk Investment Model structured?**

21 A16. The model first includes foundational data, including DTE Electric's asset register and  
22 equipment characteristics, which are used to determine the unique vulnerabilities of DTE  
23 Electric's system. Core to the model is the linkage between the infrastructure and the  
24 specific customers it serves. Specifically, the model builds the direct linkage between each



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1 asset on the DTE Electric system and the number and types of customers that would be  
2 impacted if the asset were to fail. This information feeds the rest of the model.

3  
4 The model includes two analytics models (Outage Mitigation Model, and Equipment  
5 Failure Mitigation Model). Each of these analytics models estimates the expected avoided  
6 costs and avoided customer outages. Each analytics model was designed to estimate the  
7 resilience, reliability, and risk benefits of different investments based on the available data,  
8 asset types, benefit streams, and failure types. I describe each of these analytics models in  
9 more detail later in my testimony.

10  
11 Finally, the model includes a plan-development module that integrates the benefit-cost  
12 results from each of the analytics models and captures investment activity-bundling  
13 approaches to maximize the efficiency of DTE Electric's implementation. This module's  
14 output is a list of investment activities for DTE Electric to develop an executable plan that  
15 balances maximizing customer benefits and execution constraints for each of the applicable  
16 DTE Electric programs.

17  
18 **Q17. What type of technology platform is the model built upon?**

19 A17. As noted above, the modeling employs sophisticated and complex calculations managing  
20 and integrating large datasets. As such, it is not a Microsoft Excel based model. The  
21 Resilience, Reliability, and Risk Investment Model is within a suite of technology  
22 applications including an Extract Transform and Load (ETL) tool, SQL database, and,  
23 where applicable, Python scripts are all managed through a tool called KNIME. This type  
24 of technology platform, as opposed to Microsoft Excel, is not only appropriate but  
25 expected. Firstly, the grid is a complex system, so to perform the type of detailed customer-

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centric benefit cost analysis to evaluate the grid investments requires a tool that can more accurately model this complex system. Secondly, the modeling includes cleansing, organizing, and integrating large datasets into an integrated data model and performing robust and sophisticated calculations on that data model to calculate each potential project's benefit cost ratio. These large data sets include hundreds of thousands of records and in some cases well over a million records which exceed the limits of Microsoft Excel. A robust technology tool is needed to perform the type of data extraction, transformation, integration and sophisticated customer-centric benefit cost analytics to perform an asset, investment activity (grouping assets together), and circuit level evaluation. This type of modeling tool and platform is both appropriate and expected.

**Q18. What is the Resilience, Reliability, and Risk BCR?**

A18. The Resilience, Reliability & Risk BCR, as used in this analysis, is a single value that represents complex modeling of resiliency and reliability failure modes, infrastructure vulnerability, infrastructure rebuild costs, and other financial factors to provide a robust and reliable measure to evaluate individual investments from a quantified customer benefit perspective. This single value, Resilience, Reliability & Risk BCR, for each DTE Electric distribution circuit, substation, and program level constitutes a sophisticated multi-factored analysis. This approach makes the BCR value a robust and reliable measure to help understand the justification for DTE Electric distribution investment activities.

**Q19. Are there other benefit streams for these DTE Electric distribution investments that are not included in the quantified benefit cost analysis?**

A19. Yes, while the Resilience, Reliability & Risk BCR incorporates many factors, it does not capture all benefit streams. BCR incorporates most of the objective related factors within

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1 the quantified benefits assessment. There are more subjective or difficult-to-quantify risk  
2 factors that have not been incorporated into the evaluation. Key subjective factors are  
3 safety, areas of lower performance (e.g. Customers Experiencing Multiple Interruptions or  
4 CEMI), and cyber-security risks, including the risk that new regulations require additional  
5 cyber-security investment. The Resilience, Reliability & Risk BCR should be utilized as a  
6 key tool in prioritizing and selecting investments in concert with other criteria that  
7 incorporate benefits streams not included within the quantified evaluation as described  
8 above. Incorporating quantitative and qualitative assessments together is a powerful  
9 decision-making tool for utility investments.

10  
11 **Q20. Can you please provide additional details on the foundational data utilized in the**  
12 **Integrated Resilience, Reliability, & Risk Investment Model?**

13 A20. The Integrated Resilience, Reliability, & Risk Investment model primarily relied on  
14 operational data from DTE Electric's Outage Management System ("OMS"), customer  
15 data (e.g., customer type and location) from DTE Electric's Customer Information System  
16 ("CIS"), system data from DTE Electric's Geographic Information System ("GIS"), pole  
17 and pole top inspection data from historical inspections, and asset information from DTE  
18 Electric's asset register. Various other data sources were used to identify accessibility from  
19 public roadways and vegetation density.

20  
21 **Q21. How does the Equipment Failure Mitigation model calculate the resilience, reliability,**  
22 **and risk benefits of investments?**

23 A21. The Equipment Failure Mitigation modeling approach calculates the benefits of replacing  
24 existing infrastructure. It forecasts the probability-weighted consequence of failure for a  
25 range of failure types. The failure types are based on how assets fail over their lifecycle,

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1 including inspection-based failures. Consequences are estimated for a range of factors but  
2 fall into two main categories. The first category is reactive or restoration costs. The second  
3 category is customer-based outages. This category is the monetization of customer outages  
4 in the event of an asset failure. This modeling approach was utilized for the PTMM  
5 program for both the groundline and pole top sub-projects. Further, the Grid Automation  
6 Telecommunication BCA utilized the end-of-life curve methodology that is part of this  
7 analytics model. Additionally, the underlying concepts from this analytics model were  
8 utilized in the Strategic Undergrounding Pilot BCA.

9  
10 The approach calculates each asset's lifecycle reactive costs and customer outage costs for  
11 two scenarios. The first is a Status Quo scenario where the asset is not proactively replaced;  
12 the second scenario is the Investment scenario in which the asset is upgraded proactively  
13 to the new equipment standard. The benefit of replacing infrastructure is the difference  
14 between the two scenarios, the avoided resilience, reliability, and risk lifecycle costs. This  
15 analysis provides a clear calculation of expected benefits from implementation of specific  
16 investments on the DTE Electric system.

17  
18 **Q22. How does the Outage Mitigation Model calculate the resilience, reliability, and risk**  
19 **benefits of investments?**

20 A22. The Outage Mitigation Modeling Approach utilizes the historical DTE Electric OMS data  
21 and recalculates each outage assuming the investments were originally in place. The  
22 approach fundamentally assumes future outages will be like historical outages. On average,  
23 this assumption is appropriate for performing the benefits assessment for investments. This  
24 modeling approach was utilized for the DTE Electric Distribution Automation Program;

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1 additionally, components of it were utilized for the Company's Strategic Undergrounding  
2 Pilot BCA.

3  
4 Using each outage's recalculated Customers Interrupted (CI) and CMI, the DOE ICE  
5 Calculator monetizes the mitigated outages by considering the types of customers  
6 impacted, count of customers impacted, and outage duration. The lifecycle present value  
7 of avoided customer outages is calculated by adjusting for inflation and discount rate over  
8 the lifecycle of the investment. This produces a lifecycle present value of benefits that can  
9 be directly compared to the cost of the investment through the BCR.

10  
11 **Q23. How does the Strategic Undergrounding Model calculate the resilience, reliability,**  
12 **and risk benefits of investments?**

13 A23. Similar to the Equipment Failure Mitigation Modeling approach, the Strategic  
14 Undergrounding Model calculates the benefits of replacing or extending the life of existing  
15 infrastructure, leveraging an asset-centric, bottom-up approach. The BCA models  
16 developed for Case No. U-21534 in 2024 were utilized with additional enhancements to  
17 perform the analysis for the strategic undergrounding program. The approach forecasts the  
18 probability-weighted consequences of aging infrastructure. The models capture three main  
19 categories of cost-based consequences that a given investment option can mitigate: reactive  
20 costs, cyclical program costs and customer outages, including customer outage costs. The  
21 Strategic Underground Model compares three investment alternatives to the baseline or  
22 status quo; the three investment alternatives evaluated are PTMM, Overhead Rebuild, and  
23 Underground Conversion.

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1 The models for Attica and Spruce have been included as Exhibit A-28, Schedules R4 and  
2 R5, respectively. These files include the two main enhancements to further incorporate  
3 resiliency benefits to the BCA models. The original model in Case No. U-21534 utilized  
4 historical data from the OMS to estimate the frequency and duration of future outages. Ten  
5 years of historical outage data are used in the analysis; however, severe weather may be  
6 even less frequent than once every ten years. To model these high-impact, low-probability  
7 events, the model now includes a simulated 1 in 20-year event and a 1 in 50-year event.  
8 These events include multi-day outages that can occur due to widespread failures across  
9 the entire system due to a major event. The second improvement was to incorporate a  
10 higher cost of longer duration outages for customers. The model used for Case No. U-  
11 21534 was conservative in extrapolating the ICE Calculator for longer-duration outages.  
12 To incorporate a higher cost for these outages, a continuation of the slope of the ICE  
13 Calculator was used to extrapolate for longer-duration outages.

14  
15 **Q24. What are the benefits of the Resilience, Reliability, and Risk-based planning**  
16 **approach to evaluating investments?**

17 A24. This approach has several benefits:

- 18 1. **It is comprehensive.** The evaluation includes nearly all the assets on DTE  
19 Electric's overhead distribution system to identify opportunities for investments.  
20 By considering and evaluating the entire distribution system on a consistent basis,  
21 the results of the Integrated Resilience, Reliability, and Risk Investment Model  
22 provide confidence that portions of DTE Electric's' distribution assets are not  
23 overlooked for potential customer benefit.
- 24 2. **It is customer focused.** The approach involved breaking DTE Electric's system  
25 into protection zones with a known number and type of customers. Protection zones

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1 are established based on the nearest upstream protective device. The failure of a  
2 single asset downstream of a protective device can cause a customer outage in that  
3 protection zone. Thus, aggregating assets into protection zones and evaluating  
4 investment activities at that level enabled the evaluation to provide a direct link  
5 between investments in vulnerable infrastructure and the benefits to customers.

6 3. **It is asset centric.** The granularity of modeling at the asset level and identifying  
7 for replacement of vulnerable equipment allows DTE Electric to invest in portions  
8 of the system that provide the most value to customers, as measured by the  
9 monetization of the reduction in the frequency and duration of customer outages  
10 and avoided system restoration costs. With the number of assets in the DTE Electric  
11 system and the numerous types of failure events that impact the service area, careful  
12 choices must be made to prioritize investments.

13 4. **It drives Consistency.** The modeling calculates benefits consistently for all  
14 investment activities, estimating both the monetized avoided customer outages and  
15 avoided reactive costs. The model carefully normalizes for a more accurate  
16 comparison of potential benefits between investment types. This provides  
17 additional confidence in the benefit cost analysis across the four DTE Electric  
18 distribution programs.

19 5. **It is rooted in the causes of equipment failures.** The model incorporates how  
20 assets fail and their different drivers as well as consequences. The detailed data  
21 streams and algorithms within the model are aligned with how assets fail – mainly  
22 vegetation density and asset age. Additionally, it incorporates additional drivers of  
23 asset consequence for rear-lot infrastructure and makes allowances for geography.  
24 This aligns the modeling to engineering based principles of infrastructure failure.

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1           6.     **It is practical.** This approach balances robust historical data with DTE Electric's  
2                   operational expertise to estimate benefits for investments that will have a practical  
3                   impact. Data-only approaches may identify solutions that work in theory but not in  
4                   practice. This approach balances the two approaches to identify investments that  
5                   will have a practical impact.

6  
7   **Q25. You have noted that the 1898 & Co. model employs robust and sophisticated**  
8           **algorithms to calculate the benefits for each of the potential investments, what**  
9           **approaches have you used to explain how the model works?**

10 A25. As noted above, the model is not a Microsoft Excel tool, rather it utilizes a tool called  
11 KNIME. We strive to enable understanding and to provide transparency on how the  
12 Integrated Resilience, Reliability, & Risk Investment Model is structured, organized,  
13 operated, and utilized. To meet this objective, we have employed several approaches. First,  
14 we have provided several exhibits associated with my testimony. Exhibit A-28 Schedule  
15 R1 includes links to all the previous cases that modeling approach has been leveraged.  
16 Exhibit A-28 Schedule R2 includes an illustration of the model structure. Schedule A-28  
17 Schedule R3, the Program Benefit Cost Analysis Report includes a more detailed review  
18 of the model and modeling approach. The report includes a more detailed review of the  
19 various data streams that feed the model and how they are related. Further it includes  
20 example calculations of foundational analytics including graphical representation of the  
21 approach around these analytics engines. Second, we regularly host technical conferences  
22 with intervening parties showing them the model, providing a demonstration of  
23 calculations, and answering additional questions beyond those provided in discovery. We  
24 have hosted these technical conferences for the following cases, links provided in Exhibit  
25 28 Schedule R1: AEP Ohio for their gridSMART Phase 3 DACR (Distribution Automation



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Circuit Reconfiguration) plan in 2024, Baltimore Gas & Electric (BGE) for their Multi-Year Plan in 2023, Entergy Louisiana for their 10 year Resiliency Plan in 2022, Oklahoma Gas & Electric (OG&E) for their Grid Enhancement Business Case in 2022, and Tampa Electric in their Storm Protection Plan filing in 2020. The intervenors in these technical conferences often include the state's designated public intervenor and their technical consultants. The Wired Group, one of the supporting technical consultants to the designated public intervenors, has been a part of technical conferences hosted by 1898 & Co. in the AEP Ohio, BGE, and OG&E cases outlined above.

**Q26. Are you willing to host a technical conference for interested parties in this case?**

A26. Yes, in the interest of transparency, we are willing to host a technical conference, in person or virtually, to walk through the Resilience, Reliability, and Risk Investment Model and each major component for interested parties, subject to appropriate protection under the protective order issued in this case.

**Grid Automation Telecommunication Approach**

**Q27. Why wasn't the Integrated Resilience, Reliability, and Risk Investment model used to evaluate the Grid Automation Telecommunication comprehensive evaluation?**

A27. The nature of telecommunications systems investments is different than the other investment types. It is important to understand these differences when performing and evaluating a benefit cost analysis for utility telecommunications investment. There are four key differences to understand.

First, utility telecommunications systems are enabling investments. The PTMM, Overhead to Underground, and Distribution Automation benefit cost analysis are direct benefit-based

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1 investments. Telecommunications systems are enabling or pre-requisite investments for  
2 utilities. Benefits, especially customer-driven benefits, can only be achieved if this  
3 investment is already in place and then additional direct investments are made. Further, a  
4 key factor in enabling investments and a benefit cost analysis is least cost analysis to  
5 understand which investment scenario has the lowest life-cycle costs. As such, an indirect  
6 benefit cost analysis approach was used with the lowest life-cycle cost methodology to  
7 evaluate the BCA of communication investments.

8  
9 Second, it is important to have an established “North Star” or long-term preferred solution  
10 on which to evaluate specific telecommunications investments. Re-investment risk is a  
11 major concern with telecommunications investments. While one investment might have  
12 the lower immediate costs, its life-cycle costs could be much higher because the investment  
13 is misaligned to the long-term preferred solution. Without an established long-term  
14 preferred solution, a BCA of a specific investment is challenging because the re-investment  
15 risk is not well understood. For this reason, the telecommunication benefit cost analysis  
16 considered several long-term preferred solutions.

17  
18 Third, the long-term preferred solution provides the best benefits versus costs on the global  
19 scale but that does not necessarily mean it is the best solution for every specific location.  
20 It was recognized that local investment optimization will still need to occur, however this  
21 needs to be done when it is necessary to make the investment in the local area. Since the  
22 telecommunications investment is done over a longer period of time, it is challenging to  
23 identify the preferred local solution across the entire system since conditions change.

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1 Fourth, the nature of sunk costs must also be understood when evaluating the preferred  
2 local solution. While one particular investment may show to be the preferred alternative,  
3 sunk costs at the system level may need to be excluded from evaluation of the benefits and  
4 costs of a local or particular investment. This can fundamentally change the preferred local  
5 alternative.

6  
7 **Q28. What approach was employed to evaluate the Company's Grid Automation**  
8 **Telecommunication program?**

9 A28. Five global scenarios were evaluated based on a conceptual structure and design provided  
10 by DTE Electric. Those five scenarios are:

- 11 1. Current Communications System (TropOS + Public LTE)
- 12 2. Public LTE (Current Capacity)
- 13 3. Private LTE / Fiber (Current Capacity)
- 14 4. Public LTE (Expanded Use Cases)
- 15 5. Private LTE / Fiber (Expanded Use Cases)

16 The BCA methodology first starts with establishing the life-cycle costs for the current DTE  
17 Electric telecommunication system. This is referred to as the current state scenario. This  
18 scenario serves as the baseline to evaluate the other alternatives both at the system level  
19 and substation / fiber routes level. This scenario assumes no additional devices are added  
20 to the system. The life-cycle cost evaluation includes the replacement of edge devices,  
21 carrier fees, obsolescence risk costs, and other maintenance costs. A unique component of  
22 estimating the life-cycle cost of this scenario is estimating when devices need to be  
23 replaced while also incorporating how many times those devices will need to be replaced  
24 over a 40-year time horizon, given the shorter life cycle of these devices. This approach  
25 utilized end-of-life curves and estimated ages for equipment to estimate these costs.

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1 Second, the BCA methodology estimated the life-cycle costs for the two alternatives being  
2 considered by DTE Electric, Public LTE and Private LTE / Fiber, assuming the current  
3 telecommunication capacity and no additional capabilities are needed (scenarios 2 and 3).  
4 In other words, this scenario assumes no new use cases and no new devices will be added  
5 to the telecommunications system, only replacement of existing devices. The purpose of  
6 this approach is to understand which alternative at the system level provides the lowest  
7 life-cycle costs if no new capabilities are needed. Since the BCA between these two  
8 scenarios is highly dependent on the number of connected devices, this serves as the “floor”  
9 in comparing the alternatives. For this evaluation, the BCA employs a least cost  
10 methodology. The Public LTE life-cycle cost evaluation includes many of the same cost  
11 drivers as the current state scenario described above. Key differentiators of this scenario to  
12 the current state are lower device replacement costs, avoided legacy O&M costs with the  
13 current state telecommunication system, and more exposure to obsolescence risk. The  
14 Private LTE / Fiber alternative has different cost drivers than the current state and Public  
15 LTE solutions. From a high-level perspective, the Private LTE / Fiber alternative has higher  
16 upfront costs to build out the telecommunication system infrastructure and buy spectrum  
17 with significantly lower costs once this investment is made.

18  
19 In the third step, the BCA methodology similarly estimated the life-cycle costs for the two  
20 alternatives being considered by DTE Electric, however, with expectations for additional  
21 deployment of devices and communication capacity, including latency (scenarios 4 & 5).  
22 One of the key drivers to move to an alternative telecommunication solution platform is to  
23 enable additional capabilities that the current state solution would be challenged to  
24 accommodate. The purpose of this step in the BCA methodology is to understand which  
25 scenario provides the lowest lifecycle costs in a future where more devices that need

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1 improved latency and bandwidth are added to the system. This is a likely future as  
2 advancements in technology for utility operations and maintenance continue to evolve and  
3 accelerate. DTE Electric provided approximately 4,600 new devices to be included. Most  
4 of these devices included additional capacitors and regulators to support power quality on  
5 the system with a few more net banks and vaults. The planning approach utilized the  
6 distribution automation analysis to estimate the new recloser counts to be included in the  
7 evaluation, approximately 4,500 new devices. I combined the benefit cost analysis of the  
8 Distribution Automation program with this life-cycle cost analysis for each of the expanded  
9 use case scenarios.

10  
11 **Q29. How did you leverage the Global Strategy BCA to understand the benefits of Local**  
12 **telecommunication strategies?**

13 A29. As part of the conceptual structure and design of the telecommunication alternatives, DTE  
14 Electric provided cost driver mapping to each substation. Utilizing this substation linkage,  
15 each of the cost drivers was mapped to specific substations for each scenario. Additionally,  
16 investments and costs were aggregated for the DTE Electric Distribution Automation  
17 program to each substation. With this mapping of the costs and benefits to each substation,  
18 the benefit cost evaluation was performed at the substation level for each scenario.

19  
20 **Benefit Cost Analysis Results**

21 **Q30. Can you please provide an overview of the PTMM Groundline pole inspection BCA**  
22 **results?**

23 A30. The DTE Electric sub-program was comprehensively evaluated across the entire DTE  
24 Electric system, 3,108 circuits. If this program were applied to the entire DTE Electric  
25 distribution system, the overall investment level would be approximately \$1.65 billion. The

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benefit-cost analysis (BCA) shows that approximately 86 percent of circuits have quantified benefits in excess of costs for customers. In other words, the BCR was greater than 1 for 2,703 circuits. From an investment level perspective, approximately \$1.61 billion, or 97.1 percent of the total investment level, has quantified benefits in excess of cost for an aggregate BCR of 1.71. The expected avoided CMI percentage for all beneficial projects averaged 11 percent, ranging from 9 percent to 14 percent.

**Q31. Can you please provide an overview of the PTMM Pole Top BCA results?**

A31. Similarly, this program was evaluated comprehensively across the entire DTE Electric system. If this program were applied to the entire DTE Electric distribution system, the overall investment level would be approximately \$709 million. The benefit-cost analysis (BCA) shows that approximately 82 percent of circuits have quantified benefits in excess of costs for customers. From an investment level perspective, \$691 million, or 97% of the total investment level, has quantified benefits in excess of cost for a BCR of 2.81. The expected avoided CMI percentage for all beneficial projects averaged 9 percent, ranging from 5 percent to 10 percent.

**Q32. Are there other benefits for the PTMM program not included in the quantified benefits cost analysis?**

A32. Yes, a key benefit stream not included in the quantified benefit cost analysis is mitigating safety risks. Pole failures expose the public to safety hazards. Additionally, there are benefits to DTE Electric crews in not having to replace failed equipment reactively. One of the failure types included in the quantitative evaluation was equipment failures during major gray sky events. In this scenario, crews replace failed pole infrastructure following major events. This can be in extreme cold or wet conditions with infrastructure

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1 replacements occurring at all hours of the day, including in the dark. This program would  
2 mitigate the number of failures during these types of events and reduce the safety risk  
3 exposure to DTE Electric crews. In light of safety considerations, inspection-based  
4 programs like PTMM are appropriate for the sole purpose of mitigating safety risks.

5  
6 **Q33. Can you please provide an overview of the Strategic Undergrounding results?**

7 A33. Two projects, Attica and Spruce, were evaluated for this DTE Electric program. For Attica,  
8 the BCA yielded benefit-cost ratios of 0.64 for PTMM, 0.54 for Overhead Rebuild, and  
9 1.51 for Underground Conversion. The undergrounding scope for this project involves  
10 converting the overhead primary to underground while keeping the overhead secondary as  
11 is. The estimated investment for this undergrounding is approximately \$2.1 million, with  
12 benefits of approximately \$3.2 million.

13  
14 For Spruce, the benefit-cost ratios are 0.73 for PTMM, 1.35 for Overhead Rebuild, and  
15 0.69 for Underground Conversion. The undergrounding scope for this project includes  
16 converting all overhead assets to underground. The estimated investment for this  
17 undergrounding is approximately \$11.6 million, with benefits of approximately \$8 million.

18  
19 **Q34. Can you provide an overview of the Distribution Automation results?**

20 A34. This DTE Electric program was evaluated comprehensively across the entire DTE Electric  
21 system, 2,721 circuits. Eight hundred and eighty-three of these circuits were not eligible  
22 for this program since they didn't meet the 400-customer count threshold. If this program  
23 were applied to the remaining 1,838 eligible circuits, the overall investment level would be  
24 approximately \$1.03 billion. The benefit-cost analysis (BCA) shows that approximately 64  
25 percent of eligible circuits have quantified benefits in excess of costs for customers. From

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1 an investment level perspective, \$830 million, or 80.6% of the total investment level, has  
2 quantified benefits in excess of cost for a BCR of 4.36. The expected avoided CMI  
3 percentage for all beneficial projects averaged 26 percent, ranging from 15 percent to 51  
4 percent.

5  
6 **Q35. Can you provide an overview of the Grid Automation Telecommunications scenario**  
7 **life-cycle cost results?**

8 A35. The life-cycle cost analysis shows that for the current capacity scenario, the scenario where  
9 no new capabilities for telecommunication are needed, the Private LTE / Fiber scenario has  
10 the lowest 40-year life-cycle cost of \$661.1 million, followed by the Public LTE scenario  
11 with \$686.0 million. The Private LTE / Fiber alternative has a lower life-cycle cost than  
12 the Public LTE alternative by approximately \$25 million. The current state scenario has a  
13 life-cycle cost of \$801.7 million, \$115.7 million over the Public LTE scenario. This is  
14 mainly driven by the higher unit replacement costs for devices. This demonstrates that even  
15 without considering new device deployment and additional use cases, continuing with the  
16 current system is not beneficial for customers and switching to a common  
17 telecommunication platform would provide lower life-cycle cost for customers. In  
18 summary, this is a call to action to establish a long-term preferred telecommunication  
19 system and for DTE Electric to start investing toward that solution.

20  
21 For the expanded use case scenarios which include new device additions, the life-cycle cost  
22 analysis shows the Private LTE / Fiber scenario has the lowest life-cycle cost, \$707.1  
23 million, compared to the Public LTE scenario with \$793.9 million. The Private LTE / Fiber  
24 scenario life-cycle cost is nearly \$87 million lower, or 11 percent lower, than the expanded  
25 use case Public LTE alternative.



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1   **Q36. Can you provide an overview of the Grid Automation Telecommunication benefit cost**  
2       **analysis?**

3   A36. The benefit cost analysis includes two main benefit streams. The first is avoided life-cycle  
4       costs of the current state scenario, approximately \$801.7 million. The second quantified  
5       benefit stream is the monetized avoided outages benefits from enabling distribution  
6       automation, approximately \$3,348 million. The current capacity scenarios only get the first  
7       current state-cycle cost benefits stream. Both the Public LTE and Private LTE / Fiber  
8       scenarios have benefits in excess of costs with BCRs of 1.17 and 1.21 respectively. For the  
9       expanded use case scenarios, the Public LTE and Private LTE / Fiber scenarios have  
10      benefits in excess of costs for customers with BCRs of 2.69 and 2.86, respectively. These  
11      results show that as more devices are needed across the system, the Private LTE / Fiber  
12      scenario will provide more benefits to customers.

13

14   **Q37. Are there other benefits for the DTE Electric Grid Automation Telecommunication**  
15       **program not included in the quantified benefits cost analysis?**

16   A37. Yes, several additional qualitative factors provide context on the preferred long-term  
17       system level telecommunication strategy for DTE Electric.

18

19       First, a Private LTE / Fiber network is expected to be more reliable than the Public LTE  
20       network. Recent outage events from public carriers demonstrates this concern. While these  
21       types of outages can be concerning, of more concern is capacity limitations during major  
22       events. During these types of events, distribution automation has the potential to  
23       dramatically reduce the number of outages customers experience. However, if the public  
24       networks are over capacity, there may be issues with communication between devices for  
25       automated switching schemes.

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1 The second qualitative factor is elevated cyber security risks for the Public LTE system.  
2 The Private LTE / Fiber network is more immune to these type of attacks since the public  
3 carriers are larger targets for cyber-attacks.

4  
5 The third factor to consider is regulatory cyber security risk. This is related to the second  
6 factor above but slightly different. The second factor is concerned with cyber-attacks  
7 within the DTE Electric service area impacting utility operations. This factor is more global  
8 where the cyber threat grows to such a level that regulations require more communication  
9 over private closed networks. In this scenario, DTE Electric may be required by regulation  
10 to move more of its telecommunication system to private networks over time. Therefore,  
11 any investments not in alignment with the Private LTE / Fiber alternative are at risk of  
12 being stranded and requiring additional, potentially duplicative, investment.

13  
14 A fourth factor to consider is the growth in device counts. With a Private LTE / Fiber  
15 network, DTE Electric would be able to more cost effectively add additional devices and  
16 use cases to the network. Currently the following additional use cases are in consideration:  
17 Gas meters in the electric territory, demand response devices, and mobile office  
18 connections. Further use cases for electrification and distributed energy resources (DERs)  
19 could more cost effectively be integrated into the DTE Electric electrical system with a  
20 Private LTE / Fiber alternative.

21  
22 The fifth factor to consider is the escalation in Public LTE carrier fees. The quantitative  
23 evaluation assumed the current fee levels would increase by approximately 2.5 percent a  
24 year. There is a real potential that with the demand growth in telecommunication needs  
25 across all public LTE users that fees are higher than 2.5 percent. Additionally, the

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1 evaluation did not factor in overage fees when DTE Electric use goes above contractual  
2 limits. The cost of the Public LTE alternative could be higher by \$92.7 million to \$105.8  
3 million depending on the number of incremental devices added to the system.

4  
5 **Q38. What do the results of the localized substation telecommunication benefit cost**  
6 **analysis show?**

7 A38. The results show that of the 602 DTE Electric substations included in the evaluation over  
8 70 percent of the substations have a BCR greater than 1 for both the Public LTE and Private  
9 LTE / Fiber alternatives for the expanded use case scenario. The Public LTE alternative  
10 has 20 more substations with quantified benefits in excess of costs than the Private LTE /  
11 Fiber alternative, 450 compared to 430. However, when excluding sunk costs from the  
12 evaluation for towers and spectrum, the Private LTE / Fiber scenario has 466 substations  
13 with benefits in excess of costs.

14  
15 While there are still a significant number of substations with quantified benefits that are  
16 lower than their costs, approximately 30 percent, additional context is needed to understand  
17 the level of investment for these substations. For all investment in all 602 substations,  
18 approximately 96 percent of this investment has benefits in excess of costs for customers.  
19 The 30 percent of investment accounts for less than 4 percent of all life-cycle costs for the  
20 telecommunication and distribution automation investment. Also, when factoring in the  
21 sunk costs, this percentage of investment decreases even further.

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1 **Q39. What do the results of the 8 localized fiber routes telecommunication benefit cost**  
2 **analysis show?**

3 A39. The results show that all eight fiber routes have benefits in excess of costs for customers.  
4 In comparing the Public LTE and Private LTE / Fiber routes alternative for the expanded  
5 use case scenario, the evaluation shows that 6 of the 8 routes have a higher benefit cost  
6 ratio for the Private LTE / Fiber alternative. When excluding sunk costs, 7 of the 8 routes  
7 show a higher BCR for the Private LTE / Fiber scenario. For the one route where the Public  
8 LTE shows quantified benefits higher than the Private LTE / Fiber alternative, the benefit  
9 cost ratios are very close, 1.00 compared to 0.93. In this scenario it is important to consider  
10 the qualitative factors discussed above, namely cyber security risk, regulatory cyber  
11 security obsolescence risk, and additional device counts. Given these other factors and the  
12 close benefit cost ratios, this fiber route investment is likely to provide customers the most  
13 benefit.

14

#### 15 **Summary and Conclusion**

16 **Q40. What conclusions can be drawn from the benefit cost analysis?**

17 A40. The following are the high-level conclusions of the benefit cost analyses for the DTE  
18 Electric distribution programs as evaluated within 1898 & Co.'s Integrated Resilience,  
19 Reliability, & Risk Investment Model and presented in this rate case.

- 20 • The resilience, reliability, and risk BCR value is a robust and reliable measure to  
21 help understand the justification for investment activities. This multi-factored and  
22 quantified benefit metric provides additional confidence that investments will  
23 provide benefits in excess of costs for customers. Additionally, the benefit cost  
24 analysis is comprehensive, consistent, customer centric, data driven, and practical.

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- 1           • The Pole and Pole Top Maintenance & Modernization program is beneficial for  
2           DTE Electric customers and provides a significant opportunity to improve  
3           reliability and manage safety risks on the system. The benefit cost analysis shows  
4           that over 97 percent of inspection investment on the system has quantified benefits  
5           in excess of costs for customers with average BCRs of 1.71 and 2.81 for the  
6           groundline and pole-top inspections projects respectively. The safety risk  
7           mitigation benefits provide justification for executing these programs on the  
8           remaining 3 percent of investment. Based on the rejection rate analysis, the benefit  
9           cost analysis shows \$1,657 million and \$709 million, in present value terms, of  
10          investment for the groundline and pole-top programs. Delaying or stretching this  
11          program over more years will be less beneficial for customers as the opportunity to  
12          replace deficient equipment is missed.
- 13          • The Strategic Undergrounding Pilot program projects, ATICA0302 and  
14          SPRUC9836, show a BCR of 1.51 and 0.69, respectively, for the OH to UG  
15          conversion scenario.
- 16          • The Distribution Automation program is a cost-effective investment solution to  
17          improve safety and reliability, and it provides significant benefits to customers. The  
18          benefit cost analysis shows that approximately 64 percent of eligible circuits have  
19          reliability benefits in excess of costs for customers. Positive BCR investment is  
20          approximately \$830 million with a BCR of 4.36. The positive BCR circuits are  
21          expected to decrease customer minutes interrupted by approximately 26 percent.  
22          Additionally, the investment in 4.8 kV reclosers to manage live-wire down risks is  
23          a cost-effective solution to manage this risk. It should be noted that the DTE  
24          Electric Grid Automation Telecommunication program is needed to fully capture  
25          the benefits of this program.

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- 1 • Private LTE / Fiber is the preferred system wide or global strategy for a
- 2 telecommunications solution for DTE Electric customers. In other words, the
- 3 Private LTE / Fiber alternative is the long-term “North Star” infrastructure platform
- 4 that yields the most benefits for customers. The benefit cost analysis also shows the
- 5 following:
- 6     ○ Telecommunication investments are fundamentally enabling investments in
- 7     that they don't produce benefits on their own but instead provide the
- 8     foundation for benefit realization for other investments like Distribution
- 9     Automation.
- 10    ○ For a range of communication capacity needs, the Private LTE / Fiber
- 11    alternative provides more benefits for customers than the Public LTE
- 12    alternative. For the expected use case expansions, the Private LTE / Fiber
- 13    alternative provides a BCR of 2.86 compared to 2.69 for the Public LTE
- 14    alternative.
- 15    ○ Additional qualitative factors demonstrate that the BCR values are more
- 16    likely to increase for the Private LTE / Fiber alternative and decrease for the
- 17    Public LTE alternative.
- 18    ○ Localized benefit cost analysis results also show that the Private LTE / Fiber
- 19    alternative is the most beneficial solution for customers. For the eight fiber
- 20    routes included in this case, all eight have benefits in excess of costs for
- 21    customers and 7 of the 8 have a higher BCR with the Private LTE / Fiber
- 22    alternative. For the one with a higher BCR for the Public LTE alternative,
- 23    the difference in BCR is minor and when factoring in the qualitative factors
- 24    the private fiber routes should be considered the preferred solution.

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- While the Private LTE / Fiber alternative is the preferred solution across most local areas on the system, there is opportunity for DTE Electric to perform local optimization to provide benefits to customers. This local optimization may include utilizing Public LTE.
- Many of the programs will benefit all DTE Electric customers. The nature of the PTMM, Distribution Automation, and Grid Automation Telecommunications programs is widespread across the entire DTE Electric system. The avoided reactive and investments costs are shared by all distribution customers. Additionally, distribution customers will experience fewer storm outages from both direct and indirect factors. Direct benefits are realized by those customers whose infrastructure is located directly downstream of the resiliency investment. Indirect benefits are realized by all distribution customers since storm restoration crews will be able to rebuild the system more quickly because less infrastructure will fail.
- **The investment benefits are conservative.** First, the DOE ICE Calculator is likely conservative for residential customers, as the underlying data pre-dates the significant advancements in societal use of electronic devices and technologies or trends toward work-from-home arrangements and the DOE ICE Calculator has not been updated to account for this societal shift. Second, in extrapolating the ICE Calculator for longer duration events, the modeling approach has conservatively not assumed any higher values. Third, the quantified benefit cost assessment has carefully included the full cost of implementing investments; however, the full level of benefits has not been captured. Specifically, the evaluation has not incorporated qualitative benefits associated with improved safety, mitigation of cyber risk, or service improvement in areas of lower performance where quantified benefits are

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1 not in excess of cost. Fourth, the telecommunication BCA was conservative in both  
2 the expected device count and the cost of the Private LTE / Fiber alternative.

3

4 **Q41. Does this conclude your direct testimony?**

5 A41. 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-21860

QUALIFICATIONS  
  
AND  
  
DIRECT TESTIMONY  
  
OF  
  
BRIAN L. HILL

**DTE ELECTRIC COMPANY**  
**QUALIFICATIONS AND DIRECT TESTIMONY OF BRIAN L. HILL**

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1    **Section 1 – Background & Qualifications**

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

3    A1.    My name is Brian L. Hill (he, his, him), and my business address is One Energy  
4           Plaza, Detroit, Michigan, 48226 and I am employed by DTE Electric Company  
5           (DTE Electric or Company).

6  
7    **Q2.    On whose behalf are you testifying?**

8    A2.    I am testifying on behalf of DTE Electric.  
9

10   **Q3.    What is your educational background?**

11   A3.    I graduated from Michigan State University Eli Broad College of Business. I  
12           graduated with a Bachelor of Arts Degree in Materials & Logistics Management  
13           with a focus on Operations Management. I received a Juris Doctorate (JD) Degree  
14           from the University of Detroit Mercy School of Law. I have also completed several  
15           Company-sponsored courses and attended various seminars to further my  
16           professional development, including receiving a Lean Six Sigma Certification.

17  
18   **Q4.    Please summarize your professional experience.**

19   A4.    I began my career in the automotive industry working for Johnson Controls, a  
20           world-wide Tier 1 OEM supplier. I worked there from 1994-2008 where I held  
21           several positions in materials, operations, and plant management. In my plant  
22           manager role, I was responsible for all aspects of the business including safety,  
23           operations, engineering, quality, materials, finance/accounting, continuous  
24           improvement, and human resources. The plant employed approximately 400  
25           people comprised of both salaried employees and UAW union members. My

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1 employment with DTE Energy began in October 2008 as the Logistics Manager in  
2 Energy Supply. Between January 2011 and November 2012, I was the Senior  
3 Supply Chain Manager at the Fermi 2 Nuclear Power Station where I held  
4 responsibility for warehousing, procurement, contracts, and work management.  
5 These activities were essential to supporting safe, reliable, and efficient plant  
6 operations, including refueling outages. Between December 2012 and March 2015,  
7 I was a Director in Corporate Services where I held increasing leadership  
8 responsibilities in the Center of Excellence, Supplier Performance Management,  
9 and Facilities Operations. In this last role, I was responsible for strategic planning,  
10 operational metric reporting, safety strategy, resource planning, financial  
11 forecasting, and continuous improvement. I was also responsible for both the long-  
12 term and daily operations of facilities management, including asset management.  
13 Between April 2015 and October 2016, I was the Director of Tree Trimming in the  
14 Distribution Operations organization of DTE Electric. In this role, I was  
15 responsible for leading the strategic development and implementation of the  
16 Enhanced Tree Trim Program (ETTP). In addition, I was responsible for Tree Trim  
17 Operations, which was comprised of both DTE Electric employees and tree trim  
18 contractors (comprising over 500 employees in 2016). In this role, I was  
19 responsible for safety, quality, productivity, customer satisfaction, storm and  
20 trouble restoration efforts, and improving relationships with municipalities. In  
21 November 2016, I started my role as the Director of Scheduling and Coordination  
22 in the Distribution Operations organization of DTE Electric. During this time, I  
23 was also responsible for the Project Management Office from November 2016 until  
24 June 2022 where I managed a large portfolio of projects and programs for  
25 Distribution Operations that included both planning and construction. In October

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1 2023, I was assigned the Director position for both Southwest Regional Customer  
2 Operations and Scheduling & Coordination.

3

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

6 A5. Yes. I am a Licensed Attorney in the State of Michigan and I am a Lean Six Sigma  
7 Black Belt.

8

9 **Q6. What are your current duties and responsibilities?**

10 A6. My responsibilities as Director Southwest Regional Customer Operations and  
11 Scheduling & Coordination include six primary areas: 1) Southwest Regional  
12 Customer Operations, 2) Overhead & Underground Scheduling, 3) Substations  
13 Planning & Scheduling, 4) Work Management, 5) Billing, Unitization, and  
14 Construction Inspections, and 6) Overhead and Underground Center of Excellence.  
15 These organizations are briefly described below:

16

17 Southwest Regional Customer Operations: Lead over 800 full-time and contract  
18 employees responsible for engineering, planning, maintaining, operating,  
19 constructing, and improving the electrical system to ensure the delivery of safe,  
20 reliable electric service. The Southwest region has three service centers located in  
21 Newport, Belleville, and Ann Arbor that serve approximately 605,000 DTE Electric  
22 customers.

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1 Overhead & Underground Scheduling: This organization schedules all planned  
2 work for both DTE Electric and contractor field crews on overhead and underground  
3 subtransmission and distribution assets.

4

5 Substations Planning & Scheduling: This organization plans and schedules all work  
6 for both DTE Electric and contractor field crews on substation assets. The team also  
7 includes field contractor oversight for substation construction and modifications.

8

9 Work Management: This organization leads systematic approaches to track and  
10 measure work as well as streamline both business processes and routine tasks. The  
11 team governs the Maximo Business Process that coordinates team collaboration and  
12 workflows across all levels of the organization.

13

14 Billing, Unitization, and Inspection: This team is responsible for contractor accounts  
15 payable and invoicing, unitization of capital investments, and conducting field  
16 quality inspections to validate construction is built to standards and specifications.

17

18 Overhead and Underground Center of Excellence: This team includes subject matter  
19 experts (SMEs) in the areas of electrical safety and construction. This team is  
20 responsible for procedures, training, and governance of all overhead and  
21 underground work, including the apprentice programs.

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

3   A7.    Yes. I sponsored testimony in Case Nos. U-21297 and U-21534. In addition, I  
4           supported witness testimony related to the Enhanced Tree Trimming Program in  
5           prior rate cases.

6

7   **Section 2 – Overview & Executive Summary**

8   **Q8.    What is the purpose of your testimony?**

9   A8.    My testimony supports, as reasonable and necessary, the historical capital  
10          expenditures and proposed capital expenditures related to base capital programs.  
11          Base capital, as introduced by Witness Bill Chiu, is a necessary and critical set of  
12          investments to address emergent events and specific customer needs. This includes  
13          emergent replacements, customer connections, relocations, as well as others.

14

15          My testimony also provides an explanation of the Company's purchase and use of  
16          Portable Generators to support the Company's vulnerable customers (included in  
17          Exhibit A-12, Schedule B5.4, page 10, line 31 under the Infrastructure Resilience  
18          and Hardening Pillar) and an update on Miss Dig (which is not a capital program or  
19          expenditure) reporting changes made since Case No. U-21297.

20

21   **Q9.    Can you please expand on what is included in Distribution Operations Base**  
22           **Capital Programs?**

23   A9.    Investments in base capital programs, as introduced by Witness Chiu, are  
24          summarized on Exhibit A-12, Schedule B5.4, pages 1 and 2, including Emergent  
25          Replacements on lines 2 through 7 and Customer Connections, Relocations &

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1 Other, on lines 8 through 16 (with additional details on page 3 for Emergent  
2 Replacements and pages 4 through 6 for Connections, Relocations & Other). Also  
3 included on Exhibit A-12, Schedule B5.4 for base capital programs is AFUDC on  
4 page 16 and plant activity starting on page 17. Base capital programs are further  
5 supported on Exhibit A-23, Schedule M4.

6

7 **Q10. Are you sponsoring any exhibits in this proceeding?**

8 A10. Yes. I am sponsoring the following exhibits:

| 9  | <u>Exhibit</u> | <u>Schedule</u> | <u>Description</u>                                  |
|----|----------------|-----------------|-----------------------------------------------------|
| 10 | A-12           | B5.4            | Projected Capital Expenditures – Distribution Plant |
| 11 |                |                 | (Pages 1-10 & 16-23)                                |
| 12 | A-13           | C5.6            | Projected Operation and Maintenance Expenses –      |
| 13 |                |                 | Distribution Expenses - Damage Prevention (Page 4)  |
| 14 | A-23           | M4              | Distribution Plant Capital Project Detail –         |
| 15 |                |                 | Base Capital                                        |
| 16 | A-12           | B5.4.9          | Calculation of Emergent Replacement Reduction       |
| 17 |                |                 | Based on Strategic Spend                            |
| 18 | A-12           | B5.4.10         | CIAC Rate Incrementals Calculation Walk             |

19

20 **Q11. Were these exhibits prepared by you or under your direction?**

21 A11. Yes, they were.

22

23 **Q12. How is the remainder of your testimony organized?**

24 A12. The remainder of my testimony consists of the following three parts:

25 Part I Emergent Replacements

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1 Part II Customer Connections, Relocations & Other

2 Part III Additional Items

3

4 **Part I: Emergent Replacements**

5 **Q13. Which Base Capital programs are included under Emergent Replacements?**

6 A13. The Emergent Replacements section of Base Capital Programs includes Storm,  
7 Non-Storm, and Substation Reactive programs. Expenditures in these programs  
8 are necessary for public safety and delivering reliable power to the Company's  
9 customers. Investments in these areas are included in Exhibit A-12, Schedule B5.4,  
10 page 3 and include an emergent replacement reduction based on strategic spend.

11

12 The expenditures for Storm, Non-Storm, and Substation Reactive activities consist  
13 of labor and material costs, the use of which are influenced by weather conditions.  
14 While the volume of labor and materials may vary due to storms, the unit costs for  
15 labor and materials have been upwardly trending due to inflation. The Company's  
16 constant dollar forecasting methodology, discussed further below and supported by  
17 Witness Lyons, accounts for these inflation fluctuations.

18

19 **Q14. Did the Company use a historical five-year average to forecast Emergent**  
20 **Replacement expenditures in the instant case?**

21 A14. Yes. The Company forecasted Emergent Replacement expenditures using a five-  
22 year average to forecast the bridge period and projected test year in the instant case;  
23 this averaging method smooths out year-to-year variation, including weather. The



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1 Commission has supported this methodology in previous rate cases, including the  
2 most recent U-21534 Order<sup>1</sup>.

3

4 **Q15. Did the Company apply constant dollar averaging to the historical five-year**  
5 **average in the instant case?**

6 A15. Yes. Constant dollar averaging of historical costs is a necessary step in developing  
7 cost forecasts because inflation over time reduces the purchasing power of goods  
8 and services. The five-year average on emergent replacements includes an  
9 adjustment for inflation.

10

11 The Company's forecast also accounts for expenditure reductions due to strategic  
12 investments, as discussed later in my testimony. This is presented in Exhibit A-12,  
13 Schedule B5.4, page 3.

14

15 Company Witness Lyons' testimony supports the Company's use of constant dollar  
16 averaging to develop its cost forecasts. Specifically, his testimony demonstrates  
17 that constant dollar averaging is consistent with economic principles, ensures cost  
18 forecasts adjust for inflationary trends, and is a recognized practice in developing  
19 cost forecasts.

---

<sup>1</sup> Case No. U-21534 Order, January 23, 2025, p. 74

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1   **Q16. What did the Commission order regarding using historical inflation to forecast**  
2       **the emergent capital in Case No. U-21534?**

3   A16. The Commission's order stated certain cost categories demonstrated variability  
4       without necessarily demonstrating a consistent upward trend in costs that would  
5       indicate inflation. The Commission's order states:

6                "[The Company's Exhibit] shows downward trends for emergent  
7                replacements (storm) in 2020 and 2022 (2 years out of 5), and for emergent  
8                replacements (substation reactive) in 2019, 2020, and 2022 (3 years out of  
9                5). The costs reflect variability but no consistent upward trend. The  
10              Commission finds that application of the inflation factors to a simple five-  
11              year average for 2023, 2024, and 2025 is appropriate, but the prior historical  
12              adjustment that the company uses in the instant case...is not."<sup>2</sup>

13

14       The Commission also applied this ruling to the other Base Capital expenditure  
15       categories of Connections and New Load, Relocations, Electric System Equipment,  
16       Normal Retirement Units Changeout (NRUC) and Improvement Blankets, and  
17       General Plant, Tools & Equipment.

18

19   **Q17. Does the Company agree with the Commission's concern that certain cost**  
20       **categories demonstrated cost variability without necessarily demonstrating a**  
21       **consistent upward trend in costs that would indicate inflation?**

22   A17. No, the Company does not agree. There is a consistent upward trend in material  
23       and labor costs that reflects inflation, supporting the Company's use of constant  
24       dollar averaging to develop its cost forecasts. Constant dollar averaging adjusts for

---

<sup>2</sup> Case No. U-21534 Order, January 23, 2025, pp. 73 - 74

Line  
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1 the impact of inflation on historical costs, providing for a more accurate forecast of  
2 future costs. The Company believes it is appropriate to use constant dollar  
3 averaging of historical costs when forecasting future costs. The Commission had  
4 approved this methodology in previous rate cases, specifically Case Nos. U-20162,  
5 U-20561, U-20836, and U-21297. The justification for using constant dollar  
6 averaging of historical costs in the instant case is supported by Witness Lyons.

7

8 **Q18. Does the increased frequency and intensity of extreme weather in the**  
9 **Company's service territory demonstrate cost variability in emergent**  
10 **replacements?**

11 A18. Yes, it does. Emergent replacement costs consist of labor and material, which are  
12 influenced by weather variability. The increased frequency and intensity of extreme  
13 weather in the Company's service territory has demonstrated year-over-year  
14 variability. Company Witness Chiu discusses the increasing frequency of extreme  
15 weather that affect the Company's electrical distribution system.

16

17 **Q19. Has the Company experienced consistent upward trends in labor and material**  
18 **costs?**

19 A19. Yes, the Company has experienced consistent upward trends in labor and material  
20 costs.

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1 **Q20. What upward trends in labor costs has the Company experienced that impacts**  
2 **forecasting?**

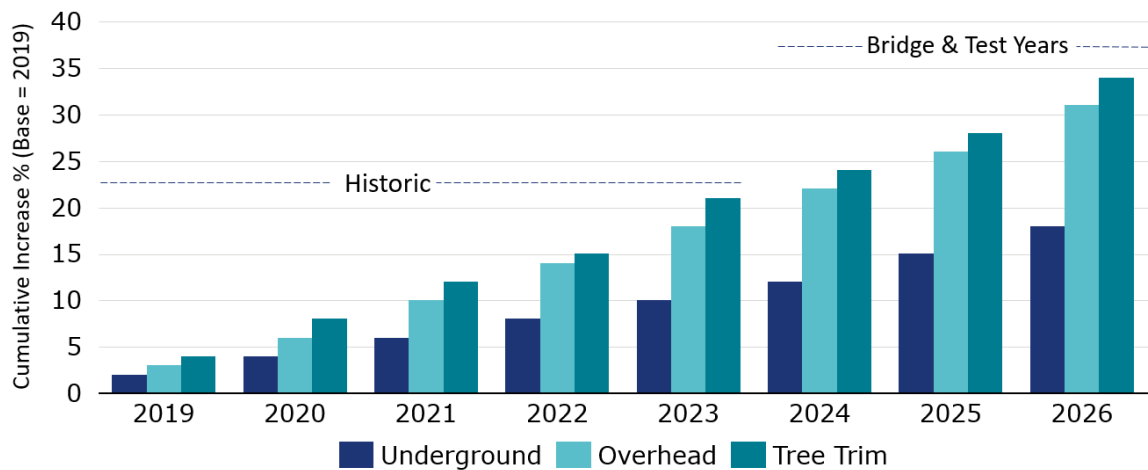
3 A20. The Company has experienced an upward trend in both DTE Electric labor and  
4 contract labor costs that would be missed if they were not included in the forecast.  
5 Company Witness Fix discusses DTE Electric labor escalations in his testimony.

6

7 Contractor labor rates are based on Collective Bargaining Agreements with local  
8 unions. Using 2019 as the base year, cumulative contract labor rate escalations for  
9 underground (UG), overhead (OH), and tree trim (TT) labor resources have been  
10 18%, 31% and 34%, respectively. The cumulative annual contract labor rate  
11 escalations for these three work categories are shown below in Figure 1.

12

13 **Figure 1 DO Contract Labor Cumulative Rate Escalations**



14

15 **Q21. What upward trend in material costs has the Company experienced that**  
16 **impact forecasting?**

17 A21. The Company has experienced substantial material increases on all major  
18 commodities (e.g., transformers, poles, conductors, etc.) over the five-year period

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1 of 2020 through 2024. For example, overhead transformer costs have increased by  
 2 318% and underground transformer costs have increased by 468%. Table 1 below  
 3 shows the average cost escalations for the 10 most commonly used materials in  
 4 emergent restorations (Transformer-Overhead, Transformer-Underground, Pole-  
 5 Wood, Underground Cable, Overhead Conductor, Overhead Crossarms, Fuse  
 6 Carriers, Insulators, Substation Transformers, and Substation Load Tap Changers)  
 7 from 2020 through 2024.

8 **Table 1. Frequently Used Emergent Replacement Material Cost Escalations**  
 9 **(%) 2020 through 2024**

| Material Category       | Stock Item Description                    | 2020 – 2024 % Change |
|-------------------------|-------------------------------------------|----------------------|
| Transformer-Overhead    | 50 kVA pole top transformer               | 318%                 |
| Transformer-Underground | 50 kVA padmount transformer               | 468%                 |
| Pole-Wood               | 45' Class 3 wood pole-Cedar               | 114%                 |
| Underground Cable       | 1000 kcmil AL UG EPR<br>(Price Per Foot)  | 68%                  |
| Overhead Conductor      | 636 OH Conductor<br>(Price Per Foot)      | 40%                  |
| Overhead Crossarms      | CROSSARM_with Center Bracket              | 36%                  |
| Fuse Carriers           | CUTOUT_FUSED,OP N,POLYMER,7.2-14.4KV,110K | 47%                  |
| Insulators              | INSULATOR_ELECT, CLAMP TOP,28KV,POLYMER   | 43%                  |
| Substation              | 50MVA Power Transformer                   | 54%                  |
| Substation              | Load Tap Changer                          | 21%                  |

Line  
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1   **Q22. Have you demonstrated that there is cost variability and an upward trend in**  
2       **material and labor costs that reflects inflation, supporting the Company’s use**  
3       **of constant dollar average to develop its cost forecasts?**

4   A22. Yes. Additionally, Witness Lyons supports why constant dollar averaging of  
5       historic costs is a necessary step in developing cost forecasts.

6   **Q23. Has the Company taken action to offset inflationary pressures?**

7   A23. Yes.

8  
9   **Q24. What did the Commission state regarding the offsetting effects of capital**  
10       **investments on inflationary pressures in Case No. U-21534?**

11   A24. The Commission stated that the Company has not produced a convincing case for  
12       “any continued need for inflationary adjustments to historical data in this cost  
13       category for emergent replacements in the future” and that it has sought this  
14       evidence through several rate cases<sup>3</sup>. The Company notes that the Commission’s  
15       statement stems from Case No. U-20836<sup>4</sup>.

16  
17   **Q25. How has the Company offset inflationary pressures in the emergent category?**

18   A25. The Company has offset inflationary expenditures in emergent investments based  
19       on strategic capital investments and the Tree Trim (TT) Surge program. This offset  
20       is shown in Exhibit A-12 Schedule B5.4, page 2, line 6 and is \$22.3 million for  
21       Calendar Year (CY) 2025 and \$23.2 million for CY 2026.

22

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<sup>3</sup> Case No. U-21534 Order, January 23, 2025, p. 74

<sup>4</sup> Case No. U-20836 Order, November 18, 2022, p. 63

Line  
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1 These avoided expenditures are calculated using the Company's Reliability Model  
2 as discussed by Company Witness Kryscynski. The Company developed a  
3 Reliability Model that forecasts the system reliability and investment impact based  
4 on outage events on the overhead distribution system as well as the impact of  
5 projects and programs which have the potential to reduce the impact of overhead  
6 outage events. The model accounts for reliability improvements from six large  
7 investment programs: Tree Trimming, 4.8kV Hardening, Pole Top Maintenance  
8 and Modernization, Customer Excellence, 4.8kV Conversion, and Automation. - or  
9 Refer to Witness Kryscynski's testimony for further discussion and details on the  
10 Reliability Model. This calculation is shown in Exhibit A-12, Schedule B5.4.9.  
11 Savings from the model were applied to Emergent Replacements in Exhibit A-12,  
12 Schedule B5.4, Page 2, line 6, columns f and g.

13

14 **Q26. Can you provide additional details regarding Emergent Capital categories for**  
15 **all storm, non-storm, and substation reactive expenditures?**

16 A26. Yes. Categories of storm, non-storm, and substation reactive, along with  
17 descriptions and examples, are provided in Tables 3 – 5 below. Expenditures in  
18 Storm and Non-Storm Emergent are incurred to support the field activities under  
19 eight work type categories: 1) Emergency Job, 2) Priority Customer, 3) Hazards, 4)  
20 Multiple Customer Outage, 5) Police/Fire, 6) Public Safety Concern, 7) Single  
21 Customer Outage, and 8) Single Customer Problem. Table 2 provides examples  
22 for each category.

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1

**Table 2. Storm and Non-Storm Work Category Descriptions**

| 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.                                                                                                                                                                                           |
| Priority 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                                                                                                                                                                                                                                                                                                          |

2

3 Emergent Replacements – Storm4 **Q27. Generally, what is included in Emergent Replacement – Storm?**

5 A27. This category includes expenditures for labor and material required to restore the  
6 distribution and subtransmission systems, which consists of overhead,  
7 underground, and substation infrastructure, from damage and outages occurring  
8 during weather events called “storms.” A storm is defined as greater than 760  
9 customer outage events (an outage event is when customers are left without power)  
10 impacting greater than 200 distinct circuits sustained for longer than one hour.  
11 These expenditures are necessary and prudent to restore customers’ power by



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1 replacing storm damaged equipment that caused customer outages and/or public  
2 hazards. A public hazard is defined as damaged equipment that has the potential to  
3 cause harm, such as a downed wire or a severely leaning pole.

4

5 I will provide additional information on what is generally included in storm labor  
6 and material expenditures below.

7

8 **Q28. What is generally included in storm labor expenditures?**

9 A28. When a storm is forecasted, the Company proactively activates its Incident  
10 Command System (ICS). ICS is a set of resources including personnel and  
11 processes that follow a standard set of protocols to streamline the preparation for  
12 and execution of storm-related outages. All labor managed under the ICS  
13 organizational structure is accounted for as storm expenditures. ICS labor that is  
14 typically completed during a declared storm period includes, but is not limited to,  
15 responding to reported wire downs and other hazards on the electric distribution  
16 system, customer outage restoration, tree trimming to facilitate customer  
17 restoration activities, and the operation of the electric system both in the field and  
18 at the Company's Electric System Operations Center (ESOC) to safely facilitate the  
19 storm activities.

20

21 **Q29. Can you expand on the labor that is included in the Incident Command System**  
22 **structure?**

23 A29. Yes. The ICS structure has five primary functional areas detailed below.  
24 Collectively, these functional areas support the safe and efficient restoration of  
25 power for customers.

Line  
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- 1 1. Central Incident Command Team: this is the central Emergency Preparedness  
2 and Response (EP&R) Organization that monitors and forecasts the impact of  
3 weather on the DTE Electric Electrical System. This organization also leads and  
4 governs all storm processes and activities. The Central Incident Command  
5 Team operates under the direction of the Incident Commander at DTE Energy  
6 Central Headquarters in Detroit.  
7
- 8 2. Electric System Operations Center (ESOC) & Electric Dispatch Team: this team  
9 monitors and is the operating authority of the DTE Electric system. The Dispatch  
10 Team uses the outage management system (OMS) to dispatch crews to wire  
11 downs, other hazards, and customer outages.  
12
- 13 3. Planning Team: this team is responsible for several functions during storm  
14 conditions including:
  - 15 a. Public Protection Teams: these are both Company and non-Company  
16 resources that are deployed to reported wire downs. These teams tape  
17 off areas with yellow caution tape and, in some cases, stand by wire  
18 downs until restoration crews arrive.
  - 19 b. Damage Assessment Teams: these are both Company and non-Company  
20 resources that are deployed to the field ahead of the restoration crews.  
21 These teams begin walking down circuits to identify and evaluate the  
22 extent of equipment damage (broken poles, spans of wire down, etc.).  
23 These teams quickly provide information and intelligence about storm  
24 damage on the electric system back the Central and Regional ICS Teams.  
25 The information is critical to assess the severity and location of damage

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1 on the electric system and determine the restoration materials needed.  
2 This information enables the Company to plan, schedule, and send the  
3 right type and number of crews and materials to work locations, which  
4 drives crew efficiency improvements.

5 c. Restoration Estimates Team: this team updates outage restoration times  
6 that inform DTE Electric customers of the estimated time their power  
7 will be restored. After a severe weather event, it can take several hours  
8 for the teams to assess the extent of the damage and develop a restoration  
9 plan due to variety of inputs needed to calculate restoration estimates.  
10 These inputs include, but are not limited to, the extent of the damage to  
11 the utility infrastructure (downed wires, broken poles, fallen trees, tree  
12 damage, etc.), crew resources (including in-state & out-of-state  
13 linemen), and the number of impacted customers. Once the extent of the  
14 damage is known, the restoration estimates can be updated accordingly.

15 d. School Restoration Lead Team: this team communicates and works with  
16 Regional ICS teams to inform school administrators of estimates for  
17 when power will be restored.

18 e. Community Teams and Vans: these teams are generally deployed to  
19 heavily damaged areas and communities. Teams will provide ice, water,  
20 and other types of support and provide updated storm restoration  
21 information to customers and. They will also coordinate with local city,  
22 county, and municipal leaders on emergency response centers where  
23 customers can go to for assistance.

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- 1           4. Operations Team: this team oversees the field resources that respond to wire  
2           downs, restore power, and return the electrical grid to normal operating  
3           configuration. Field resources include DTE Electric and contracted overhead  
4           and underground line workers, tree trimmers, substation operators, electrical  
5           maintenance journeymen, and electric field technicians. The Operations Chief  
6           leads and governs the following:
- 7               a. Regional Incident Command Teams: DTE Electric divides its service  
8               territory into four regions (Southeast, Southwest, Northeast, Northwest).  
9               Each region has an Incident Commander that oversees wire downs and  
10              restoration for their defined area. The Regional ICS Commander oversee  
11              the safety, deployment, supervision, and productivity of the field crews.  
12              If a Regional ICS Commander has areas of heavily damaged circuits,  
13              they will deploy a small incident command team to that area to  
14              coordinate and lead restoration efforts.
- 15
- 16           5. Logistics Team: this team provides all contractor field labor and materials. The  
17           labor is primarily local baseload contractor linemen who work every day on the  
18           Company's electrical system. During severe storm events, the Company will  
19           bring in additional contractors from outside our service area, including out-of-  
20           state workers that will travel to work on the DTE Electric grid. The Logistics  
21           Team will strategically locate storm yards near areas with heavy damage. Crews  
22           report to these yards and receive safety briefs, job packages, and materials under  
23           the oversight of DTE Electric field supervisors. The line workers park their  
24           trucks at these yards where they are fueled and re-stocked each evening after the  
25           crews are transported to hotels for food and lodging. Large storms can result in

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1 over 1,000 line workers and tree trimmers driving to the DTE Electric service  
2 territory to assist with restoration.

3

4 **Q30. Has the Company made efforts within ICS to expand the available wire down**  
5 **resource base as recommended in Case No. U-21305 Liberty Audit<sup>5</sup>?**

6 A30. Yes. As detailed in Q&A 29, two of the ICS Planning Team roles are Public  
7 Protection and Damage Assessment. The Company has expanded available wire  
8 down resources by merging some of the roles within the Public Protection and  
9 Damage Assessment Teams, namely the Secure First (SF) and Singles Damage  
10 Assessment (SDA) roles.

11

12 The Public Protection Team includes the SF role responsible for taping off hazards  
13 and guarding live wire downs until restoration crews arrive; SF works around the  
14 clock with day and night shifts. The Damage Assessment Team includes the SDA  
15 role responsible for assessing reported single outages and securing areas  
16 accordingly; SDA was primarily activated during the day shift with some night shift  
17 work as needed.

18

19 The Company's merger of the SF and SDA storm roles expands internal and external  
20 resources to respond to wire downs and then transitions them to damage assessment  
21 roles, as needed. The strategic consolidation of the SF and SDA roles bolsters the  
22 Company's customer service capabilities, reinforces public safety in securing

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<sup>5</sup> The DTE Electric Utility Distribution Audit Report ("Liberty Audit") was conducted by Liberty Consulting Group and filed in Case No. U-21305. The DTE Electric Audit Reports are available in filing ## U-21305-0012 and U-21305-0013 at <https://mi-psc.my.site.com/s/case/5008y000005KkdgAAC/in-the-matter-on-the-commissions-ownmotion-to-investigate-audit-and-review-the-methods-employed-by-dte-electric-company-and-consumers-energycompany-to-secure-good-electric-service-and-the-safety-of-the-public-pursuant-to-mcl-460555-and-mcl-460556>. Part II page 126 (accessed April 13, 2025)

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1 scenes, and streamlines the coordination of storm restoration efforts across our  
2 service territory during severe weather events. This consolidation effort will not  
3 only benefit storm restoration efforts, but any other instances where additional  
4 personnel are needed, such as in high impact days.

5

6 **Q31. Can you provide additional information on storm material expenditures?**

7 A31. Yes. Typical material expenditures during restoration of customer outages in a  
8 storm include transformers, poles, wire / conductors, crossarms, line hardware,  
9 capacitors, reclosers, switches, and cutouts, which are most often damaged by  
10 weather and tree impacts.

11

12 **Q32. What are the projected Emergent Replacement – Storm expenditures as**  
13 **shown on Exhibit A-12, Schedule B5.4?**

14 A32. The bridge period and projected test year storm expenditures for Distribution  
15 Operations for use in the instant case include 2024 actuals and forecasted 2025 and  
16 2026 amounts. The Company's 2024 Emergent Replacement – Storm actual  
17 expenditures were \$151.8 million (Exhibit A-12 Schedule B5.4, page 1, line 3,  
18 column (c)). This actual expenditure is lower than the five-year historic inflation  
19 adjusted average of \$259.5 million for the time-period 2019 through 2023 (Exhibit  
20 A-12 Schedule B5.4, page 3, line 5, column (g)). The 2024 storm expenditures  
21 were lower than the five-year average primarily because the Company and its  
22 customers experienced fewer declared storm events in 2024. In 2024, the Company  
23 declared four storm events, including two catastrophic storms, a CAT-1 storm in  
24 January and a CAT-2 storm in August.

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1 Storm expenditures for 2025 and 2026 are projected at \$276.4 million and \$284.9  
2 million, Exhibit A-12 Schedule B5.4, page 2, line 3, columns (f) and (g),  
3 respectively, based on a 5-year inflation adjusted historic average of the period  
4 2019-2023.

5

6 **Q33. How did the 2024 storm season compare to the 2023 storm season?**

7 A33. In 2024, the Company experienced four storm events. Two of the four storms  
8 (50%) were declared catastrophic (CAT). This included one level 1 catastrophic  
9 (CAT-1) storm and one level 2 catastrophic (CAT-2) storm.

10

11 In 2023, the Company experienced seven storm events. Five of the seven (71%)  
12 were declared CAT in nature and amongst the most damaging in Company history.  
13 This included two CAT-1 storms and three CAT-2 storms.

14

15 A CAT-1 storm is defined as 110,000 customers or more without power in a 24-  
16 hour period (5% of total customers affected). A CAT-2 storm is defined as 220,000  
17 customers or more without power in a 24-hour period (10% of total customers  
18 affected).

19

20 **Q34. Are there any investments planned by DTE Electric Information Technology**  
21 **(IT) that support the Company's storm processes?**

22 A34. Yes, there are four DTE Electric IT investments that support the Company's storm  
23 processes. These investments are Storm Resiliency, the Storm Data Lakehouse, the  
24 Storm Simulation Lab, and the Storm Cloud. All associated investments and

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1 benefits for these projects are sponsored by Company Witness Ambrose and can be  
2 found in Exhibit A-12 Schedule B5.7.4 and B5.7.7.

3

4 **Emergent Replacement – Non-Storm**

5 **Q35. Generally, what is included in Emergent Replacement – Non-Storm?**

6 A35. This category includes capital replacements required to restore power to the  
7 overhead and underground distribution systems and subtransmission electrical  
8 system and/or return to normal operating configuration during non-storm  
9 conditions. Non-storm conditions are defined as fewer than 760 customer outage  
10 events for the entire system. The “non-storm” description does not imply that these  
11 events are not caused by storms, high winds, or other weather-related events. It  
12 simply means that the customer outage events were lower than the “storm”  
13 threshold to be declared within a twenty-four-hour timeframe.

14

15 Non-Storm includes overhead and underground infrastructure work on the  
16 distribution and subtransmission systems during non-storm conditions although  
17 does not include planned strategic replacements. This category also includes  
18 equipment that fails for other reasons, not related to weather. Not all equipment  
19 failures lead to outages. However, damaged and failed equipment is considered  
20 emergent and the need to replace this equipment is reasonable and prudent because  
21 it poses the risk of power outages and hazards. Table 3 provides the four high-level  
22 non-storm categories, brief descriptions, and illustrative examples.



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1

**Table 3. Emergent – Non-Storm Description and Examples**

| Category                | Description                                                                                                                                                                                                                                                                                                                         | Examples                                                                                                                                                                                                                                                                                                                        |
|-------------------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| 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                                                                                        | <ul style="list-style-type: none"> <li>Vehicle (e.g. garbage truck, hauler, etc.) contacted a communications line, ripped down 5 spans of primary wire, and broke 4 poles and cross arms</li> <li>Crew cleared the hazards, restored most customers, replaced wires and poles, and then restored remaining customers</li> </ul> |
| 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 performed 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 | <ul style="list-style-type: none"> <li>Broken pole reported due to vehicle accident; crew temporarily fixed pole to remove hazard</li> <li>Pole was replaced the following month; this follow-up work was classified as “Non-Storm Reactive”</li> </ul>                                                                         |
| Non-Storm Corrective    | Replacements of equipment that are required to restore system to original configuration and involve coordination from the System Operations Center (SOC)                                                                                                                                                                            | <ul style="list-style-type: none"> <li>Failed underground cable caused an outage that a crew restored, but left system in abnormal condition</li> <li>Planned outage took place the following week to replace the damaged cable; this work was categorized as “Non-Storm Corrective”</li> </ul>                                 |
| Non-Storm Environmental | The disposal of environmentally hazardous materials from the Company’s retirement units/assets that are replaced outside of a declared Storm                                                                                                                                                                                        | <ul style="list-style-type: none"> <li>Car hit pad mounted transformer, damaging it and causing an oil leak</li> <li>Crew removed transformer and replaced it</li> <li>Environmental crew cleaned up oil</li> </ul>                                                                                                             |

2

3 **Q36. What are the projected Emergent Replacement – Non-Storm expenditures as**  
4 **shown on Exhibit A-12, Schedule B5.4?**

5 A36. The bridge period and projected test year non-storm expenditures for Distribution  
6 Operations for use in the instant case include 2024 actual and projected 2025 and  
7 2026 amounts. The Company’s 2024 Emergent Replacement – Non-Storm actual  
8 expenditures were \$272.4 million (Exhibit A-12 Schedule B5.4, page 1, line 4,  
9 column (c)). This actual expenditure is greater than the five-year historic inflation  
10 adjusted average of \$219.1 million for the time-period 2019 through 2023, Exhibit  
11 A-12 Schedule B5.4, page 3, line 12, column g. The drivers include supply chain  
12 disruptions, noteworthy upward trends in material costs as shown in Table 1,

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1 increasing frequency and severity of weather, greater emphasis on replacing aged  
2 and outdated equipment rather than repairing, a shift to higher specification  
3 materials and components (e.g., fiberglass crossarms rather than wooden), an  
4 increase in significant events that require more field crew resources to remediate, a  
5 storm preparation strategy to call in crews earlier in anticipation of storm events,  
6 and an increase use of contract and out-of-state field crews to be able to more  
7 quickly respond to storm events and eliminate follow-up work backlogs  
8 immediately after storms. The drivers behind the increase in non-storm emergent  
9 expenditures were also discussed in detail in Case No. U-21297<sup>6</sup>.

10  
11 Non-storm emergent expenditures for 2025 and 2026 are forecasted at \$233.4  
12 million and \$254.2 million, respectively (Exhibit A-12 Schedule B5.4, page 2, line  
13 4, columns f and g), based on a five-year inflation adjusted historic average of the  
14 period 2019-2023.

15  
16 **Q37. Would it be reasonable or prudent to defer Emergent Replacement – Storm &**  
17 **Non-Storm work?**

18 A37. No. This work is reasonable and prudent because it is work that the Company must  
19 do to meet its public service obligation and ensures that the electrical system is safe  
20 and reliable by restoring power and addressing hazards. Deferring this work would  
21 leave customers without power, reduces grid resiliency, poses system risk of  
22 additional equipment damage resulting in further customer outages, and leaves  
23 critical equipment in abnormal conditions. A learning from prior storms was that  
24 faster response to address abnormal circuits and equipment, as much as reasonably

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<sup>6</sup> T5 2745-2750

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1 possible, before the next weather pattern impacts the Company's service territory  
2 reduces and mitigates the risk for larger customer outages.

3

4 **Q38. Are there additional categories in Non-Storm Emergent Replacements in the**  
5 **instant case?**

6 A38. Yes. The Company is forecasting additional Corrective Maintenance replacements,  
7 as shown on Exhibit A-12, Schedule B5.4, page 3 line 17, which are sponsored by  
8 Witness Robinson.

9

10 **Emergent Replacement - Substation Reactive**

11 **Q39. Generally, what does Emergent Replacement – Substation Reactive include?**

12 A39. This category includes investments required to perform emergency replacements  
13 for substation equipment. A substation typically supports several distribution  
14 circuits, and an outage at a substation caused by equipment failure can impact  
15 thousands of customers. The Company makes these emergent investments to  
16 replace broken equipment that either led to customer outages, creates risk of  
17 customer outages, or impacts the operability of the electrical system. Table 4  
18 provides the high-level substation reactive categories, a brief description, and an  
19 example.

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1

**Table 4. Emergent – Substation Reactive Descriptions and Examples**

| Category                                          | Description                                                                                                         | Actual Examples                                                                                                                                                                                                                                  |
|---------------------------------------------------|---------------------------------------------------------------------------------------------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Substation Reactive- Major Equipment              | Replacement of the Company's substation equipment classified as major equipment                                     | <b>Twelve Mile Substation</b> <ul style="list-style-type: none"> <li>• Fire led to catastrophic failure and complete loss of substation</li> <li>• Company deployed portable equipment including a substation and multiple generators</li> </ul> |
| Substation Reactive – Minor Equipment             | Replacement of the Company's substation equipment classified as minor equipment                                     | <b>UNVIL Substation</b> <ul style="list-style-type: none"> <li>• 40kV insulator broke free</li> <li>• Replaced three 40kV insulators</li> </ul>                                                                                                  |
| Substation Reactive – Transformers and Regulators | Replacement of substation transformers and regulators                                                               | <b>Middlebelt Transformer 2</b> <ul style="list-style-type: none"> <li>• 40-year old transformer failed internally causing outages</li> <li>• Load switched to another transformer for two days until change of transformer complete</li> </ul>  |
| Substation Reactive – Non-Electrical Equipment    | Replacement of substation retirement units/assets not directly related to generation or transmission of electricity | <ul style="list-style-type: none"> <li>• Control house HVAC heating to remove condensation which can erode equipment</li> <li>• Fence/gate repairs which are mandated by NERC</li> </ul>                                                         |

2

3 **Q40. What are the projected Substation Reactive expenditures as shown on Exhibit**  
4 **A-12, Schedule B5.4?**

5 A40. The bridge period and projected test year expenditures for Distribution Operations  
6 for use in the instant case include 2024 actual and projected 2025 and 2026  
7 amounts. The Company's 2024 Substation Reactive actual expenditures were \$47.8  
8 million (Exhibit A-12 Schedule B5.4, page 2, line 5, column (e)). This is higher  
9 than the five-year historic inflation adjusted average of \$45.6 million for the time-  
10 period 2019 through 2023 (Exhibit A-12 Schedule B5.4, page 3, line 20, column  
11 (g)).

12

13 Substation Reactive expenditures for 2025 and 2026 are forecasted at \$56.6 million  
14 and \$59.9 million, respectively (Exhibit A-12 Schedule B5.4, page 2, line 5,

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No.

1 columns (f) and (g)), respectively, based on a five-year inflation adjusted historic  
2 average of the period 2019-2023.

3

4 **Q41. Why are non-electrical substation equipment failures classified under**  
5 **Substation Reactive expenditures on Exhibit A-12, Schedule B5.4, page 3 line**  
6 **25 (Substation Facility Repair)?**

7 A41. Non-electrical substation equipment is classified under Substation Reactive  
8 because substation assets, equipment, and facilities are critical for the safety,  
9 reliability, and security of the distribution grid. For example, substation fencing  
10 prevents the public from entering energized high voltage areas, protects critical  
11 equipment, and is part of grid security plan. When fencing and other physical  
12 security type devices fail, they need to be replaced immediately to ensure public  
13 safety and protect the security of the grid. Other equipment, like HVAC systems,  
14 control temperature and condensation in the substation; if this equipment fails, it  
15 must be immediately replaced to ensure that the substation operates as designed.  
16 Another example of non-electrical substation equipment is substation building  
17 infrastructure. The infrastructure houses equipment that fails and must be replaced  
18 (e.g., roof, doors, sidewalks). These activities are truly reactive in nature and  
19 require the Company to take immediate, prudent action to protect the safety,  
20 reliability, and security of the electrical system.

Line  
No.

1   **Q42. Can you describe the Projected 2025 Substation Facility Repair capital**  
2       **expenditure shown on Exhibit A-12, Schedule B5.4, page 3, line 25, column**  
3       **(h)?**

4   A42. Yes. The Company projects to spend \$8 million in 2025 on three substations in  
5       need of facility repairs. The Troy substation experienced a structural failure of a  
6       side wall during a 2024 wind weather event. The Chestnut substation side wall is  
7       also in need of replacement. Work scope includes engineering, permitting, and  
8       construction in 2025. In addition, the Imlay substation site needs replacement of  
9       steel structures and foundations due to steel erosion and loss of structural integrity  
10      to several connecting plates and support brackets. These facility repairs will address  
11      the structural concerns at each of these substations.

12

13   **Q43. Would it be reasonable or prudent to defer Emergent Replacement –**  
14       **Substation Reactive investments?**

15   A43. No. This work is to replace critical electrical grid equipment that has failed.  
16       Substation equipment tends to be less impacted by storms and other weather events,  
17       however, when substation equipment fails, in many cases, it leaves thousands of  
18       customers without power for what can be extended periods of time. The failed  
19       equipment significantly reduces distribution capacity and redundancy that is  
20       necessary to serve customers in the event of additional system failures and  
21       increased seasonal loads. Both these conditions increase the risk of additional  
22       customer outages. Substation capacity and redundancy are critical and required  
23       because these types of failures generally result in repairs that are very lengthy in  
24       time (weeks or months) which could result in extended customer outages if not  
25       addressed when the failure occurs.

Line  
No.

1 **Q44. Does the Company track and report Substation Reactive imminent failure**  
2 **work?**

3 A44. Yes. The Company tracks the expenditures related to imminent failures. The  
4 Company first began collecting Substation Reactive expenditures associated with  
5 imminent failures in January 2023. Imminent Failure Substation Reactive  
6 categories for 2024 are shown in Table 5 below.

7

8 **Table 5. Substation Reactive – Imminent Failure Detail<sup>7</sup>**

| Substation Reactive                        | 2024<br>(\$ thousands) |
|--------------------------------------------|------------------------|
| Imminent Failure – Major Equipment         | \$1,437.0              |
| Imminent Failure – Minor Equipment         | \$652.6                |
| Imminent Failure – Minor System/Circuits   | \$2,843.3              |
| Imminent Failure – Transformers/Regulators | \$382.3                |
| Failures – Major Equipment                 | \$10,194.0             |
| Failures – Minor Equipment                 | \$18,022.0             |
| Failures – Minor System/Circuits           | \$3,115.7              |
| Failures – Transformers/Regulators         | \$6,480.2              |
| Failures – Non-Electrical                  | \$4,699.8              |
| <b>Total Substation Reactive</b>           | <b>\$47,826.9</b>      |

<sup>7</sup> Values in this table are 2024 calendar year actuals (January through December). Exhibit A-12, Schedule B5.4, p. 2, line 5, column (e) shows 2024 actuals that is \$11,570 less than the total shown in Table 5 to account for a credit to a substation reactive project.

Line  
No.

1   **Q45. Are there additional categories in Substation Reactive replacements in the**  
2       **instant case?**

3   A45. Yes. The Company is forecasting additional Corrective Maintenance replacements,  
4       as shown on Exhibit A-12, Schedule B5.4, page 3 line 26, which are sponsored by  
5       Witness Robinson.

6

7   **Part II: Customer Connections, Relocations & Other Capital Investments**

8   **Q46. Can you please describe the Company's Customer Connections, Relocations**  
9       **& Other Capital Investments?**

10   A46. The Customer Connections, Relocations, and Other Investments category is broken  
11       down into six major subcategories: 1) Customer Connections and New Load; 2)  
12       Relocations; 3) Electric System Equipment; 4) Normal Retirement Unit Change-  
13       out (NRUC) and Improvement Blankets; 5) General Plant, Tools & Equipment and  
14       Miscellaneous; and 6) Public Lighting Department Project. These six subcategories  
15       are discussed in more detail below.

16

17   **Q47. Did the Company use a historical three-year average to forecast Customer**  
18       **Connections, Relocations, & Other Capital expenditures in the instant case?**

19   A47. Yes. The Company used a three-year average to forecast the bridge period and  
20       projected test year in the instant case. This averaging method smooths out year-to-  
21       year variation while accounting for customer-related trends. The Commission has  
22       supported this methodology in previous rate cases, including the most recent U-  
23       21534 Order<sup>8</sup>.

24

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<sup>8</sup> Case No. U-21534 Order, January 23, 2025, p. 79



Line  
No.

1   **Q48. Did the Company apply constant dollar averaging to the historical three-year**  
2       **average in the instant case?**

3   A48. Yes. Constant dollar averaging of historical costs is a necessary step in developing  
4       cost forecasts because inflation over time reduces the purchasing power of goods  
5       and services. The Company normalized Customer Connections, Relocations, &  
6       Other Capital expenditures based on the three-year average using a methodology  
7       that is consistent with Emergent Replacements expenditures as discussed in Part I  
8       of my testimony. This approach is supported by Witness Lyons. The three-year  
9       average includes an adjustment for inflation and is presented in Exhibit A-12,  
10      Schedule B5.4, pages 4 – 6.

11

12      Company Witness Lyons' testimony supports the Company's use of constant dollar  
13      averaging to develop its cost forecasts. Specifically, his testimony demonstrates that  
14      constant dollar averaging is consistent with economic principles, ensures cost  
15      forecasts adjust for inflationary trends, and is a recognized practice in developing  
16      cost forecasts.

17

18      There are two exceptions in this category of expenditures that do not use a three-  
19      year inflation adjusted average because they are unique, discrete projects; these  
20      projects are the I-375 relocation and Incremental Infrastructure for electric vehicle  
21      (EV) integration to the grid.

Line  
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**Q49. What capital expenditures are included in the Customer Connections and New Load subcategory as shown on Exhibit A-12, Schedule B5.4, page 4?**

A49. 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 subcategories 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

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1 system. New Business projects are typically requested by customers and can also  
2 carry a CIAC component.

3  
4 Incremental Infrastructure for EV is incremental capital for construction of EV  
5 charging infrastructure and is a subset of the Company's Transportation  
6 Electrification Plan (TEP) discussed further in my testimony.

7

8 **Q50. What are the Incremental Infrastructure for EV capital investments in Exhibit**  
9 **A-12 Schedule B5.4 on page 4, line 32 within Customer Connections and New**  
10 **Load?**

11 A50. In Case No. U-20836, the MPSC requested DTE Electric to "prepare and submit in  
12 its next rate case, a full scale, well-developed, permanent Charging Forward  
13 proposal that includes a BCA [benefit cost analysis]."

14

15 In response, the Company has developed a comprehensive Transportation  
16 Electrification Plan with the goal to power and enable a cleaner energy future for its  
17 customers through transportation electrification. The Transportation Electrification  
18 Plan is supported and discussed by Company Witness Foley.

19

20 Incremental Infrastructure for EV consists of capital investments of \$9.2 million in  
21 2025 and \$18.6 million in 2026 needed to build out EV charging infrastructure,  
22 which is a subset of the DTE Electric 2023 Transportation Electrification Plan. This  
23 capital investment is supported by Company Witness Foley<sup>9</sup>.

24

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<sup>9</sup> Refer to Witness Foley's Q&A 18

Line  
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1   **Q51. What capital expenditures fall into the Relocation subcategory as shown on**  
2       **Exhibit A-12, Schedule B5.4, page 5?**

3   A51. Relocation projects are requests to relocate electric services from residential,  
4       commercial, and industrial customers, cities, municipalities, or other governmental  
5       entities, for example, the Michigan Department of Transportation (MDOT). These  
6       are requests to relocate existing Company equipment and facilities. These requests  
7       are typically related to construction or the modification of roadways, bridges, water  
8       mains, public sanitation, alleys, or other customer activities.

9  
10       The Company equipment being relocated could include overhead lines and poles,  
11       underground lines and transformers, and substation equipment. With the increases  
12       in federal funding levels for investments in replacing and building infrastructure, it  
13       is expected that these types of projects will become more frequent.

14  
15       These investments enable economic growth, meet customer needs, are required by  
16       regulation, or in some cases are constructed at the request or mandate of  
17       governmental entities. Like Customer Connections and New Business, some  
18       projects in this category are partially funded by the requesting customer or entity  
19       and therefore can carry a CIAC component.

20

21   **Q52. What is the I-375 Relocations project under Major Infrastructure Relocation**  
22       **Project in this instant case?**

23   A52. The Company was notified by MDOT that it will need to relocate distribution  
24       infrastructure located in the I-375 below-grade freeway corridor, which will be  
25       replaced with a grade-level boulevard. The Company began this work in 2023. The

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1 Company spent \$6.3 million 2023 and \$6.3 in 2024 (Exhibit A-12, Schedule B5.4,  
2 page 5, line 42, columns e and g) to relocate electric infrastructure ahead of the  
3 actual road construction, and consistent with MDOT requirements. The Company  
4 projects an incremental expenditure on this project of \$30.0 million (Exhibit A-12,  
5 Schedule B5.4, page 5 line 42, columns h and i) spanning 2025 and 2026.

6

7 **Q53. Are there additional forecast updates to the Customer Connections,**  
8 **Relocations & Other capital expenditures that you would like to discuss?**

9 A53. Yes, the projected expenditures have been updated stemming from the  
10 Commission's order in Case No. U-21297.<sup>10</sup> The Customer Connections,  
11 Relocations, & Other capital expenditures forecast for 2025 and 2026 have been  
12 updated to reflect the implementation of new line extension CIAC. I discuss the  
13 implementation of the new rates below.

14

15 **Q54. Did the Company comply with the Commission's Order in Case No. U-21297**  
16 **regarding line extensions?**

17 A54. Yes. Consistent with the Order in U-21297, the Company reviewed Section 6 of  
18 the Rate Book with respect to customer CIAC costs and proposed updated rates in  
19 Case No. U-21534. The updated rates represent current cost per foot or cost per  
20 kVA developed using compatible unit estimates for associated labor and material  
21 costs. Refundable costs capture the full cost of construction and non-refundable  
22 costs represent cost differentials between overhead and underground construction.

23

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<sup>10</sup> Case No. U-21297 Order, December 1, 2023, p. 315

Line  
No.

1 **Q55. What was the outcome of the Company's proposed Rate Book updates on**  
2 **CIAC in Case No. U-21534?**

3 A55. The updated CIAC rates proposed in Case No. U-21534 were undisputed and  
4 authorized for implementation by the Commission as reflected in Attachment B  
5 (tariff sheets) in the Order.<sup>11</sup>  
6

7 **Q56. How do the updated CIAC rates authorized in Case No. U-21534 affect the**  
8 **Company's projected Connections, Relocations, and Other expenditures?**

9 A56. As previously described, Customer Connections, New Business, and Relocation  
10 projects can carry a CIAC component. The Company is utilizing a three-year  
11 constant dollar average of historic costs to forecast expenditures for 2025 and 2026  
12 in these categories. Therefore, it is necessary to recalculate the historical three-year  
13 average using the updated CIAC rates. This recalculation of historical CIAC  
14 transactions with the updated rates results in a \$25.1 million increase to the  
15 historical three-year average as shown in the CIAC Rate Incrementals Calculation  
16 Walk (Exhibit A-12, Schedule B5.4.10, line 22, column (f)). This adjustment to the  
17 constant dollar average results in a total reduction of \$43.2 million in projected base  
18 capital expenditures; I further detail this calculation below.  
19

20 **Q57. How was the incremental impact on the historical three-year average**  
21 **calculated due to the updated rates?**

22 A57. The Company analyzed all CIAC transactions over the historical three-year period  
23 and categorized them into three distinct groups: (1) No Rate Change, (2) Non-  
24 Refundable, and (3) Refundable. The No Rate Change category included any

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<sup>11</sup> Case No. U-21534 Order, January 23, 2025, p. 464

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1 transactions unaffected by the updated rates. The Non-Refundable category  
2 included any transactions for non-refundable CIAC elements that had a rate update  
3 in Case No. U-21534. The Refundable category included any transactions for  
4 refundable CIAC elements that had a rate update in Case No. U-21534. This level  
5 of transaction detail is available for the Customer Connections subcategory of base  
6 capital, which comprises nearly 70% of all CIAC transactions.

7

8 **Q58. What is the impact of the updated CIAC rates on the Customer Connections**  
9 **historical three-year average?**

10 A58. By categorizing the Customer Connections CIAC actuals for 2021 – 2023 into the  
11 previously mentioned groups and recalculating the Non-Refundable and  
12 Refundable transactions with the updated rates, the total incremental impact due to  
13 the updated rates on the historical three-year average is \$17.2 million (Exhibit A-  
14 12, Schedule B5.4.10, line 10, column (f)). The degree of change to the Customer  
15 Connections CIAC historical three-year average was 1.99x (Exhibit A-12,  
16 Schedule B5.4.10, line 13, column (f)).

17

18 **Q59. What is the impact of the updated CIAC rates on the New Business projects**  
19 **historical three-year average?**

20 A59. The Company applied the degree of change to the Customer Connections CIAC  
21 historical three -year average of 1.99x to the New Business CIAC actuals for 2021  
22 – 2023. This resulted in a total incremental impact of \$6.9 million on the New  
23 Business projects historical three-year average due to the updated rates (Exhibit A-  
24 12, Schedule B5.4.10, line 17, column (f)).

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No.

1 **Q60. What is the impact of the updated CIAC rates on the Relocations historical**  
2 **three-year average?**

3 A60. The Company applied the degree of change to the Customer Connections CIAC  
4 historical three-year average of 1.99x to the Relocations CIAC actuals for 2021 –  
5 2023. This resulted in a total incremental impact of \$1.0 million on the Relocations  
6 historical three-year average due to the updated rates (Exhibit A-12, Schedule  
7 B5.4.10, line 21, column (f)).

8

9 **Q61. What is the total impact of the updated CIAC rates on the Company's**  
10 **projected 2025 and 2026 Connections, Relocations, and Other capital**  
11 **expenditures?**

12 A61. The Company normalized the total incremental impact on the historical three-year  
13 average for Customer Connections, New Business, and Relocations by adjusting  
14 for inflation to forecast future CIAC. The projected base capital reductions due to  
15 the CIAC updated rate incrementals are \$14.1 million for 2025 and \$29.1 million  
16 for 2026<sup>12</sup>. This results in a total reduction of \$43.2 million in projected base capital  
17 expenditure due to the updated CIAC rates.

18

19 **Q62. What capital expenditures fall into the Electric System Equipment**  
20 **subcategory as shown on Exhibit A-12, Schedule B5.4, page 5?**

21 A62. The Company maintains an inventory of critical spare equipment to support  
22 emergent replacements and planned projects. This allows equipment repairs and  
23 replacements to proceed expeditiously, without waiting for parts delivery from  
24 vendors. Equipment purchased under this subcategory includes substation

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<sup>12</sup> 2025: Exhibit A-12, Schedule B5.4, p. 4, lines 17 and 30, column (h), and p. 5, line 54, column (h).  
2026: Exhibit A-12, Schedule B5.4, p. 4, lines 17 and 30, column (i), and p. 5, line 54, column (i).



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1 transformers, distribution transformers, regulators, and meters. This equipment  
2 often has long lead times, which in many cases have been increasing due to global  
3 supply chain and raw material issues. To ensure the Company can provide electrical  
4 service when critical equipment fails or to connect new customers, the Company  
5 plans and maintains necessary inventory levels of critical electrical system  
6 equipment.

7

8 **Q63. What capital expenditures fall into the NRUC and Improvement Blankets**  
9 **subcategory as shown on Exhibit A-12, Schedule B5.4, page 6?**

10 A63. The expenditures that fall into this subcategory include: 1) System Improvements,  
11 2) Normal Retirement Unit Change-Out (NRUC), and 3) Operational  
12 Technologies.

13 1. System Improvement projects are focused on reducing the frequency and  
14 duration of customer outages. Unlike larger scale, longer timeframe  
15 projects like conversions or subtransmission projects, they are smaller scope  
16 projects managed by Regional Operations to immediately address localized  
17 customer issues and complaints. These projects do not exceed \$350,000  
18 and do not require extended planning and design.

19 2. NRUC consists of projects to perform scheduled work that replace assets  
20 determined by equipment engineers to be at end-of-life.

21 3. Operational Technologies consists of the infrastructure and associated  
22 applications that support the AMI platform and data. This also covers  
23 annual work in testing new meter types, designing and installing  
24 configurations, replacing communications equipment, and testing changes  
25 for new equipment.

Line  
No.

1   **Q64. What capital expenditures fall into the General Plant, Tools & Equipment,**  
2           **and Miscellaneous subcategory as shown on Exhibit A-12, Schedule B5.4, page**  
3           **6?**

4   A64. General Plant, Tools & Equipment, and Miscellaneous includes new tools as well  
5       as beyond useful life replacement tools required for field workers to perform their  
6       tasks. It also includes engineering test equipment and substation physical security.  
7       These expenditures ensure that Company workers have the necessary tools and  
8       equipment to conduct and construct field work. Examples of items include meters,  
9       phase sets, and infrared cameras. It also includes direct current hi-potential testers  
10      (Hipoters) that are used to test insulation on cable, breakers, transformers, etc.

11

12   **Q65. What was the Public Lighting Department Project?**

13   A65. The Public Lighting Department (PLD) Project converted former PLD customers  
14       to the Company's distribution system. This project included extending the  
15       Company's overhead and underground system by performing activities like  
16       transformer replacements and line extensions. The project scope was completed  
17       with \$2.2 million of expenditure in 2023 (Exhibit A-12, Schedule B5.4, page 1, line  
18       14, column (b)) with the removal of three breakers from Waterman substation and  
19       final connection of the Detroit Institute of Art. Material closeout costs resulted in a  
20       net credit to the project of \$0.3 million in 2024 (Exhibit A-12, Schedule B5.4, page  
21       1, line 14, column (c)) which was primarily driven by the transfer of unused  
22       materials to other projects in August 2024.

Line  
No.

1 **Part III: Additional Items**

2 **Q66. Are there additional exhibit line items supported by your testimony?**

3 A66. Yes. My testimony also supports capital expenditures related to Portable  
4 Generators (Exhibit A-12, Schedule B5.4, page 10, line 31) and O&M expenditures  
5 related to Miss Dig (Exhibit A-13, Schedule C5.6, page 4).  
6

7 **Q67. What are the Portable Generators in Exhibit A-12, Schedule B5.4, page 10,**  
8 **line 31 under the Infrastructure Resilience and Hardening pillar?**

9 A67. The Company spent \$3.8 million in 2024 to purchase portable generators. The  
10 generators were deployed to vulnerable customers during storms to provide  
11 temporary electrical service. The Company prioritized generators to its most  
12 vulnerable customers based on the estimated duration of storm outage, customer  
13 medical needs, and other factors. These portable generators are separate from the  
14 life critical generators used for critical care and medical emergency customers as  
15 defined by the Commission's Consumer Standards and Billing Practices for  
16 Electric and Natural Gas Service.  
17

18 Deployment of the portable generators is not done by lineworkers and therefore does  
19 not impact restoration time for our customers. Most of the generators allow  
20 customers to use devices that draw less than 2,000 watts. This typically includes  
21 items like refrigerators, freezers, personal medical devices, and sump pumps.

Line  
No.

1 **Q68. Does the Company have expenditures related to Miss Dig / Damage**  
2 **Prevention?**

3 A68. Yes. The Company's expenditures related to Miss Dig / Damage Prevention are  
4 shown in Exhibit A-13, Schedule C5.6, page 4.

5

6 **Q69. What projected adjustments did you make to O&M as reflected in column (i)**  
7 **of Exhibit A-13, Schedule C5.6, page 4?**

8 A69. Line 2 reflects an adjustment related to increased Miss Dig 811 membership fees  
9 for \$0.1 million. Line 3 reflects an adjustment for Contractor Staking for \$2.9  
10 million. All DTE Electric staking is performed by contractors. In 2024, the  
11 Company issued a request for proposal ("RFP") for staking resulting in negotiated  
12 contracts with two vendors in 2025.<sup>13</sup> Based on contract negotiations, market  
13 conditions, and volume, unit staking costs have increased.

14

15 **Q70. Does this complete your direct testimony?**

16 A70. Yes, it does.

17

---

<sup>13</sup> Previously, all staking was sole sourced to one vendor.

**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-21860

QUALIFICATIONS  
  
AND  
  
DIRECT TESTIMONY  
  
OF  
  
RACHEL C. STEUDLE

**DTE ELECTRIC COMPANY**  
**QUALIFICATIONS AND DIRECT TESTIMONY OF RACHEL C. STEUDLE**

Line  
No.

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

2    A1.    My name is Rachel Steudle (she/her/hers). My business address is One Energy  
3           Plaza, Detroit, Michigan 48226. I am employed by DTE Electric Company (DTE  
4           Electric or Company).

5  
6    **Q2.    On whose behalf are you testifying?**

7    A2.    I am testifying on behalf of DTE Electric.  
8

9    **Q3.    What is your educational background?**

10   A3.    I graduated from Skidmore College in 2012 with a Bachelor of Arts in Economics  
11           and Environmental Studies. In 2015, I completed a Master of Arts in Applied  
12           Economics, and a Master of Science in Energy Systems from the University of  
13           Michigan.

14  
15   **Q4.    What is your work experience?**

16   A4.    I began my career with DTE Energy in 2015 and have been employed there since.  
17           I joined DTE Energy in the Corporate Strategy team and spent four years supporting  
18           a broad range of strategic projects, primarily focused on DTE Electric. I concluded  
19           my time with Corporate Strategy as an Associate, responsible for leading and  
20           managing strategic projects with minimal oversight. In 2019, I joined DTE Electric  
21           when I was promoted to Manager, Tree Trimming, where I was responsible for  
22           leading the tree trim scheduling process, managing the program's budget, and  
23           supporting strategic efforts. In 2020, I was promoted to the Strategy Manager role  
24           for Tree Trimming. In this position, I continued my previously-stated  
25           responsibilities while taking responsibility for developing the annual and five-year

Line  
No.

1 maintenance plans, leading all regulatory activities, negotiating contracts with the  
2 tree trimming vendors and overseeing the planning and auditing field team. In 2023,  
3 I accepted a new role in DTE Energy's project management organization (PMO)  
4 and was responsible for leading the long-term planning for distribution capital  
5 projects. Late 2023, I returned to the Tree Trimming team to assume the Director  
6 role.

7

8 **Q5. What are your current job responsibilities?**

9 A5. I am the Director of Tree Trimming; I am responsible for all aspects of the strategy  
10 and execution of the Tree Trimming Program. This includes contract negotiations,  
11 strategy, planning, auditing, execution, outage restoration trimming, customer  
12 satisfaction, workforce development and scheduling.

13

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

16 A6. Yes, I have sponsored testimony in the following cases:

17 U-21534 DTE Electric Company 2024 Rate Case

18 U-21799 DTE Electric Company Tree Trim Deferral Accounting

Line  
No.

1 **Purpose of Testimony**

2 **Q7. What is the purpose of your testimony?**

3 A7. The purpose of my testimony is to:

- 4 • Discuss the importance of and progress made in DTE Electric's vegetation
- 5 management ("Tree Trimming") program;
- 6 • Provide details related to the Company's Tree Trimming Surge Program that
- 7 will deliver on the reliability goals established in the Company's Distribution
- 8 Grid Plan (DGP);
- 9 • Describe the customer benefits of the Company's Tree Trimming Surge
- 10 Program to-date;
- 11 • Support the Operations and Maintenance (O&M) expenses related to tree
- 12 trimming efforts for the historical test period ending December 31, 2023, and
- 13 the projected base O&M expenses for January 1, 2026 to December 31, 2026;
- 14 • Discuss the future of the Tree Trimming program once the Surge is complete;
- 15 including the introduction of risk-based cycles and proposed specification
- 16 changes the Company is exploring.

17

18 **Q8. Are you sponsoring any exhibits in this proceeding?**

19 A8. Yes, I am supporting the following exhibits:

| 20 | <u>Exhibit</u> | <u>Schedule</u> | <u>Description</u>                                  |
|----|----------------|-----------------|-----------------------------------------------------|
| 21 | A-12           | B5.4            | Projected Capital Expenditures – Distribution Plant |
| 22 |                |                 | (Pages 1-2, 14 and 16-23)                           |
| 23 | A-13           | C5.6.1          | Projected Tree Trimming Expenses                    |
| 24 | A-22           | L1              | Projected Value of Tree Trimming Surge Program      |
| 25 | A-31           | U1              | 2025 Annual Tree Trim Report                        |



Line  
No.

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

2     A9.    Yes.

3

4     **Outline of Testimony**

5     **Q10.   How is your testimony organized?**

6     A10.   My testimony is organized as follows:

- 7           •   Part I: Overview of the Company's Tree Trimming Program and the Surge
- 8           •   Part II: Final Year of the Surge
- 9           •   Part III: Post-Surge (2026 and Beyond)

10

11                   **Part I: Overview of the Company's Tree Trimming Program**

12    **Q11.   Can you please describe the Company's Tree Trimming Pillar within the**  
13           **Distribution Grid Plan (DGP)?**

14    A11.   The Tree Trimming Pillar, as introduced by Company Witness Chiu, focuses on  
15           keeping vegetation (e.g., trees, brush, vines) clear of the Company's overhead  
16           electrical equipment, including poles, wires, transformers, etc. The objectives of  
17           these investments are to reduce tree-related safety hazards and to reduce the volume  
18           of tree-related trouble cases, thereby improving customer reliability. All vegetation  
19           management investments are made through the Company's Tree Trimming  
20           Program.

21

22    **Q12.   What is the biggest root cause of customer outages?**

23    A12.   As discussed in the Company's 2023 DGP (Case No. U-20147), tree interference  
24           remains one of the leading drivers of customer outages. Historically, tree-caused  
25           outages accounted for two-thirds of the time that customers spent without power.

Line  
No.

1 The Company's Tree Trimming Program reduces the frequency of tree contact with  
2 the distribution and subtransmission system. The ongoing, successful execution of  
3 this program allows DTE Electric to continuously improve the overall reliability of  
4 electric service.

5

6 **Q13. What is the best way to reduce tree-related outages?**

7 A13. A robust Tree Trimming Program improves system reliability, including a  
8 reduction of the volume and duration of outages, wire-downs, and other non-outage  
9 trouble events. Achieving customers' desired level of reliability requires that the  
10 program be funded to maintain a tree-trim cycle that permits the trimming of a  
11 circuit to prevent vegetation interference with the Company's wires and become  
12 hazards.

13

14 **Q14. What is the Company's Tree Trimming Program?**

15 A14. Beginning in 2016, the Company has executed a robust program to address tree  
16 interference by trimming and removing trees to an enhanced specification known  
17 as the Enhanced Tree Trimming Program (ETTP). The ETTP specification was  
18 designed to reclaim right of ways, remove and reduce vegetation hazards from  
19 distribution infrastructure, and properly define trim specifications for vegetation  
20 encroachment. Distinguishing elements of the ETTP specification compared to the  
21 prior specification included expanding clearances around equipment, addressing  
22 overhang (branches extending above the equipment), and when possible, removing  
23 appropriate vegetation.

Line  
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1 In addition to introducing this new specification, the Company proposed the Tree  
2 Trim Surge (the Surge) in 2018 in Case No. U-20162. The purpose of the Surge  
3 was to secure the necessary funding to trim all circuit miles to the ETPP  
4 specification by the end of 2025. In Case No. U-20162, the Company proposed  
5 maintaining a five-year cycle (three-year cycle for subtransmission) for all miles,  
6 including those trimmed in the early years of the Surge. This means a circuit  
7 trimmed to the ETPP specification in 2016 or later would be maintained on a five-  
8 year cycle length while the Company addressed additional off-cycle miles in the  
9 later years of the Surge.

10

11 **Q15. How long did the Company forecast the Tree Trim Surge would take?**

12 A15. The Company forecasted the Surge would span seven years, or 2019 through 2025.

13

14 **Q16. What were the expected benefits of the Surge?**

15 A16. The benefits of the Surge for customers were two-fold, 1) provide improved  
16 reliability by mitigating tree-caused outages, 2) create future cost savings through  
17 reduced maintenance trimming costs and reduced reactive costs. These benefits  
18 were captured in Exhibit A-22 Schedule L1 and discussed in detail in Case No. U-  
19 20162, U-20561 and U-20836.

20

21 **Q17. Has the Commission supported the Tree Trimming Surge?**

22 A17. Yes, the Commission approved the first three years of regulatory asset treatment in  
23 Case No. U-20162. In subsequent rate cases, the Commission has continued to  
24 support the Tree Trimming Surge, approving incremental years of regulatory asset  
25 treatment and the requested base O&M increases.

Line  
No.

1 **Q18. What is the progress towards completing the Surge as of the end of 2024?**

2 A18. The Company trimmed or removed trees across 4,348 miles in 2024, bringing the  
3 system to 92% on-cycle. The Company's goal is to be 100% on-cycle by the end  
4 of 2025.

5

6 **Q19. How does the Company define "on-cycle?"**

7 A19. On-cycle means that the trees associated with the circuit miles have been trimmed  
8 and/or removed to the ETTP specification at least once and are now on a regular  
9 maintenance cycle for future years. Miles that are not on-cycle are considered  
10 "reclaim". Reclaim miles are circuits whose trees have not been trimmed or  
11 removed to the ETTP specification. These circuits have trees that have not been  
12 trimmed or removed since at least 2015.

13

14 **Q20. What is the Company's maintenance cycle for on-cycle miles?**

15 A20. The Company distinguishes cycle length based on the voltage of the circuit. For  
16 subtransmission circuits (24kV and 40kV), the cycle length is three years. For  
17 distribution circuits (4.8kV, 8.3kV and 13.2 kV), the target cycle length has been  
18 five years. The Company is introducing a variable, risk-based cycle for distribution  
19 circuits, which would mean some circuits have a longer or shorter cycle length  
20 based on certain criteria. This approach is discussed in detail later in this testimony  
21 as part of "Part III – Post-Surge (2026 and Beyond)."

22

23 **Q21. Have the ETTP specifications been applied consistently throughout the Surge?**

24 A21. The clearance and trimming specification varies by voltage, tree species, and  
25 relevant overhead equipment. The ETTP specifications are applied consistently

Line  
No.

1 throughout the Company's service territory based on the aforementioned factors.  
2 The specification is focused on clearing vegetation within the right-of-way to  
3 mitigate hazards to overhead equipment. In addition, while trimming or removing  
4 trees in the right-of-way, the Company identifies priority trees outside the right-of-  
5 way that could pose a risk and attempts to mitigate this risk by removing the trees.

6

7 **Q22. Does the Tree Trimming Program include auditing (inspections)?**

8 A22. Yes. The Tree Trimming program performs quality inspections on all maintenance  
9 work to ensure compliance to specifications outlined by the ETP.

10

11 **Q23. How are the inspections conducted and to what standards?**

12 A23. Inspections are conducted to validate quality standards determined by International  
13 Society of Arboriculture (ISA) and ANSI300A trimming guidance against the trim  
14 plans for the specified work completed on a circuit. Such inspections are performed  
15 by certified arborists who are either internal to the Company or are from a third-  
16 party vendor who is not associated with the Tree Trimming vendors.

17

18 **Q24. When does inspection take place?**

19 A24. Inspections are conducted typically within 30 days from the time the entirety of the  
20 work for all circuits fed from a substation is completed. Once all the work is  
21 reviewed and approved by the arborist, the closure of that work is approved.

22

23 **Q25. What happens when a non-compliant result is discovered?**

24 A25. Any non-compliance of a tree trim task against the standard is provided to the  
25 trimming vendor to be remediated within 30 days at no additional cost to the

Line  
No.

1 Company. An auditor then inspects the area again to ensure the remediation is  
2 performed in a satisfactory manner.

3

4 **Q26. How does the Company track tree work associated with the maintenance**  
5 **program and the quality inspections?**

6 A26. The Company has a work management system that is used for the planning,  
7 execution, and inspection of all maintenance trimming. This program allows for  
8 planners to identify specific tasks (trims or removals of each individual tree / brush)  
9 on a property, the system captures the species, size and location of each task. The  
10 trimmers reference and use the work management system to execute the planned  
11 work. The inspection team uses the same system to identify the work that was  
12 completed and to inspect the tasks for potential defects. Inspection results are then  
13 accessible to the contractor through the work management system. This process  
14 allows for streamlined plans, electronic records of work completed, and a database  
15 of tree work for the Company to leverage for future planning and analysis.

16

17 **Tree Trimming Surge Effectiveness**

18 **Q27. How has the Company measured or tracked the effectiveness of the Surge**  
19 **Program?**

20 A27. The Company developed a methodology that compared the performance of on-  
21 cycle circuits whose trees were trimmed or removed to the ETPP specification  
22 relative to reclaim circuits. This approach enables the Company to understand the  
23 relative benefit of introducing the ETPP-specification compared to the status quo  
24 where the Surge was not executed.

Line  
No.

1     **Q28. Can you elaborate on the methodology?**

2     A28. The Company used the methodology outlined in Case No. U-20561 as well as in  
3     the Tree Trimming Annual Report submitted in the Case No. U-20162 docket and  
4     described in Exhibit A-31, Schedule U1 (2025 Annual Tree Trim Report), for  
5     reference.

6     Table 1 below includes outage and event data through the end of the 2023 calendar  
7     year. The methodology used to calculate ETP Performance for all distribution  
8     circuits utilizes the average of three years of pre-trim ETP tree-outage events and  
9     compares it to each year post trimming/removal. All post-trim year results of the  
10    same year were then summed to increase the sample size (as an example, all post-  
11    trim year 1 results are summed). The difference between the before  
12    trimming/removal performance and the post trimming/removal performance was  
13    used to create the “% Change in Outage Event Reduction for ETP circuits.” To  
14    create a control group for comparison, the same methodology was used for the  
15    remainder of circuits not trimmed/removed to the ETP<sup>1</sup> (Non-ETP circuits),  
16    which is identified as “% Change in Outage Event Reduction for Non-ETP  
17    circuits.” To account for natural weather variation, the performance of the control  
18    group is subtracted from the ETP circuit performance to provide an accurate  
19    representation of the true impact of the ETP.

20

21    **Q29. What has been the improvement on circuits trimmed/removed to the ETP**  
22    **specification compared to the non-ETP control group and can you provide**  
23    **the improvements for tree-related outage events, customer interruptions,**  
24    **customer minutes of interruptions, and wire-downs?**

---

<sup>1</sup> This group consists of circuits that have not been trimmed to the ETP specification and are considered off-cycle.

Line  
No.

1 A29. Table 1 shows the difference of outages, customer interruptions, minutes  
2 interrupted and wire-downs between the distribution circuits trimmed to the ETPP  
3 specification versus distribution circuits not trimmed to the ETPP specification.  
4 The data in Table 1 covers 1-4 years post trimming. This data represents the  
5 Company's reliability data through 2023. As discussed, continuing this  
6 methodology for the final years of the Surge was not appropriate given the  
7 shrinking population of non-ETPP circuits.

8

9 **Table 1** Tree-Related ETPP Reliability Performance Compared to Non-ETPP<sup>2</sup>

|                      | Number of<br>Dist.<br>Circuits<br>ETPP<br>Trimmed | Outage<br>Events<br>Difference | Customer<br>Interruptions<br>Difference | Customer<br>Minutes of<br>Interruption<br>Difference | Post-ETPP<br>Wire-Down<br>Difference |
|----------------------|---------------------------------------------------|--------------------------------|-----------------------------------------|------------------------------------------------------|--------------------------------------|
| 1 Year<br>Post Trim  | 2063                                              | -54.0%                         | -57.9%                                  | -32.4%                                               | -55.4%                               |
| 2 Years<br>Post Trim | 1442                                              | -36.8%                         | -59.3%                                  | -8.1%                                                | -56.8%                               |
| 3 Years<br>Post Trim | 974                                               | -43.8%                         | -48.6%                                  | 22.4%                                                | -39.8%                               |
| 4 Years<br>Post Trim | 491                                               | -11.1%                         | -40.7%                                  | 6.4%                                                 | -15.3%                               |

10

11 **Q30. Does the Company intend to keep using the same methodology?**

12 A30. No – as discussed in Case No. U-21534, the Company recognizes the usefulness of  
13 this methodology is beginning to diminish with the majority of circuits now  
14 trimmed to the ETPP specification. The remaining non-ETPP population is  
15 becoming insignificant to be an effective comparison to ETPP trimmed circuits.  
16 Moving forward the Company plans to develop and implement a new methodology  
17 to track the ongoing performance of maintaining the Company's current program.

---

<sup>2</sup> Section 3 of the Tree Trim Annual Report, as referenced in Case No. U-20162 and filed on March 1, 2024, provides further details pertaining to the figures presented in Table 1.



Line  
No.

1 **Q31. Can you elaborate on the new methodology?**

2 A31. Yes. The new method of measuring Tree Trim effectiveness is part of the  
3 Reliability Model, sponsored by Witness Kryscynski. The new methodology  
4 evaluates the effectiveness of tree trimming by developing a pre-trimming baseline  
5 of three years' worth of non-major event day (MED)<sup>3</sup> historical circuit outage data  
6 prior to maintenance trimming. Then comparing that baseline to the non-MED  
7 event data for each year post-trimming until the circuit is due for trimming again.  
8 The outage data is focused on tree-related events only, using the cause codes for  
9 each event to make that categorization.

10

11 **Q32. What are the results of this analysis?**

12 A32. In the first year after trimming, circuits experience a 44% reduction in outages  
13 compared to the baseline. The effectiveness reduces each subsequent year as the  
14 vegetation begins to regrow.

15

16 **Table 2** Tree Trim Reliability Improvement<sup>4</sup>

| <b>Years Post-Trim</b>                         | <b>1 Year</b> | <b>2 Years</b> | <b>3 Years</b> | <b>4 Years</b> | <b>5 Years</b> |
|------------------------------------------------|---------------|----------------|----------------|----------------|----------------|
| Relative Outage Reduction Compared to Baseline | -44%          | -33%           | -22%           | -11%           | 0%             |

17

18 **Q33. Does the Company feel that the Tree Trim Surge has been effective in**  
19 **providing reliability benefits to customers?**

---

<sup>3</sup> **Major Event Day (MED)**, as defined by the IEEE, refers to a day when a significant event occurs that exceeds the normal operational limits of an electric power system. These events typically involve widespread power outages affecting at least 10% of customers within an operating area for a sustained period

<sup>4</sup> Refer to U-21860 Reliability Model Exhibit A-23, Schedule M12 for the figures presented in Table 2.

Line  
No.

1 A33. Yes, as demonstrated with the data above and the feedback the Company has  
2 received from customers and communities, the Surge has delivered improved  
3 reliability and as the Company continues to maintain rights-of-way and clearances,  
4 these improvements are expected to be sustained.

5

6

**Part II – Final Year of the Surge**

7 **Q34. When was the Tree Trimming Surge originally proposed to be completed?**

8 A34. In Case No. U-20162, the Company proposed trimming the full system to the ETPP  
9 specification and maintaining on-cycle miles to a five-year cycle (three-year cycle  
10 for subtransmission) by the end of 2025.

11

12 **Q35. Is the Company on track to complete the Surge in 2025?**

13 A35. Yes, as of the end of 2024, the Company is 92% on-cycle, with the remaining 2,259  
14 reclaim miles on the 2025 plan.

15

16 **Q36. What was the Company's target for miles in 2024?**

17 A36. The Company's target for miles in 2024 was 4,003. The Company overachieved  
18 this target by 345 miles.

19

20 **Q37. Can you elaborate on how the Company was able to overachieve its 2024  
21 target?**

22 A37. Yes, the Company began the year with a strong tree trimming workforce and did  
23 not require a significant ramp-up in resources. Having the necessary trimmers on  
24 property from the start of the year, coupled with favorable weather through the  
25 summer months, enabled the Company to be ahead of schedule entering the fall. To

Line  
No.

1 manage the workforce for the remainder of the year, the Company requested to pull  
2 ahead a portion of the approved regulatory asset for 2025 into 2024.

3

4 **Q38. How much funding did the Company request to pull ahead?**

5 A38. The Company requested as part of Case No. U-21799 to pull ahead up to \$15  
6 million of the approved regulatory asset for 2025 into 2024. The Commission  
7 approved the Company's request on October 10<sup>th</sup>, 2024.

8

9 **Q39. How much of the approved \$15 million pull ahead funding did the Company**  
10 **spend in 2024?**

11 A39. The Company spent \$1.7 million in 2024. The pull ahead spend was significantly  
12 impacted by the very active 2024 hurricane season (11 hurricanes, five of which  
13 were category 3 or higher). As a result, the Company's tree trim crews were  
14 requested by southern utilities and subsequently re-assigned to support restoration  
15 efforts outside of Michigan. The Company anticipates spending the remaining  
16 \$13.3 million of this pull-ahead regulatory asset in 2025.

17

18 **Q40. What is the approved Tree Trim Budget for 2025?**

19 A40. The 2025 budget is \$238 million, which includes the \$87 million incremental  
20 regulatory asset that was approved in Case No. U-21534.

21

22 **Q41. What is the 2025 miles target?**

23 A41. The 2025 miles target is 6,614 miles, of which 2,259 are the remaining reclaim  
24 miles necessary to address for completion of the Surge.

Line  
No.

1 **Q42. Does the Company have sufficient resources to complete this volume of miles?**

2 A42. Yes, as of March 2025, the Company had over 1,300 trimmers on property  
3 executing the Company's 2025 maintenance plan. The Company monitors weekly  
4 production to ensure the plan is completed this year, with a heavy focus on the final  
5 reclaim miles. If the Company identifies a risk of falling behind, the Company will  
6 bring incremental resources to ensure the plan is completed.

7

8

**Part III – Post-Surge (2026 and Beyond)**

9 **Q43. Can you define "post-Surge"?**

10 A43. Being in the final year of the Surge, the Company is developing what the Tree  
11 Trimming Program will look like once it is fully on-cycle, beginning in 2026,  
12 defined as the "post-Surge" period.

13

14 **Q44. What is the Company's vision for the post-Surge program?**

15 A44. One of the defining aspects to the Company's post-Surge Tree Trimming Program  
16 will be the transition to risk-based cycles for the Company's distribution circuits.

17

18 **Q45. Why is the Company transitioning to variable, risk-based cycles?**

19 A45. As the Company entered the final year of the Surge, it recognized opportunities to  
20 adjust the target cycle for different parts of the system utilizing technology such as  
21 Light Detection and Ranging (LiDAR), a remote sensing technology that uses laser  
22 light to identify and measure vegetation risk. Adjusting cycle lengths based on tree  
23 species' growth rates, risk of outages, and cost of trimming will further improve  
24 trimming efficiencies and provide improved reliability benefits to customers. With  
25 the acquisition of LiDAR data (2021) combined with tree species data the Company

Line  
No.

1 has acquired over the course of the Surge program, DTE Electric has the necessary  
2 information to make data-driven improvements to the program.

3

4 Furthermore, the idea of variable cycles was raised by intervenors and the  
5 Commission in Case No. U-20836. In Case No. U-20836, the Commission ordered  
6 the Company to continue to explore efficiency improvements and benefits from a  
7 variable cycle for the Tree Trimming program, and the Company is complying with  
8 that directive. The DTE Electric Utility Distribution Audit Report<sup>5</sup> (“Liberty  
9 Audit”), conducted by Liberty Consulting Group and filed in Case No. U-21305,  
10 also recognized the opportunity to explore risk-based cycles, stating “while the  
11 five-year cycle establishes a sound baseline for now... [DTE’s] plan to examine  
12 cycle alterations should remain a priority.”<sup>6</sup>

13

14 **Q46. How is a variable, risk-based cycle different from a five-year cycle?**

15 A46. A fixed-year cycle (i.e., five-year cycle) has been the industry standard until  
16 recently. The emergence of remote sensing tools such as LiDAR, and advanced  
17 data analytics for vegetation management programs allows companies to begin  
18 considering variable cycles that align with the Company’s overhead circuits’  
19 unique risk factors discussed below.

20

21 Moving towards a variable, risk-based cycle would be a refinement to the  
22 Company’s maintenance program. The five-year cycle is based on the *average*  
23 growth rates and tree densities across the entire system and their expected *average*

---

<sup>5</sup> Though the title indicates DTE Energy Company (DTE Energy), the audit findings apply to DTE Electric, a wholly owned subsidiary of DTE Energy. The DTE Electric Audit Reports are available in filing ## U-21305-0012 and U-21305-0013 at <https://mi-psc.my.site.com/s/case/5008y000005KkdgAAC/> (accessed February 15, 2025).

<sup>6</sup> Case No. U-21305; Liberty Audit, Part Two, pg. 52

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1 spatial relation to the conductor. There are areas across the territory with higher  
2 tree densities and faster-growing species that grow back into wires prior to five  
3 years, in other words, there are variances to the averages discussed. Conversely,  
4 there are areas with slower-growing species that could go longer between cycles  
5 before interfering with the conductor. Moving towards a risk-based cycle would  
6 move higher risk areas to a shorter cycle, and lower risk areas to a longer cycle  
7 instead of uniformly trimming every area on a five-year cycle.

8

9 **Q47. Do other utilities use a risk-based cycle?**

10 A47. Yes. Based on my understanding of benchmarking and other information, the  
11 Company has identified other utilities in the industry exploring or introducing  
12 variable, risk-based variable cycles.

13

14 **Q48. What does the Company foresee as the benefit from this shift?**

15 A48. The Company expects that moving towards a risk-based cycle will result in  
16 trimming efficiencies and improved reliability for high-risk areas. Based on the  
17 nature of variable cycle programs, the Company anticipates the need to trim high-  
18 risk areas more frequently and low-risk areas less frequently, resulting in an overall  
19 more efficient use of resources. In addition, more frequent trimming in high-risk  
20 areas should provide reliability benefits to customers without sacrificing reliability  
21 in low-risk areas.

22

23 **Q49. How did the Company determine the length of a risk-based cycle?**

24 A49. The Company developed a risk prioritization model that leverages remote sensing  
25 data (e.g., LiDAR), advanced analytics, and machine learning to estimate the

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1 probability of vegetation-driven failures and determine optimal trim cycles for each  
2 individual circuit.

3

4 **Q50. Has the Company deployed the risk prioritization model?**

5 A50. Yes, while the focus has continued to be finishing the Tree Trim Surge, the  
6 Company began leveraging the recommendations of the model to defer miles  
7 already trimmed to the ETTP specification that are due for trimming based on the  
8 five-year cycle.

9

10 **Q51. Can you elaborate?**

11 A51. Based on the recommendation of the model, the Company deferred approximately  
12 2,000 “on-cycle” miles from 2024 and plans to defer approximately 3,700 “on-  
13 cycle” miles from the 2025 plan. The purpose of this was two-fold: begin learning  
14 and testing the model, and repurpose more funding for the remaining reclaim miles  
15 that still need to be trimmed.

16

17 **Q52. How were these miles selected?**

18 A52. Miles selected for deferral were based on the recommended cycle length from the  
19 Company’s risk-based model. The model considers the tree species growth rates  
20 and the potential customer impact on those circuits. Therefore, circuits that are  
21 selected for deferral pose a collectively lower reliability risk and allow for the  
22 prioritization of higher risk circuits to be trimmed.

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1     **Q53. How specifically does the Company evaluate performance of circuits that are**  
2     **selected for deferral as compared to the Company’s system average?**

3     A53. For the miles that were deferred and not trimmed in 2024, the Company evaluated  
4     their tree-related SAIFI<sup>7</sup> for the year. In 2024, SAIFI for the deferred circuits was  
5     0.15 while the overall system SAIFI was 0.18. In other words, these results  
6     demonstrate that the deferred circuits were on par with the system average for 2024.  
7     Further, the deferred circuits’ 2024 SAIFI performance was 0.15 compared to 0.32  
8     in 2023, demonstrating no adverse impact in being deferred an additional year.  
9     Though 2024 was the first year in which the Company employed the risk-based  
10    model to prioritize other higher risk circuits, the results were encouraging. The  
11    Company is planning to defer over 50% more circuits in 2025 than 2024 and will  
12    closely evaluate performance of those circuits to ensure reliability is in line with  
13    the Company’s system average. The Company is not anticipating pulling ahead /  
14    shortening the trimming cycle for any circuit in 2025.

15

16    **Q54. Does the Company anticipate further adjustments or refinements to its risk-**  
17    **based model after it is implemented?**

18    A54. Yes, it is intended to be a dynamic model. As the Company continues to execute  
19    its annual maintenance plan, data will be collected and incorporated into the model  
20    that will allow for further trim cycle refinement. As an example, tree removals are  
21    specifically tracked and inventoried. As the Company removes “good removal  
22    candidates (GRCs),” the model will incorporate this adjustment to risk for a tree-  
23    related outage or event and provide an updated trim cycle. Conversely, if the

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<sup>7</sup> SAIFI stands for System Average Interruption Frequency Index; in this analysis, only tree-related outages, excluding major event days were used



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Company sees a higher degradation in SAIFI on a particular circuit for example, this will increase this circuit's risk profile.

**Q55. If the Company fully leverages this model, what is the expected average cycle-length?**

A55. When fully implemented to include both pull ahead and deferred miles, the Company estimates the average cycle length will be 5.8 years for distribution miles. When including sub-transmission miles, the Company's adjusted average cycle length is 5.6 years. Table 3 shows the Company's proposed trim cycle length based on the risk-based model.

**Table 3 Risk-Based Trim Cycle**

| <b>Circuit Type</b> | <b>Cycle Length (Years)</b> | <b>% of Customers</b> | <b>% of System Miles</b> |
|---------------------|-----------------------------|-----------------------|--------------------------|
| Sub-transmission    | 3                           | N/A                   | 8%                       |
| Distribution        | 4                           | 37%                   | 17%                      |
| Distribution        | 5                           | 30%                   | 20%                      |
| Distribution        | 6                           | 21%                   | 19%                      |
| Distribution        | 7                           | 12%                   | 36%                      |

**Q56. Does the Company have concerns that over half of its circuit miles are expected to be on a trim cycle greater than the current five-year program?**

A56. No. As previously explained, the Company's risk-based model accounts for tree species and vegetation growth profiles as well as density of customers per circuit. While the majority of distribution miles will be greater than a five-year cycle, Table 3 illustrates that over two-thirds of DTE Electric's customers will remain on a five-year cycle or move to a four-year cycle.

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1 **Q57. Will the shift to risk-based require additional inspections and spot trimming?**

2 A57. Yes, to ensure the Company is maintaining the necessary clearances and addressing  
3 cycle-buster trees, it will put into place a mid-cycle inspection program in which a  
4 portion of the distribution circuits are inspected 2-3 years post trimming. During  
5 these inspections, emerging hot spots within the right-of-way will be identified  
6 along with trees that pose a hazard both inside and outside of the right-of-way.

7

8 **Q58. When does the Company plan to fully implement the use of a risk-based cycle?**

9 A58. Beginning in 2026 the Company anticipates moving fully to risk-based cycles. This  
10 process will take several years since the cycle lengths will be adjusted as circuits  
11 previously trimmed come up for their recommended trim cycle. This transition will  
12 enable the program to optimize resources and maintain, and potentially improve,  
13 tree-related reliability for customers.

14

15 **Q59. With the conclusion of the Surge, is the Company considering areas of**  
16 **improvement and changes to the specification?**

17 A59. Yes, the Company has performed a full review of its tree trimming program, which  
18 included a third-party assessment, peer benchmarking, and a reconciliation of how  
19 the actual benefits of the Surge aligned to expectations. In addition, the Company  
20 took this opportunity to incorporate feedback and recommendations from prior rate  
21 cases and the Liberty Audit.

22

23 **Q60. What were the findings of this analysis?**

24 A60. The Company has identified three areas to further support customer reliability and  
25 sustainable savings:

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1                   **1) Remove species-specific overhang** – target removal of overhang of  
2                   tree species most susceptible to causing overhang-related outages. The  
3                   current specification requires removal of overhang up to the first  
4                   protective device, which makes up ~20% of the distribution miles, but  
5                   does not include the removal of any overhang beyond the first protective  
6                   device.

7                   **2) Improve the clearing of the “floor”** – this refers to clearing the area  
8                   directly under the overhead equipment from vegetation such as brush  
9                   and small trees that will eventually grow into this infrastructure.  
10                  Removing this type of vegetation ensures the Company has a well-  
11                  defined, clear corridor along the overhead equipment and reduces the  
12                  need to trim or remove trees in future tree trimming cycles.

13                  **3) Establish an outside-the-right-of-way (OROW) Tree Risk Program**  
14                  – implement a dedicated program to address trees outside the  
15                  Company’s OROW that pose a risk to failing/falling into the Company’s  
16                  overhead equipment.

17

18   **Q61. How are these changes different from the existing ETP specification and**  
19   **program?**

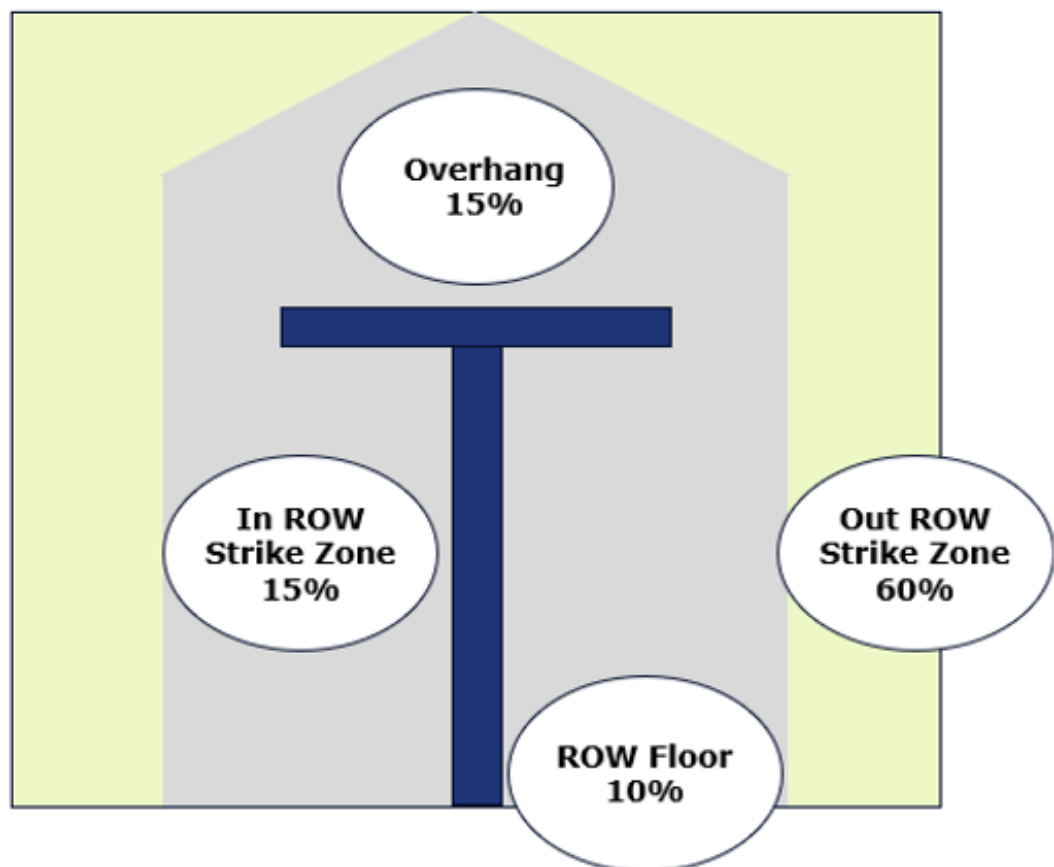
20   A61. These changes build on the foundation the Company has created through executing  
21   and completing the Tree Trim Surge. Specifically, these changes would expand the  
22   vegetation the Company addresses and removes from the system. Fewer trees and  
23   vegetation around the Company’s equipment further minimizes the risk of tree  
24   interferences, especially during extreme weather events.

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1 **Q62. What benefits would these changes provide?**

2 A62. As discussed above, these changes would help eliminate additional vegetation-  
3 related threats to overhead equipment. These changes target the types of tree  
4 outages the industry typically sees for an on-cycle system (Figure 1<sup>8</sup> and Table 4).  
5

6 **Figure 1** Types and Likelihood of Tree-Caused Outages for an On-Cycle System<sup>8</sup>



<sup>8</sup> Source of Figure 1 is third-party report commissioned by the Company by Iapetus Infrastructure Services

Line  
No.

1 **Table 4** Opportunities to Address Types of Tree Outages

| Tree Outage Types                   | Opportunity to Address with Changes to DTE's Specification                                                                                                                                                                                                             |
|-------------------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <b>Overhang</b>                     | <b>Remove softwood overhang</b> <ul style="list-style-type: none"> <li>Expand removal of softwood overhang beyond the first protective device</li> <li>Currently only remove overhang to the first protective device, which is ~20% of the primary OH miles</li> </ul> |
| <b>In ROW Strike Zone and Floor</b> | <b>Improve the clearing of the "floor"</b> <ul style="list-style-type: none"> <li>Increase removals of smaller trees and brush before they grow into larger threats to equipment – especially the secondary</li> <li>Identify and remove hazard trees</li> </ul>       |
| <b>Out ROW Strike Zone</b>          | <b>Establish an OROW Tree Risk Program</b> <ul style="list-style-type: none"> <li>Increase frequency of patrols to identify and remove OROW hazard trees (every 2-3 years)</li> </ul>                                                                                  |

2

3 **Q63. Are there other reasons the Company is considering these specific changes?**

4 A63. Yes, in recent years the Company observed the number and severity of weather  
5 events increase as seen in Figures 2 and 3 shown below. The proposed changes  
6 would help mitigate common tree-related issues that the Company observes during  
7 severe weather/storm events and improve the resiliency of the grid. Beyond  
8 reducing tree-related issues, clearing of the floor would yield additional benefits by  
9 improving and expediting access to outages (tree and non-tree related) and broken  
10 equipment during severe weather events. Currently, overhead restorations can be  
11 delayed due to significant vegetation within the ROW, and if these areas are better  
12 cleared and maintained, crews will be able to identify and address outages faster.

13

14 During the 2023 Ice Storm, the vast majority of outages caused by overhang were  
15 from Siberian Elm and Silver Maple trees, with large branches breaking off past  
16 the first protective device (Figure 2). These tree species are included in the

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1           proposed tree species the Company would remove overhang on, throughout the  
2           circuit.

3

4           **Figure 2**           Siberian Elm with Broken Overhang during 2023 Ice Storm



5

6           **Figure 3**           Photos of Tree-Related Outages During March 2025 Weather

| Examples of Outside of Right-of-Way                                                 |                                                                                                                 | Example of Overhang                                                                                         |
|-------------------------------------------------------------------------------------|-----------------------------------------------------------------------------------------------------------------|-------------------------------------------------------------------------------------------------------------|
| <b>BALDW8014 CIRCUIT</b><br><i>3,435 Customers Impacted and Last Trim in 2024</i>   | <b>ZEBRA9474 CIRCUIT</b><br><i>2,174 Customers Impacted, Last Trim in 2020 and on the 2025 Maintenance Plan</i> | <b>MOTT8124 CIRCUIT</b><br><i>50 Customers Impacted, Last Trim in 2020 and on the 2025 Maintenance Plan</i> |
|  |                             |                        |

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1 In 2024 and 2025, the Company observed similar trends in overhang and OROW  
2 trees causing outages during weather events. In March 2025, the Company  
3 experienced multiple higher than normal weather days where wind speeds  
4 exceeded 40 miles per hour, and during these days there was an increase in  
5 outages, many of which were related to trees.

6

7 **Q64. Would changes to the specification provide benefits beyond reliability and**  
8 **resiliency?**

9 A64. Yes, the Company expects that implementing these specification changes would  
10 reduce future costs associated with tree trimming in two ways. First, fewer tree-  
11 related events would yield savings in terms of reactive work. Second, the clearing  
12 and removal of vegetation in the floor during maintenance trimming will reduce the  
13 future cost of maintaining that area. The magnitude of reduction in future cost for  
14 maintenance trimming will be based on the volume of vegetation successfully  
15 removed and the ability to maintain the right-of-way through appropriate herbicide  
16 use.

17

18 **Q65. Has the Company completed benchmarking or research to understand how**  
19 **these changes align with peer utilities?**

20 A65. Yes, the Company conducted a specification and program benchmarking study last  
21 year to understand how the Company's program is similar / dissimilar to other  
22 utilities. In addition, the Company has held ad-hoc meetings with other utilities to  
23 learn and explore common topics with peers.

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1     **Q66. Can the Company share the findings of the benchmarking study related to**  
2     **trimming specifications?**

3     A66. Through the benchmarking study, and ad-hoc conversations, the Company found  
4     there is not an industry standard specification, however, there are common themes  
5     that all utilities focus on. Variation around trimming specifications is driven by  
6     variables, such as voltage, overhead equipment, tree density and species, and  
7     program funding.

8  
9     With respect to the proposed changes to the Company's specification, several  
10    observations can be made.

11           **1) Remove species-specific overhang** – a company's approach to  
12           trimming or removing overhang varies by program, with a wide  
13           spectrum of some utilities removing all overhang, and others only  
14           addressing flat-line, eminent risks. The variation in overhang treatment  
15           is driven by the different types of trees and location of the infrastructure  
16           relative to surrounding vegetation.

17           The Company's recommendation to expand the removal of overhang to  
18           include softwood species in Zones 2/3 is based on the unique  
19           characteristics of the Company's system. Over 80% of the tree work is  
20           in backlots, not along a roadway – this means the Company's  
21           infrastructure is more often surrounded by trees compared to a majority  
22           roadside system. Of the utilities benchmarked, DTE Electric had the  
23           highest percentage backlot, with the peer average being only 20%-30%  
24           backlot. In addition, DTE Electric's system has a 70% higher tree  
25           density (number of trees per mile) compared to peers. Therefore, the



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1 Company has more trees, closer to its equipment, compared to the  
2 Company's peers which justifies a unique, more aggressive approach to  
3 overhang removal.

4 **2) Improve the clearing of the "floor"** – it is common practice by other  
5 utilities to remove over 90% of the brush on their system. Currently the  
6 Company removes 50%-60% of the brush it touches. The proposed  
7 change for more aggressive brush removal will help align the  
8 Company's program with industry best practices.

9 **3) Establish an outside-the-right-of-way (OROW) Tree Risk Program**  
10 – based on industry expert feedback, best-in-class vegetation  
11 management programs spend 5%-10% of their annual budget on  
12 OROW tree removals along with mid-cycle inspections to ensure  
13 frequent assessment of emerging risks. The Company's current  
14 investment in OROW tree removals is less than 1%. The proposed  
15 changes would bring DTE Electric's investment in line with best-in-  
16 class and introduce a mid-cycle inspection.

17

18 **Q67. Do the specification changes align with external feedback received from the**  
19 **Liberty Audit and from Staff about the program?**

20 A67. Yes. The Liberty Audit noted similar opportunities for the Company to "[c]ontinue  
21 the current forestry methods and cycles, tuning and adjusting them as warranted by  
22 continuing evaluations of their costs and benefits and adjusting forecasted Tree  
23 Trimming expenditures as work continues into the next cycle(s)."<sup>9</sup>

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<sup>9</sup> Case No. U-21305; Liberty Audit, Part Two, pg. 69

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1 Specifically, the Audit stated, “DTE’s hazard tree removal practice comports with  
2 good utility practice” and “[t]he removal practice should continue until hazard trees  
3 no longer cause any subtransmission system outages and minimal distribution  
4 system outages.”<sup>10</sup> Additionally, the Liberty Audit appears to also provide support  
5 to improve clearing of the floor as well the Company’s plan to remove species-  
6 specific overhang. “The shortening of forestry cycles *and the enhancement of*  
7 *trimming and clearing methods* comprise core and highly effective elements of  
8 DGP plans for sustaining and *improving* reliability.”<sup>11</sup>

9 Lastly, there has been interest from the Staff for the Company to explore additional  
10 trimming related to overhang on distribution circuits. “Regarding DTE Electric’s  
11 proposal to perform more aggressive tree trimming in zones two and three, the Staff  
12 is in favor of the company comparing circuits trimmed during construction to  
13 determine whether zones two and three need more aggressive tree trimming.”<sup>12</sup>

14

15 **Q68. With respect to removing overhang, did the Company conduct analysis**  
16 **comparing the maintenance specification to the construction specification as**  
17 **proposed in Case No. U-21534?**

18 A68. As proposed, the Company attempted to perform a benefit-cost analysis of the  
19 maintenance specification where overhang is left on Zones 2 and 3 to the  
20 construction specification where the Company removes all overhang on the entire  
21 circuit. The Company completed preliminary analysis comparing circuits in  
22 geographic proximity that had been trimmed to the two different specifications.

---

<sup>10</sup> Case No. U-21305; Liberty Audit, Part Two, pg. 53

<sup>11</sup> Case No. U-21305; Liberty Audit, Part Two, pgs. 68-70

<sup>12</sup> Case No. U-21297 page 352-353, Case No. U-21534 page 224

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1 This analysis included comparing the cost of trimming and the post-trimming  
2 reliability.

3

4 **Q69. What were the conclusions from this analysis?**

5 A69. The Company found the preliminary analysis to be inconclusive on the incremental  
6 cost of removing overhang and as a result, difficult to quantify the reliability  
7 benefit. Each circuit has unique characteristics that drive the cost to improve  
8 reliability, making it difficult to isolate for a single variable, such as overhang.  
9 Further, the weather variability and limited years' worth of data with respect to  
10 circuits trimmed to the construction specification made it difficult to identify the  
11 reliability benefits specific to removing overhang compared to the ETPP  
12 specification.

13

14 **Q70. In light of the inconclusive cost-benefit analysis how did the Company develop**  
15 **its proposed changes to the treatment of overhang?**

16 A70. The Company opted for an alternative approach to determine the potential changes  
17 with respect to overhang by engaging with a third-party consultant with industry  
18 expertise in utility vegetation management. The consultant was Iapetus  
19 Infrastructure Services (IIS), who has over 100 years of experience in utility  
20 vegetation management and nationally-recognized thought leaders in this space.  
21 IIS conducted a holistic review of the Company's program and identified top  
22 priority areas for future expansion or changes.

23

24 Through this engagement, coupled with post-outage investigations and internal  
25 data, the recommendation to remove softwood overhang past the first protective

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1 device was identified. IIS specifically recommended, “continue ground-to-sky  
2 clearance in zone 1 to ensure maximum protection in high-risk areas. Adopt branch  
3 reduction strategies for zones 2 and 3.”<sup>13</sup> The data and pictures discussed above in  
4 Figures 1-3 support this recommendation.

5  
6 **Q71. Does the Company plan to change the specification in 2026?**

7 A71. The Company proposes to introduce these specification changes as part of its 2026  
8 maintenance program and maintain the ETP specification across the territory. The  
9 Surge has been a significant investment for the program and, at this time, the  
10 Company wants to maintain the current specification on the majority of the system  
11 and incorporate these changes on select circuits to collect data on the incremental  
12 costs and associated benefits. Further, these changes will require customer buy-in  
13 on additional removals. The Company has identified ways to increase customer  
14 approval around removals and will measure the effectiveness of different tactics to  
15 better understand how to successfully roll out the specification changes across the  
16 entire territory. If the specification changes prove to be beneficial, the Company  
17 may consider expanding the specification to include these changes for all miles  
18 trimmed in a future rate case proceeding.

19  
20 **Q72. What is the Company’s requested funding for 2026?**

21 A72. Based on maintaining the current ETP specification for the Company’s  
22 maintenance plan and introducing the potential specification changes, the Company  
23 is requesting \$180 million of O&M funding for 2026 as reflected in Exhibit A-13,

---

<sup>13</sup> Source third-party report commissioned by the Company by Iapetus Infrastructure Services

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1 Schedule C5.6.1, line 6. The \$180 million is split into two categories as shown  
2 below.

3

| Proposed 2026 O&M Tree Trim Budget |                      |
|------------------------------------|----------------------|
| Base Plan                          | \$145 million        |
| Specification Change Project       | \$35 million         |
| <b>Total</b>                       | <b>\$180 million</b> |

4

5 **Q73. What costs are included in the \$145 million for the Base Plan?**

6 A73. This funding will cover the execution of the maintenance plan for approximately  
7 6,000 miles (distribution and subtransmission) along with the supporting activities  
8 and functions (e.g., reactive trimming, herbicides, staffing, etc.). The 6,000 miles  
9 is based on the execution of the risk-based cycle model and shifting to an average  
10 cycle length of 5.6 years. The \$145 million will also cover the mid-cycle  
11 inspections and spot trimming addressed earlier in my testimony.

12

13 **Q74. What would the additional \$35 million cover?**

14 A74. The additional funding represents the incremental costs associated with executing  
15 the three aforementioned specification changes. These changes focus heavily on  
16 OROW inspections and removing trees and overhang branches, which is time-  
17 intensive and technical work. The funding will enable the Company to strategically  
18 implement these specification changes on certain circuits already on the  
19 maintenance plan. Therefore, the Company will be able to start introducing  
20 specification changes in pockets while maintaining the ETTP specification across  
21 the system.

Line  
No.

1     **Q75. What information and data will the Company collect as part of this project?**

2     A75. Along with the cost information, the Company will collect data on customer  
3           sentiment, contractor productivity, and reliability improvements.

4     **Q76. Why is it important to fund the specification project?**

5     A76. While the Tree Trim Surge has yielded significant benefit to customers, the  
6           specification change project provides the roadmap to expand the program to drive  
7           even further benefits. The Company recognizes the significant investment  
8           customers have made in the Tree Trim Surge and finds it prudent to introduce these  
9           changes on a selective basis prior to implementing system-wide. The project will  
10          enable important data collection and learnings such that the Company can better  
11          optimize a full-scale change in the specification in the future.

12

13     **Conclusion**

14     **Q77. Does the proposed 2026 funding and conclusion of the Surge align with**  
15           **Commission's directive in Case No. U-21534 Order on page 227?**

16     A77. Yes. It is planned that 2025 will be the final year of the Surge and that, upon the  
17           end of the Surge, tree trimming costs will revert to 100% O&M in 2026. The funds  
18           that are classified as a regulatory asset will be securitized in 2026 – further detail  
19           regarding tree trim securitization is contained in the testimonies of Witnesses  
20           Lepczyk and Uzenski.

21

22     **Q78. Does this complete your direct testimony?**

23     A78. Yes.

**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-21860

QUALIFICATIONS  
AND  
DIRECT TESTIMONY  
OF  
CHRISTOPHER J. HARTLEY

**DTE ELECTRIC COMPANY**  
**QUALIFICATIONS AND DIRECT TESTIMONY OF CHRISTOPHER J.**  
**HARTLEY**

Line  
No.

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

2   A1.   My name is Christopher J. Hartley (he/him/his). My business address is 8001  
3       Haggerty, Belleville, Michigan 48111. I am employed by DTE Electric Company  
4       (“DTE Electric” or the “Company”) as the Business Strategy and Support Manager  
5       for Community Lighting.

6

7   **Q2.   On whose behalf are you testifying?**

8   A2.   I am testifying on behalf of DTE Electric.

9

10   **Q3.   What is your educational background?**

11   A3.   I graduated from the University of Phoenix with a Bachelor of Science degree in  
12       Business Management in 2005.

13

14   **Q4.   What is your work experience?**

15   A4.   From 1996 to 1998, I served as a contractor for DTE Energy in the role of Lines  
16       Designer. My responsibilities included assessing customers' electrical needs and  
17       recommending suitable service methods. This role also involved preparing safe  
18       and cost-effective electrical designs and construction job packages.

19

20       In October 1998, I joined DTE Electric as an Associate Planner, where I performed  
21       similar tasks and was promoted to Planner – Planning & Design in 1999. In 2004,  
22       I advanced to the position of Planner Developmental Coordinator, where I took on  
23       additional managerial responsibilities.



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1 In 2007, I transitioned to the role of Principal Analyst at DTE Electric, supporting  
2 new business applications, analyzing system enhancement requests, and acting as  
3 a liaison between IT and business units. I held this position until 2012, when I  
4 became a Principal Supervisor within the Community Lighting group. In this role,  
5 I oversaw the Planning and Construction team and the Asset Management team,  
6 which managed the reliability and maintenance of outdoor lighting.

7

8 In 2018, I was promoted to Manager in Community Lighting, where I managed the  
9 Operations, Sales, and Business Development teams. Currently, I am the Manager  
10 of the Business Development and Support team.

11

12 **Q5. What are your current duties and responsibilities?**

13 A5. In my current role, I provide comprehensive business support to all areas within  
14 the Community Lighting team. This encompasses evaluating new products and  
15 services for potential market introduction to DTE Electric outdoor lighting  
16 customers. I also oversee billing functions for all outdoor lighting products across  
17 municipal, residential, and commercial accounts. Additionally, I manage the  
18 project execution of programs such as the front yard lamp post initiative, High-  
19 Intensity Discharge (HID) lighting conversions, and various preventative  
20 maintenance programs.

21

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

24 A6. No, I have not.

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1 **Purpose of Testimony**

2 **Q7. What is the purpose of your testimony?**

3 A7. The purpose of my testimony is to support the following topics related to DTE  
4 Electric's lighting assets: a) cost recovery of O&M and capital expenditures, and  
5 b) rate design. Specifically, I will discuss the following issues:

- 6 • Describe the portfolio of Community Lighting assets;
- 7 • Support the sales forecast for the various outdoor lighting rates including  
8 automated traffic signal (ATS) rates and metered street lighting rates;
- 9 • Describe the Company's preventative maintenance programs;
- 10 • Discuss the Company's outage restoration activities;
- 11 • Support and discuss Community Lighting's actual O&M expenses for the  
12 historical period which ended December 31, 2023, and the projected  
13 Community Lighting O&M expenses for the 12-month projected test period  
14 ending December 31, 2026;
- 15 • Support and discuss Community Lighting's actual capital expenditures for  
16 the historical period which ended December 31, 2023, and the projected  
17 Community Lighting capital expenditures for the 12-month projected test  
18 period ending December 31, 2026;
- 19 • Describe the Light-Emitting Diode (LED) luminaire selection methodology  
20 specific to HID to LED conversions;
- 21 • Support the proposed rate design for the outdoor lighting (municipal and  
22 other) and ATS tariff offerings using the lighting model.

23

24 **Q8. Are you sponsoring any exhibits in this proceeding?**

25 A8. Yes. I am sponsoring in whole, or in part, the following exhibits:

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| 1 | <u>Exhibit</u> | <u>Schedule</u> | <u>Description</u>                                  |
|---|----------------|-----------------|-----------------------------------------------------|
| 2 | A-12           | B5.5            | Projected Capital Expenditures – Community Lighting |
| 3 | A-13           | C5.6            | Projected Operation and Maintenance Expenses –      |
| 4 |                |                 | Distribution Expenses                               |
| 5 | A-16           | F3              | Present and Proposed Revenues by Rate Schedule – 12 |
| 6 |                |                 | months ending December 31, 2026                     |
| 7 | A-16           | F8              | Proposed Tariff Sheets                              |
| 8 | A-25           | O1              | Community Lighting Outdoor Lighting Outage Duration |
| 9 | A-25           | O2              | Community Lighting Outdoor Lighting Outage Cost     |

10

11 I am sponsoring line 23 within Exhibit A-13, Schedule C5.6, page 1 of 2, and the  
 12 pages specific to the residential and commercial outdoor protective lighting (OPL)  
 13 and municipal classes within Exhibit A-16, Schedule F3. This includes pages 46  
 14 through 57. On Exhibit A-16, Schedule F8, I sponsor the OPL and municipal  
 15 tariffs, while Company Witness Turner will sponsor the tariff for the E1.1 rate.

16

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

18 A9. Yes, they were.

19

## 20 **Community Lighting Assets**

21 **Q10. Could you describe the portfolio of Community Lighting assets that DTE**  
 22 **Electric owns, operates, and maintains on behalf of its customers?**

23 A10. Yes. DTE Electric owns, operates, and maintains approximately 200,000  
 24 Community Lighting assets which serve municipal, commercial, and residential  
 25 customers. Additionally, there are approximately 82,000 streetlights which are

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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 based upon known asset counts as of July 1<sup>st</sup>, 2024:

**Table 1: Community Lighting Assets**

| Asset Type                                | Asset Ownership | Rate Type     | # of Assets | Description                                          |
|-------------------------------------------|-----------------|---------------|-------------|------------------------------------------------------|
| Municipal OH &UG Street Lights            | DTE Electric    | E1 Option I   | 166,782     | DTE Electric owned and maintained system             |
| Municipal OH &UG Street Lights            | Customer        | E1 Option II  | 84          | Municipal owned and DTE Electric maintained system   |
| Municipal OH &UG Street Lights            | Customer        | E1 Option III | 82,518      | Municipal owned and maintained system                |
| Commercial Outdoor Protective Lights      | DTE Electric    | D9            | 24,713      | DTE Electric owned and maintained lighting equipment |
| Residential Outdoor Protective Lights     | DTE Electric    | D9            | 9,132       | DTE Electric owned and maintained lighting equipment |
| Municipal Automated Traffic Signals (ATS) | Customer        | E2            | 6,451       | Municipal owned and maintained equipment             |

**Q11. What are the various lighting technologies in service, and how is DTE Electric transitioning to more energy-efficient Company-owned LED lighting technology?**

**A11.** There are four lighting types currently in use within DTE Electric's service territory: Light Emitting Diode (LED), High Pressure Sodium (HPS), Metal

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1 Halide (MH), and Mercury Vapor (MV). LED lighting is the most energy efficient  
2 lighting type available, while the remaining light types are less efficient in terms  
3 of energy consumption (MV is the least efficient of the 4 light types). LED  
4 lighting is the only technology that DTE offers for new lighting requests.

5

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

14

15 The Company has worked closely with its municipal partners, commercial and  
16 residential customers over the past decade as they transition to LEDs as a preferred  
17 lighting technology. In 2022, the Southeast Michigan Council of Governments  
18 (SEMCOG) made available grant funding for several types of carbon reduction  
19 initiatives, which included municipal lighting conversions to LEDs. DTE made  
20 communities aware and assisted several communities to complete their  
21 applications. In 2023, almost \$3.4 million in grant funds were awarded to several  
22 DTE municipal customers to help fund HID to LED conversion projects totaling  
23 approximately 11,000 lights anticipated to be installed between 2024 – 2025. Table  
24 2 below provides a snapshot of the changes over time in DTE Electric's company  
25 owned lights, from 2012 to 2024:

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1 **Table 2: Community Lighting Assets by Lighting Type (2012-2024)<sup>1</sup>**

| Lighting Type              | 2012         | 2017         | 2024          |
|----------------------------|--------------|--------------|---------------|
| Light Emitting Diode (LED) | 2,851 (1%)   | 53,018 (27%) | 132,112 (66%) |
| High Pressure Sodium (HPS) | 98,070 (49%) | 91,422 (46%) | 50,061 (25%)  |
| Mercury Vapor (MV)         | 94,681 (48%) | 52,518 (26%) | 16,969 (9%)   |
| Metal Halide (MH)          | 2,977 (2%)   | 2,468 (1%)   | 1,485 (1%)    |
| Total Assets               | 198,579      | 199,426      | 200,627       |

2

3 **Q12. Can you provide an overview of the various lighting technologies employed**  
4 **within DTE Electric's Municipal Street Lighting Business, E1 Option I?**

5 A12. Yes. The current lighting portfolio for street lighting customers served on DTE  
6 Electric's E1 Option I Rate Schedule referenced in Table 1 above, includes  
7 approximately 166,000 total Company owned lights as of July 1<sup>st</sup>, 2024. Table 3  
8 below shows the breakout of lighting types by total count and percentage:

9

10 **Table 3: E1 Option I Light Counts by Type**

| Lighting Type              | Asset Count | % of Total Assets |
|----------------------------|-------------|-------------------|
| Light Emitting Diode (LED) | 119,717     | 72%               |
| High Pressure Sodium (HPS) | 37,541      | 23%               |
| Mercury Vapor (MV)         | 8,209       | 5%                |
| Metal Halide (MH)          | 1,315       | 1%                |
| Total E1 Option I Assets   | 166,782     | 100%              |

11

12 While the quantity of high-pressure sodium and mercury vapor luminaires has been  
13 steadily dropping over the past several years, the total number of LED luminaires  
14 continues to increase in-kind due primarily to municipal driven conversions and  
15 outage restoration luminaire replacements. Metal halide lighting luminaires  
16 represent approximately 1,300, or less than 1% of DTE Electric's company owned

---

<sup>1</sup> Light counts as of July 1<sup>st</sup>, 2024.

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1 lighting luminaires. As noted earlier, more than 20% of the remaining non-LED  
2 municipal streetlights are targeted for conversion to LED because of the recently  
3 awarded SEMCOG project grants.

4

5 **Q13. What are the various lighting technologies for municipality owned (E1 Options**  
6 **II & III) streetlights?**

7 A13. The lighting for DTE Electric's E1 Option II Rate Schedule reflects a mix of high-  
8 pressure sodium lights and mercury vapor lights. As previously indicated, this  
9 service has been closed to new customers since 2009, and existing E1 Option II  
10 Rate Schedule customers electing to convert to LED are required to convert to  
11 DTE Electric's E1 Option I or Option III Rate Schedules. The mix of lighting for  
12 DTE Electric's E1 Option III Rate Schedule includes approximately 70,000 (84%)  
13 LED luminaires, 12,000 (15%) high pressure sodium luminaires, and the  
14 remainder consisting of MV and MH lighting. The high concentration of energy-  
15 efficient LED lighting in this class reflects the City of Detroit's conversion of most  
16 of its streetlights to LED.

17

18 **Q14. Can you provide an overview of DTE Electric's Community Lighting D9 OPL,**  
19 **E2 ATS, and E1.1 metered municipal-owned lights rate schedules?**

20 A14. Yes. DTE Electric's D9 OPL rate schedule and its proposed pricing reflect  
21 recovery of costs associated with the ownership, maintenance, and provision of  
22 energy to a portfolio of approximately 24,000 commercial and 9,000 residential  
23 outdoor protective lights. OPL lighting uses the same technologies as  
24 streetlighting and, consistent with conversions of failed mercury vapor streetlights

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1 to LED, the Company began converting failed mercury vapor OPLs to LED  
2 starting in February 2017.

3  
4 DTE Electric's E2 Rate Schedule and proposed pricing reflect the recovery of costs  
5 for the production and distribution of energy for automated traffic signal (ATS)  
6 lights owned and maintained by municipalities and other public authorities.  
7 DTE Electric also provides metered, municipal-owned streetlight service under the  
8 E1.1 Rate Schedule. I support the energy forecast for this Rate Schedule and  
9 Witness Turner supports the proposed rate for this service.

10

11 **Q15. Are you proposing any changes to the E1 Option I and D9 tariff language?**

12 A15. Yes. We are proposing to include the following language for both E1 Option I and  
13 D9 tariff options:

14

15 "Effective January 1<sup>st</sup>, 2025, new high-pressure sodium (HPS) fixtures will no  
16 longer be available. Customers with existing HPS fixtures will continue to receive  
17 service until those fixtures fail. At that time, the fixture will be converted to an  
18 LED luminaire."

19

20 The company proposes adding this language following the paragraph that  
21 references "The Energy Policy Act of 2005" on pages D-50.02 and D-52.00 of the  
22 E1 Tariff and on pages D-45.02 and D-46.01 of the D9 Tariff.

23

24 We also propose deleting the reference to "furnishing lamp replacements" noted  
25 within the Option I paragraph under "Kind of Service", located on page D-49 of



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1 the E1 Tariff, as the company is no longer servicing HID luminaires and is opting  
2 to replace with new LED luminaires.

3  
4 Specific to the D9 tariff on page D-44.00, the company recommends modifying the  
5 “Availability of Service” section to read as follows: “Customers desiring controlled  
6 service for outdoor protective lighting. The customer must have an active electric  
7 service under a standard metered rate schedule. The lighting can be installed at the  
8 premise location that is associated with the metered account or may also be installed  
9 at any alternate location that has a designated physical address.”

10

11 **Q16. Are you proposing changes to the D9 or E1 rate schedules?**

12 A16. Yes. The Company is proposing to add a new wattage category within the D9  
13 section of the tariff specific to the Outdoor Protective Lighting service. The new  
14 wattage range to be added will be the 10 – 19-Watt LED classification for  
15 underground fed lighting options.

16

17 **Q17. Why is the Company proposing to add this new wattage classification to the**  
18 **D9 tariff?**

19 A17. The Company has received multiple customer requests related to providing bollard  
20 style lighting, which is not currently a product that the company offers or maintains  
21 inventory for. These bollard style lights are primarily used for pedestrian  
22 walkways and provide illumination through low wattage LED lights that are  
23 mounted at the top of the post, which is typically no taller than 48 inches high. The  
24 typical wattage range for the LED light within bollard may vary from 10 watts at  
25 the lower end to 29 watts at the higher end.

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1 An image of a lighting bollard product is provided in Figure 1 for illustrative  
2 purposes.

3 **Figure 1 Bollard Light**



4

5 **Community Lighting Sales Forecast**

6 **Q18. How did you develop the Lighting sales forecast for E1 Options I & II?**

7 A18. Consistent with the methodology utilized in prior Company electric rate cases, the  
8 sales forecast for the E1 Option I & II Rate Schedules were developed by first  
9 preparing a forecast of light counts for each lighting type (technology and wattage  
10 size) for the projected test period based upon: (1) known projects, (2) continued  
11 conversions of mercury vapor lighting to LED lighting, and (3) an estimate of  
12 increased light counts net of removals, resulting from sales growth. The system  
13 wattage (nominal lamp wattage plus ballast wattage) applicable to each lighting  
14 type was applied to the forecasted volume of lights for each lighting type. Annual  
15 usage was assumed to be 4,200 hours, to reflect the hours that the lights on either  
16 the dusk to dawn or standard provision are illuminated. The energy forecast for  
17 lights on the dusk to midnight provision was based upon 2,100 hours use and the  
18 energy forecast for lights on the de-energized provision is zero. Lastly, the lighting  
19 sales forecast for the E1 Option 1 class was reduced by 4.06% in this case, based

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1 on previous night patrol outage results. This adjustment was made in accordance  
2 with the Michigan Public Service Commission (MPSC) Order on page 190 in Case  
3 No. U-21297, which instructed the Company to modify the lighting sales forecast  
4 to account for outages and prevent customers from being charged for unused  
5 electricity. This methodology is also consistent with the calculation of tariffs  
6 approved by the Commission in their Order in Case No. U-21534.

7

8 **Q19. How did you develop the Lighting sales forecast for E1 Option III, D9, E2, and**  
9 **E1.1?**

10 A19. The sales forecast for the E1 Option III Rate Schedule was developed by first  
11 preparing a forecast of light counts for each of the lighting types for the projected  
12 test period based upon known municipal-owned streetlighting projects and an  
13 estimate of light count changes. The system wattage value applicable to each  
14 lighting type was applied to the forecasted volume of lights for each lighting type  
15 for the 4,200 hours for which all the lights are illuminated on an annual basis.

16

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

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1 The sales forecast for the E2 ATS Rate Schedule was determined by using the total  
2 connected wattage, as of July 2024, for the rate schedule and determining the annual  
3 usage based upon that determinant. In other words, it is simply the product of the  
4 total reported wattage and the total number of hours in the projected test period.

5

6 The total sales forecast for the E1.1 Rate Schedule was based upon annualized  
7 usage data for the 12-month period that ended July 2024.

8

9 **Company Preventative Maintenance Programs**

10 **Q20. What preventative maintenance programs does the Company manage, and**  
11 **how are the associated costs of these programs classified?**

12 A20. The Company manages the following preventative maintenance programs: 1) Post  
13 Inspections, 2) Post Painting, 3) Night Patrol, 4) Post Replacement, and 5) Cable  
14 Replacement. The Post and Cable Replacement programs are considered capital  
15 expenditures while the remaining programs are classified as O&M.

16

17 **Q21. What is the Company's Post Inspection program and how does it relate to the**  
18 **Post Painting and Post Replacement programs?**

19 A21. DTE Electric owns a combination of more than 60,000 decorative metal or  
20 fiberglass posts and has established detailed post inspection criteria to inspect its  
21 posts every three years to both identify posts whose structural integrity dictates  
22 their replacement (condemnation), and posts that require painting. Annually this  
23 typically amounts to about 20,000 post inspections per year. At the time posts are  
24 inspected, minor post maintenance work such as adding or replacing post asset  
25 tags, post hand-hole covers, and T-box door covers may also be completed. Over

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1 the past three years, DTE Electric's decorative post inspection process has resulted  
2 in the annual replacement of condemned posts at a rate of approximately 3% and  
3 post painting at a rate of approximately 2% relative to the total population of posts.

4  
5 **Q22. How much does the Company plan to invest in the Post Inspection and Post**  
6 **Painting programs during 2025?**

7 A22. The company has allocated approximately \$165,000 for Post Inspections and  
8 approximately \$250,000 for Post Painting. These preventative maintenance  
9 programs are essential as they enable the company to identify defects on a regular  
10 basis. The Post Inspection program allows the company to detect posts in the field  
11 with defects and to proactively replace these assets promptly, thereby preventing  
12 any safety-related hazards. The Post Painting program ensures the maintenance of  
13 the aesthetic properties of the post assets.

14  
15 **Q23. Does the Company also inspect its streetlight-only wood poles?**

16 A23. Yes. Our streetlight-only wood poles are inspected as part of DTE Electric's Pole  
17 Top Maintenance and Modernization program (PTMM) managed by Distribution  
18 Operations. As wood poles are inspected through this program, streetlight-only  
19 wood poles identified as condemned or near end-of-life, are sent to DTE Electric  
20 – Community Lighting for replacement by its contractor(s) responsible for  
21 replacing our decorative metal posts.

22  
23 **Q24. What is the purpose of the Company's Night Patrol program?**

24 A24. The purpose of DTE Electric's Night Patrol program, implemented in 2019, is to  
25 proactively identify municipal-wide outages and route them to a DTE Electric

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1 authorized construction crew for repair. This initiative aims to bolster customer  
2 service and reliability by identifying outages before they are reported by the  
3 public, thereby reducing the non-working time of streetlights.

4

5 **Q25. How does the Night Patrol program achieve its objectives?**

6 A25. The Night Patrol program proactively inspects all DTE Electric's E1 Option I  
7 streetlights. As shown in Exhibit A-25, Schedule O1, DTE Electric has proactively  
8 patrolled over 800,000 lights over the past five years. Patrol schedules are dynamic  
9 and adaptable, adjusted based on prior patrol results and repair details, (i.e. large  
10 percentage of outages noted in a single municipality or high concentration of  
11 outages in a specific area).

12 **Q26. What impact has the Night Patrol program had on community lighting**  
13 **reliability?**

14 A26. The Night Patrol program has significantly improved community lighting  
15 reliability through proactive maintenance, data-driven improvements, and targeted  
16 responses. By identifying outages before public reporting, the program reduces the  
17 duration of non-working lights, enhancing overall service reliability. Although  
18 managed outside the new outage management system (OMS), the program gathers  
19 valuable data attributes about outages, which helps the Company determine areas  
20 for targeted capital investments. Additionally, the program has improved  
21 reliability by identifying communities with higher outage rates and providing them  
22 with more frequent patrol and repair opportunities, ensuring resources are  
23 allocated where they are needed most.

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1 **Q27. What is the Company's Cable Replacement program?**

2 A27. In general, outages are the result of 1) a failed luminaire, 2) failed wiring or  
3 components such as a photocell, or 3) failed underground cable. These outages  
4 may occur randomly over the course of time as the system ages or may also be the  
5 result of 3<sup>rd</sup> party damages.

6  
7 The cable replacement program is a key capital-based initiative to address failed  
8 underground cables. Geographically speaking, the company has over 1,500 miles  
9 of underground cable infrastructure which provides electrical connection to over  
10 60,000 underground fed streetlights. There are areas within the system where direct  
11 buried cable exists and when these sections are detected through any variety of  
12 maintenance repair or third-party damage repairs, it is prudent and cost effective to  
13 replace the cable with new conductor installed within a protective conduit. This  
14 program specifically targets underground cable replacement work as this tends to  
15 be the costliest type of repair to perform on a reactive basis and has a higher  
16 likelihood to impact multiple lights when the cable begins to fail. Repairing larger  
17 stretches of cable using a data driven approach on a planned basis through this  
18 program is not only more cost effective but is also anticipated to reduce the  
19 likelihood of one or more lights failing due to an underground fault once replaced,  
20 thereby increasing reliability.

21

22 **Q28. Do you have an example that demonstrates the effectiveness of the cable**  
23 **replacement program?**

24 A28. Yes. In 2023, the Company replaced approximately 70,000 feet of underground  
25 cable related to 20 different circuits. Prior to the cable replacement, there was a

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1 total of 80 unique outage events related to these underground circuits. Following  
2 the cable replacement completions, when reviewing the 2024 performance of these  
3 circuits, there were 10 related outage events across these 20 circuits, but only 1  
4 event was related to an underground issue where a locate and repair activity needed  
5 to be completed. Additionally, in 2024, the Company replaced approximately  
6 80,000 feet of cable related to 21 unique underground circuits, and the Company  
7 will monitor the reliability of these circuits throughout 2025 to ensure that  
8 reliability improvements are realized.

9

10 **Q29. How is proactive underground cable replacement work more cost effective**  
11 **than reactive repairs?**

12 A29. When responding to outage events that involve underground cable failures as the  
13 root cause, our repair crew's primary objective is to address the immediate issue  
14 and restore service as quickly as possible. This increases the number of "locate  
15 and repairs" which results in sections of failed cable being isolated and replaced.  
16 Though this addresses the immediate root cause, it doesn't necessarily increase the  
17 longevity of the stretch of cable supporting that circuit, in a manner that replacing  
18 failed, or end-of-life underground cable would. Proactive cable replacement  
19 through planned capital work allows the company to benefit from competitive unit  
20 pricing, making these projects cost-effective. Essentially the company is able to  
21 take advantage of better replacement per foot costs with larger projects that can be  
22 planned ahead as opposed to reactive outage repairs. Data collected at the circuit  
23 level post-project completion shows improved reliability for the circuits with  
24 replaced cables, providing solid evidence of the positive impact.



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1   **Q30. How is the newly implemented OMS supporting the cable replacement**  
2       **program?**

3   A30. The newly implemented OMS allows improved data gathering related to outage  
4       repairs and the associated root cause. When the root cause has been determined to  
5       be underground related, the specific underground circuit is also being identified as  
6       a data attribute. This now allows the outage analyst to identify recurring outage  
7       themes related to specific circuits, which then allows for future underground cable  
8       testing, and the potential for cable replacement.

9

10   **Q31. Are there any other long-term benefits expected to be realized from the Cable**  
11       **Replacement program?**

12   A31. Yes. There are still significant portions of the underground system that are directly  
13       buried at depths usually less than 24 inches, which makes them more susceptible  
14       to freezing and thawing impacts, as well as 3<sup>rd</sup> party strikes during excavation work  
15       (i.e., other utility work, municipal driven projects such as road widenings, or even  
16       driveway replacements). The Company has regularly utilized conduit during the  
17       installation of new lighting projects and during maintenance repairs for a number  
18       of years but lacked a formal cable replacement program until 2022. Cable replaced  
19       under this program are now installed within a protective conduit, increasing the  
20       likelihood that it can survive a 3rd-party strike or exposure through excavation.  
21       Performing cable replacement as a capital driven program allows the Company to  
22       identify larger scopes of work that create cost efficiencies related to contractor  
23       pricing. Over time, this will reduce the number of reactive underground cable  
24       events and increase lighting system reliability to the benefit of customers.

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1   **Q32. Do you anticipate any changes in funding for the cable replacement program**  
2       **through the projected test year period?**

3   A32. Yes. The Company plans to spend \$2 million in 2025 and an additional \$2 million  
4       in 2026. Through prior year data, the Company has identified approximately  
5       50,000 feet of cable to be replaced across several underground circuits in 2025.  
6       Additional circuits will continue to be identified and evaluated throughout the year  
7       and added to the cable replacement plan. The circuit selection process for cable  
8       replacement will continue to be based on data driven results from the OMS where  
9       the circuits with the poorest reliability, in addition to other evaluation scoring, will  
10      be prioritized and addressed in a timely manner.

11

12   **Outage Restoration Activities**

13   **Q33. What was DTE Electric's performance with respect to outage duration for its**  
14       **lighting customers?**

15   A33. DTE Electric's 2024 outage duration performance was approximately 4.6 days.  
16       Exhibit A-25, Schedule O1 provides a detailed summary of outage reliability and  
17       performance metrics from 2018 to 2024. Night patrol results are also included  
18       within this exhibit and identify the number of lights patrolled, number of  
19       corresponding outage repairs, and the associated percentage of lights found to be  
20       non-operational.

21

22   **Q34. What other measures does DTE Electric have in place to improve its outage**  
23       **restoration time and to maintain focus on customer service for lighting**  
24       **customers?**

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1 A34. Restoration performance, among other metrics, is reviewed with our contractors  
2 at monthly performance meetings. To the extent that restoration performance is  
3 not meeting expectations, DTE Electric can shift restoration work as needed to  
4 alternate contractors to achieve the desired restoration performance. Internally,  
5 the Company evaluates contractor performance metrics weekly to identify  
6 potential performance issues or problem-solving opportunities. Additionally, the  
7 Company collaborates with municipal customers who previously chose special  
8 order materials (SOM) due to a lack of suitable options. As DTE Electric's material  
9 offerings have expanded, municipalities now have the opportunity to switch back  
10 to DTE Electric standard stock, reducing outage durations caused by unavailable  
11 repair materials.

12

13 **Q35. Could you please summarize DTE Electric's outage performance for lighting**  
14 **customers over the past five years?**

15 A35. While any individual year will be impacted by external factors such as changing  
16 weather patterns (i.e. more freezing, thawing leads to increased cable faults, etc.)  
17 and number of catastrophic storms (i.e. construction crews being diverted to assist  
18 in power restoration activities, etc.), key outage metrics continue to be dependable  
19 and consistent. Over the prior 5 years, between 2020 and 2024, the average outage  
20 duration has been 4.39 days. When factoring in the longer duration follow up  
21 events over that same period, the average duration has been 6.4 days, and the total  
22 days duration of 6.2 days in 2024 was lower than the 5-year average. Typical  
23 factors that cause an outage event to be put into the long-duration follow up  
24 category include, but not limited to: 3<sup>rd</sup> party damages, permit requirements,

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1 special order materials required to be supplied by the municipality, tree trim  
2 requirements, etc.

3

4 **Q36. Why has the total number of outage events increased in 2024?**

5 A36. The Company's new OMS system, KloudGin, now has the ability to track the  
6 number of individual lights out by event, which was not possible with our previous  
7 OMS system. Outage data in the prior OMS system counted the number of events,  
8 which could be one light per event or many lights per event. Using the new OMS  
9 system, a unique outage event is created for every light reported out. The Company  
10 now has expanded functionality by providing customers with the ability to use a  
11 graphical user interface map to click on the specific lights that are out. This system  
12 continues to be refined as the Company receives continuous improvement  
13 feedback from lighting contractors making lighting repairs. For example,  
14 additional root causes have been implemented so outage events can be better  
15 classified to create greater transparency in the reporting of metrics. When fully  
16 refined, the new OMS will be able to report the total number of lights affected by  
17 all outage events created in the system.

18

19 **Q37. Has the company started creating outage reliability reports that can be shared**  
20 **with their municipal customers?**

21 A37. Yes. Outage reports with details from the new OMS were distributed to all of the  
22 municipalities that opted in to receive these reports. The reports include 1)  
23 customer reported outage events, 2) average outage duration for all customer  
24 reported outage events, and 3) counts of outages lasting longer than 14 days, and

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1 4) counts of outage detected from the night patrol program. These reports were  
2 issued in February 2025.

3

4 **Q38. What is the status of the new OMS system?**

5 A38. The new OMS was fully integrated and functional since 2024 but also has been  
6 continually refined throughout the year to address various usability issues and to  
7 incorporate improvements to help with data management. As of fourth quarter of  
8 2024, the OMS is fully functional and able to capture customer reported outages  
9 and contains automation that allows for direct assignment of outage events to  
10 streetlighting repair contractors and is capable of generating the required outage  
11 duration data that is needed to support business unit metrics. The Company  
12 continues to work with the software vendor to identify available enhancements,  
13 such as material management solutions, that are targeted for second quarter of  
14 2025 implementation.

15

16 **Q39. What was Community Lighting's spend with respect to outage restoration**  
17 **activity in 2024?**

18 A39. The spend for 2024 was approximately \$9.9 million. Exhibit A-25, Schedule O2  
19 reflects DTE Electric's historical performance for outage restoration cost per  
20 event. The 2024 costs experienced an approximate 28 percent increase from the  
21 prior year. A contributing factor to this increased spend was due to the Company  
22 replacing over 2,000 more lighting fixtures during outages than in the prior year.

23

24 **Q40. Why was there an increase in lighting fixtures being replaced?**

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1 A40. Heading into the 2024 year, the Company was notified by various HID lighting  
2 manufacturers that they were no longer supporting or producing those products.  
3 Therefore, the Company decided to stop maintaining HID luminaires but instead  
4 replace the failed HID luminaire with the same type of HID fixture to exhaust  
5 inventory. When HID inventory is exhausted, the Company plans to replace failed  
6 HID luminaires with LED moving forward.

7  
8 **Q41. What is the difference between capitalized outage expenses and non-**  
9 **capitalized, or O&M outage expenses?**

10 A41. Outage restoration activities include remediating identified lighting outages that  
11 could range from replacement of small wiring or lighting components to  
12 replacement of system cable, posts, and luminaires. Any repair (inclusive of both  
13 materials and labor) that does not extend the useful life of the lighting asset (small  
14 wiring or lighting components such as a replacement of a fuse) is considered an  
15 O&M expense. All other repairs (both materials and labor) are considered capital  
16 expenditures.

17

18 **Community Lighting Operations & Maintenance and Capital Expenditures**

19 **Q42. What is included in the Operations & Maintenance of Street Lighting and**  
20 **Signal Systems account on line 23 of Exhibit A-13, Schedule C5.6, page 1?**

21 A42. Line 23 on this exhibit shows the projected O&M expenses which are directly  
22 assigned to Account 596, Maintenance of Street Lighting and Signal Systems.  
23 This account represents preventive maintenance expense, labor expense and non-  
24 capitalized outage restoration expense. The preventive maintenance work  
25 includes post inspection, post painting, and night patrols for DTE Electric owned

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1           municipal streetlights. The labor expense primarily reflects the labor of the  
2           Community Lighting team including sales, planning, asset maintenance,  
3           construction, and asset engineering. As reflected on Exhibit A-13, Schedule C5.6,  
4           the historical period O&M expense of \$3.4 million is adjusted first for  
5           normalization attributable to an anticipated increase in O&M related outage spend  
6           of \$0.4 million, and then for inflation of 3.4% for 2024, 3% for 2025, and 3.1%  
7           for 2026. This results in a forecasted O&M expense of \$4.6 million in the projected  
8           test period.

9

10   **Q43. What are the Community Lighting capital expenditures on Exhibit A-12,**  
11   **Schedule B5.5, “Projected Capital Expenditures – Community Lighting”?**

12   A43. Capital expenditures for Community Lighting for 2023 were approximately \$18.3  
13   million. The 2023 expenditures included approximately \$8.9 million for new  
14   installations and replacements, \$7.1 million for outage restoration, \$1.6 million for  
15   cable replacement, \$0.3 million for post replacements, and \$0.3 million for HID  
16   to LED conversions.

17

18           The capital expenditures for Community Lighting were \$27 million for 2024 and  
19           projected \$17.7 million for 12 months ending December 31, 2025, and \$17.7  
20           million for 12 months ending December 31, 2026. Similar to the 2024 actual  
21           expenditures, these projections include new installations and replacements, outage  
22           restoration, which includes replacement of failed mercury vapor and high-pressure  
23           sodium luminaires to LED for both streetlight and OPLs, post replacement, cable  
24           replacement, and HID to LED conversions.

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1 **LED Conversions Technical Workshop and Early LED Adopter Bill Credits**

2 **Q44. Can you summarize the Commission's findings and directives in their order**  
3 **in Case No. U-21534 regarding DTE's luminaire selection methodology?**

4 A44. On page 169 of their January 23, 2025 order in Case No. U-21534, the MPSC  
5 Commission stated that while "DTE Electric in this case adequately demonstrated  
6 that the company's LED choices met FHA standards, the Commission remains  
7 convinced that there is still ample room for improvement in the company's  
8 streetlighting program, including a closer nexus with the maintained lighting levels  
9 of the FHA handbook, as well as relevant ANSI/IES standards that have been the  
10 basis of much of the disputes between DTE Electric and MI-MAUI in the past  
11 several rate cases." Consequently, the Commission directed Staff to conduct a  
12 technical workshop with DTE Electric, MI-MAUI, relevant roadway luminaire  
13 manufacturers, vendors, engineers, Consumers Electric, and other interested  
14 parties. The first meeting for this workshop is tentatively scheduled for May 19,  
15 2025.

16

17 **Q45. Can you summarize the Commission's requirements in Case No. U-21534**  
18 **regarding bill credits for early adopters of LED luminaire technology, and the**  
19 **Company's actions to comply with this directive?**

20 A45. The Commission stated on page 436 of their order in Case No. U-21534, "[t]he  
21 Commission finds that, similar to the LED conversion credit approved in Case No.  
22 U-21389 for Consumers, DTE Electric should adopt a time-limited bill credit per  
23 each LED light per year which is adjusted as new rates incorporate changes." The  
24 Company is working on calculating a proposed bill credit and intends to meet with



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1 Staff and other interested parties prior to filing for approval of the credit later this  
2 year.

3

4 **Community Lighting Rate Design**

5 **Q46. What does Exhibit A-16, Schedule F3 show?**

6 A46. This exhibit shows the present and proposed rate design and corresponding  
7 revenues by rate schedule, based on the billing determinants for the 12 months  
8 ending December 31, 2026. The exhibit details the forecasted billing determinants  
9 as well as the resulting present and proposed rates and revenues. The various  
10 billing components are listed in column (a), and the respective billing  
11 determinants, including units of measure, are listed in column (b). The forecasted  
12 billing determinants were developed based on historical data and relationships, as  
13 well as known and measurable changes, and are consistent with the sales forecast  
14 as presented on Company Witness Mr. Leuker's Exhibit A-15, Schedule E1, Other  
15 class sales. The existing luminaire and energy rates, both non-capacity energy and  
16 capacity energy, as approved in the Order dated January 23, 2025, in Case No. U-  
17 21534 are in columns (c), (d) and (e), and are used to calculate the present revenues  
18 in column (f). The luminaire rates proposed in this proceeding based upon the  
19 lighting cost of service (as discussed in detail below) are in column (g), the  
20 proposed non-capacity energy rates are in column (h), the proposed capacity  
21 energy rates are in column (i) and the resulting revenues from the new lighting  
22 cost of service are in column (j).

23

24 **Q47. How were DTE Electric's present Municipal Street Lighting and Outdoor**  
25 **Protective Lighting charges determined?**

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1 A47. The lighting rates approved in MPSC Case No. U-21534 reflect a monthly energy  
2 charge, both non-capacity energy and capacity energy, and a luminaire charge.  
3 The monthly energy charge was determined by applying the energy rates, both in  
4 cent/kWh, to the calculated consumption values of the various lighting technology  
5 lamp sizes for both the E1 and D9 Rate Schedules. The luminaire charge is a fixed  
6 monthly amount applied to each luminaire dependent on the technology utilized,  
7 the lamp size or wattage, the lighting provision and whether it is served from  
8 underground or overhead. The total (energy and luminaire) monthly lighting  
9 charges that were calculated in Case No. U-21534 do not fully represent true cost  
10 of service rates by technology type (within the lighting rate class). In Case No. U-  
11 21534, the lighting rates were gradually moved towards cost of service, with the  
12 total movement capped to minimize the impact on any individual municipal  
13 customer.

14

15 **Q48. What is the allocation methodology for production and distribution revenue**  
16 **requirements to the various lighting rate schedules that you are supporting in**  
17 **this case?**

18 A48. The functionalized production (Exhibit A-16, Schedule F1.1) and distribution  
19 (Exhibit A-16, Schedule F1.2) revenue requirement amounts supported by  
20 Company Witness Cejas Goyanes for each of the lighting rates schedules (D9, E1,  
21 & E2) were fully allocated to each of those rate schedules within the lighting rate  
22 model. The proposed luminaire, distribution, and energy charges (both capacity  
23 and non-capacity) within each of the rate schedules were designed to meet the  
24 production and distribution revenue requirement for each rate schedule shown in  
25 these exhibits. Witness Cejas Goyanes' Exhibit A-16, Schedule F1.5, detailing

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1           how much of the production revenue requirement for each rate class is capacity  
2           and non-capacity related, was used to allocate the production revenue requirement  
3           between the capacity and non-capacity energy charges. E1 Option I non capacity  
4           rate is reduced by 4.06% to lower energy charge due to outage identified through  
5           night patrol as mentioned above.

6

7       **Rate Schedule E1**

8       **Q49. How were the proposed E1 Rate Schedule luminaire charges determined?**

9       A49. The Company determined the new luminaire service cost structures listed in the  
10       E1 Rate Schedule tariff schedules as shown on Exhibit A-16, Schedule F3 by  
11       reviewing and allocating the specific cost of service components to the type of  
12       service, underground or overhead, and then further allocating them to the  
13       individual lighting technologies. There were no changes in the methodology for  
14       the allocation of non-production O&M costs or capital-related costs to luminaire  
15       charges proposed in this proceeding.

16

17       **Q50. How was O&M allocated to the proposed E1 Rate Schedule luminaire charges**  
18       **in the lighting model?**

19       A50. Total Distribution O&M expense reflected in the E1 Rate Schedule luminaire  
20       charge is \$11 million, based upon the Company's cost of service model sponsored  
21       by Witness Cejas Goyanes. This distribution O&M expense is comprised of \$3.6  
22       million directly assigned to lighting and recorded in account 596 (Street Lights &  
23       OPL), \$4.5 million is allocated to lighting from various distribution operations and  
24       distribution maintenance accounts, \$1.2 million from various customer  
25       service/sales accounts allocated to E1 Rate Schedule lighting and \$1.7 million of

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1 total A&G expense. Based upon the underlying labor costs within account 596  
2 and the various distribution operation, distribution maintenance and customer  
3 service accounts allocated to E1 Rate Schedule lighting, approximately 41%, or  
4 \$0.7 million, of A&G expense was directly allocated to E1 Option I Rate Schedule  
5 lighting and the balance was allocated to the various distribution O&M accounts  
6 within the E1 Rate Schedule.

7

8 The total customer service and distribution O&M expense allocated to lighting,  
9 including A&G allocated to these accounts, was further allocated to the various E1  
10 Rate Schedule luminaire/distribution charges based upon the system wattage of the  
11 luminaires and lamps. With the exception of post inspection, night patrols and post  
12 painting, all O&M (\$3.6 million) and A&G (\$.7 million) directly assigned to  
13 lighting was spread equally across all luminaires. The O&M associated with post  
14 inspection and post painting was spread equally to all underground fed luminaires.

15

16 **Q51. How was depreciation expense allocated to the proposed E1 Option I Rate**  
17 **Schedule luminaire charges in the lighting model?**

18 A51. The total depreciation expense reflected in the E1 Option I Rate Schedule  
19 luminaire charges, as established in the Company's cost of service model  
20 supported by Witness Cejas Goyanes, is \$29.8 million. This reflects \$21.7 million  
21 depreciation for the directly assigned lighting asset accounts, and \$3.1 million for  
22 the distribution asset accounts allocated to lighting, and the balance associated  
23 with general and intangible plant accounts allocated to lighting.

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

9  
10 The depreciation expense for both the overhead and underground luminaire  
11 subaccounts (LED Overhead, LED Underground, and HID Overhead, HID  
12 Underground) was allocated to the respective overhead and underground  
13 luminaires based upon lighting technology, wattage and underlying original  
14 investment. For instance, all underground-fed mercury vapor luminaires received  
15 an allocation of depreciation expense from subaccount 373.05 (Street Lighting  
16 Luminaires – HID Underground) based upon the luminaire type's investment and  
17 underlying mercury vapor luminaire useful life.

18  
19 The depreciation expense that was allocated to lighting from distribution was  
20 allocated to all underground and overhead lighting based upon each luminaire  
21 type's system wattage -- the best representation of each lighting type's usage of the  
22 distribution system.

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1   **Q52. How was the revenue requirement for other taxes, return on investment and**  
2       **income tax allocated to the proposed E1 Option I Rate Schedule luminaire**  
3       **charges?**

4   A52. All other components were allocated to the various luminaire types in a manner  
5       similar to that employed for the related underlying depreciation expense. For the  
6       directly assigned street lighting asset subaccounts, other taxes, return on  
7       investment and income tax followed the allocation of net plant to each of the  
8       lighting types.

9  
10   **Q53. Do you believe the proposed allocation of costs reflected in the various E1**  
11       **Option I Rate Schedule luminaire charges is reasonable?**

12   A53. Yes. The methodology utilized in the lighting model to allocate each of the  
13       individual cost of service components discreetly, rather than in total, more  
14       accurately reflects the cost to provide lighting service to underground and  
15       overhead assets as well as the various lighting technologies. The use of the eight  
16       separate asset subaccounts for allocation of capital-related costs results in more  
17       accurate rate setting based upon both how the lights are fed as well as the lighting  
18       technology, wattage, and luminaire investment.

19

20   **Q54. How were the E1 Option II Rate Schedule charges developed?**

21   A54. The E1 Option II Rate Schedule charges were developed based upon a share of the  
22       production revenue requirement allocated by Witness Cejas Goyanes in the  
23       Company's cost of service model to the E1 Rate Schedule, a share of the  
24       distribution and customer service revenue requirements allocated by Witness  
25       Cejas Goyanes in the Company's cost of service model to the E1 Rate Schedule

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1 and a small allocation of the O&M expense directly assigned to the E1 Rate  
2 Schedule from Account 596. The allocations of revenue requirement from  
3 production, distribution and customer service to the E1 Option II Rate Schedule  
4 were accomplished on a per kWh basis across all E1 Option II rates. The proposed  
5 rates for the E1 Option II Rate Schedule are displayed in a luminaire charge,  
6 similar to that for Rate Schedule E1 Option I, and energy charges, both capacity  
7 and non-capacity, in a cent/kWh format.

8

9 **Q55. How were the E1 Option III Rate Schedule charges developed?**

10 A55. The E1 Option III Rate Schedule charges were developed based upon a share of  
11 the total production revenue requirement allocated by Witness Cejas Goyanes in  
12 the Company's cost of service model to the E1 Rate Schedule, a share of the total  
13 distribution revenue requirement allocated by Witness Cejas Goyanes in the  
14 Company's cost of service model to the E1 Rate Schedule, and a share of the  
15 customer service revenue requirement allocated by Witness Cejas Goyanes in the  
16 Company's cost of service model to the E1 Rate Schedule. The allocations of  
17 revenue requirement from production, distribution and customer service to the E1  
18 Option III Rate Schedule were performed on an equal energy basis across all E1  
19 Option III rates. The proposed E1 Option III Rate Schedule distribution and  
20 energy charges, both capacity and non-capacity, are displayed in a cent per kWh  
21 format, allowing for a transparent comparison of lighting costs for the various  
22 luminaire system wattages and the various lighting technologies.

23

24 **Q56. How does your proposed cost allocation methodology impact the present rates**  
25 **for the E1 Rate Schedule?**

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1 A56. The cost allocation methodology described above and employed in the lighting  
2 model reflects a collective revenue deficiency for the E1 Rate Schedule options.  
3

4 **Q57. What is your proposal regarding rate design in this proceeding for Rate**  
5 **Schedule E1 Option I rates?**

6 A57. A continuation of the gradual move towards rates which are entirely based upon  
7 cost of service for the lighting class is being proposed. Consensus on this  
8 methodology was reached in the lighting collaborative ordered in Case No. U-  
9 17767 and beginning with rate Case No. U-18014, the Rate Schedule E1 Option I  
10 lighting rates are being gradually moved to rates which are entirely based upon  
11 cost of service.  
12

13 **Q58. How were the Rate Schedule E1 Option I proposed rates developed in this**  
14 **proceeding?**

15 A58. The proposed Rate Schedule E1 Option I lighting rates were designed with two  
16 goals in mind; (1) continue the gradual move to rates which are entirely cost based  
17 and (2) minimize the impact of the proposed lighting rates on the monthly lighting  
18 bill for any municipality. Using the lighting rate model, the first step towards  
19 achievement of these goals was to limit the overall increase on any municipality  
20 and/or total lighting rate to 2.45 times the proposed average increase in revenue  
21 requirement. The second step of the process was to allocate the remaining revenue  
22 deficiency for the Rate Schedule E1 Option I class, on a percentage basis, to all  
23 the remaining lights.



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1     **Rate Schedule D9**

2     **Q59. How were the proposed rates for the D9 Rate Schedule determined?**

3     A59. The proposed luminaire rates for the D9 Rate Schedule for both commercial and  
4           residential OPL service were developed based upon the allocated and directly  
5           assigned distribution costs supported by Witness Cejas Goyanes in the Company's  
6           cost of service model. The luminaire rate design methodology employed in the  
7           lighting model for the D9 Rate Schedule mirrors the methodology employed for  
8           the E1 Rate Schedule with all allocated distribution costs assigned to luminaire  
9           charges based upon energy consumption and the directly assigned costs allocated  
10          based upon the underlying individual cost of service components.

11

12    **Q60. Are all of the proposed luminaire rates for the D9 Rate Schedule entirely cost-**  
13       **based?**

14    A60. No. The proposed rates for Rate Schedule D9 required the use of the same two-  
15       step methodology to gradually achieve cost-based intra-class rates that was  
16       employed for the E1 Option I Rate Schedule.

17

18    **Rate Schedule E2**

19    **Q61. How were the proposed Rate Schedule E2 charges determined?**

20    A61. The Rate Schedule E2 charges were developed based upon production, both  
21       capacity and non-capacity, and distribution revenue requirements allocated to Rate  
22       Schedule E2 customers by Witness Cejas Goyanes in the Company's cost of  
23       service model. Each of the revenue requirement amounts were divided by the total  
24       forecasted energy for the projected test period to arrive at a distribution rate, a non-  
25       capacity energy rate and a capacity energy rate in cents/kWh.

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1   **Q62. How has Witness Cejas Goyanes' presentation of the revenue deficiency for**  
2       **production in this case impacted your rate design?**

3   A62. To allocate the targets to the lighting tariff energy charges, both capacity and non-  
4       capacity, in the cost of service-based rate presentation, I have allocated the revenue  
5       deficiency for Rate Schedule E2 to the E2 rate directly and I have allocated the  
6       total D9 deficiency, and total E1 deficiency Rate Schedules to those energy rates  
7       in total.

8

9   **Q63. Will you please describe Exhibit A-16, Schedule F8?**

10   A63. This exhibit contains the proposed tariff sheet changes which result from the  
11       pricing changes described above.

12

13   **Q64. Does this complete your direct testimony?**

14   A64. 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-21860

QUALIFICATIONS  
  
AND  
  
DIRECT TESTIMONY  
  
OF  
  
MARGARET E. GUILLAUMIN

**DTE ELECTRIC COMPANY**  
**QUALIFICATIONS AND DIRECT TESTIMONY OF MARGARET E GUILLAUMIN**

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

2    A1.    My name is Margaret E. Guillaumin (she/her/hers). My business address is One  
3           Energy Plaza, Detroit MI, 48226. I am employed by DTE Electric Company (DTE  
4           Electric or Company) as Plant Director in the Energy Supply organization.

5

6    **Q2.    On whose behalf are you testifying?**

7    A2.    I am testifying on behalf of DTE Electric.

8

9    **Q3.    What is your educational background?**

10   A3.    My formal education consists of a Bachelor of Science degree in Chemical  
11           Engineering from Michigan Technological University. I have also completed  
12           several Company sponsored courses and have attended various seminars to further  
13           my professional development with DTE Electric.

14

15   **Q4.    What work experience do you have?**

16   A4.    I began my employment with DTE Electric in July 2003 in the engineering  
17           department at River Rouge Power Plant. Throughout my career with DTE Electric  
18           I have received various promotions with increasing levels of responsibility. These  
19           positions included several engineering roles at the St. Clair Power Plant beginning  
20           in November of 2003, Supervisor of Chemical Engineering for DTE Electric's  
21           fossil power plants in 2010, Manager of Laboratory and Field Support in 2012, Fuel  
22           Supply Manager at St. Clair Power Plant in 2014, and St. Clair Power Plant  
23           Maintenance Manager in 2016. In October of 2017, I was promoted to Plant  
24           Manager, Greenwood Energy Center, responsible for all day-to-day operation,  
25           maintenance, and engineering for the facility. In April 2019, I was given additional

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1 responsibilities that included Peakers and Ludington. In this expanded role I added  
2 to my responsibilities the operation, maintenance, and engineering of DTE  
3 Electric's natural gas and fuel oil Peakers as well as responsibilities for DTE  
4 Electric's interest in the Ludington Pumped Storage facility. In April of 2022, I  
5 was appointed Plant Manager, Blue Water Energy Center (BWEC), where I was  
6 responsible for transitioning the newly constructed facility through final  
7 commissioning activities to commercial operation. Following the commercial  
8 operation date, I was responsible for the day-to-day operation, maintenance, and  
9 engineering of the facility. In April 2023, I was promoted to Plant Director,  
10 Operations Performance. In this role my responsibilities included periodic outage  
11 planning and execution for DTE Electric's fossil power plants, strategic planning  
12 and long-term generation strategy, asset maintenance planning, and oversight of the  
13 St. Clair, Trenton Channel, and River Rouge Power Plants during  
14 decommissioning, as well as responsibilities for approving capital projects as a  
15 voting member of the Capital Governance Board.

16

17 **Q5. What are your current duties and responsibilities?**

18 A5. In March 2024 I was appointed to the role of Plant Director, Energy Supply. In  
19 addition to maintaining my responsibilities over the decommissioning sites, my role  
20 responsibilities transitioned to oversight of natural gas and peaker generating units  
21 in the DTE Electric fleet as well as DTE Electric's interest in the Ludington  
22 Pumped Storage facility.

23

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

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- |   |     |                                                                              |
|---|-----|------------------------------------------------------------------------------|
| 1 | A6. | Yes. I was the Company's Energy Supply witness in the 2024 DTE Electric Rate |
| 2 |     | Case, Case No. U-21534.                                                      |

Line  
No.

1 **Purpose of Testimony**

2 **Q7. What is the purpose of your testimony?**

3 A7. The overall purpose of my testimony is to support the reasonableness and prudence  
4 of the operations and maintenance (O&M) and capital investments for Energy  
5 Supply steam power generation, hydraulic power generation (Ludington), and other  
6 power generation (BWEC, peakers, and Battery Energy Storage Systems (BESS))  
7 for the historical test year ended December 31, 2023, the 24-month bridge period  
8 ending December 31, 2025, and the 12-month projected test period ending  
9 December 31, 2026. Although Energy Supply currently operates and maintains  
10 DTE Electric's fleet of wind and solar assets, the costs of these assets are supported  
11 in other regulatory proceedings. Therefore, throughout my testimony when I refer  
12 to Energy Supply assets, I am referring to only the fossil and energy storage assets,  
13 including hydraulic storage and BESSs. No part of my testimony includes Energy  
14 Supply renewable generation wind and solar assets as they are handled in other  
15 regulatory filings as noted above. I also address the following additional topics in  
16 my testimony:

17 1) I explain the forecasted changes affecting generation ratings on a yearly basis  
18 for 10 years looking forward (2023 through 2033). The changes are associated  
19 with projected retirements of current generating assets, the addition of new  
20 Energy Supply assets, as well as changes to existing units.

21 2) I provide a review of Energy Supply coal-fired and combined cycle unit  
22 availability for the most recent five years of actual performance and the next five  
23 years projected. In addition to discussing availability, I will also discuss the  
24 planned and unplanned outage performance for these same timeframes.

Line  
No.

- 1           3) I discuss Energy Supply’s capital Project Approval Team (PAT) process and its  
2           correlation to Association for the Advancement of Cost Engineering (AACE)  
3           cost estimating forecast accuracy classes.
- 4           4) For capital investments, I discuss how the Environmental Protection Agency’s  
5           (EPA) Steam Electric Effluent Limitation Guidelines (ELG) Rule affects  
6           required coal-fired generation investments.
- 7           5) I then provide details of the historical 2023 level of expenditures on a plant level  
8           basis and provide forecasts of expenditures to be incurred from January 1, 2024  
9           through December 31, 2026. This data shows the levels of expenditures related  
10          to routine maintenance, environmental compliance requirements, as well as  
11          expenditures related to safety and general reliability that have been and will be  
12          made over the timeframes of this case. These discussions on capital investments  
13          cover the Energy Supply generation and hydraulic plants including the coal-fired  
14          and gas-fired steam units, the Ludington pumped storage units, the Blue Water  
15          Energy Center (BWEC) combined cycle unit, the peaking units, and new energy  
16          storage.
- 17          6) I also support the multiple known and measurable changes in Energy Supply’s  
18          O&M expenses that will span the timeframe from the 2023 historic test year in  
19          this case to the projected test year, ending December 31, 2026.

20

21   **Q8.    Are you sponsoring any exhibits in this proceeding?**

22   A8.    Yes. I am sponsoring the following exhibits:

| <u>Exhibit</u> | <u>Schedule</u> | <u>Description</u>                                                  |
|----------------|-----------------|---------------------------------------------------------------------|
| A-6            | F1              | Planned Long Range Generation Changes (Steam,<br>Hydraulic & Other) |



Line  
No.

|    |      |      |                                                    |
|----|------|------|----------------------------------------------------|
| 1  | A-6  | F2   | Energy Supply Coal and Combined Cycle Unit         |
| 2  |      |      | Performance                                        |
| 3  | A-12 | B5.1 | Projected Capital Expenditures – Steam, Hydraulic, |
| 4  |      |      | and Other Power Generation                         |
| 5  | A-13 | C5.1 | Projected Operation and Maintenance Expenses –     |
| 6  |      |      | Steam Power Generation                             |
| 7  | A-13 | C5.4 | Projected Operation and Maintenance Expenses –     |
| 8  |      |      | Hydraulic Power Generation                         |
| 9  | A-13 | C5.5 | Projected Operation and Maintenance Expenses –     |
| 10 |      |      | Other Power Generation                             |

11

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

13 A9. Yes, they were.

14

15 **Q10. How is your testimony organized?**

16 A10. My testimony consists of the following three (3) parts:

17 Part I Energy Supply Plant Capacity and Availability

18 Part II Energy Supply Capital Investments

19 Part III Energy Supply Operation and Maintenance Expenses

20

21 **Part I – Energy Supply Plant Capacity and Availability**

22 **Energy Supply Net Summer Installed Capacity**

23 **Q11. Can you provide an overview of DTE Electric's fossil and hydraulic assets?**

24 A11. As of January 1, 2023, the Company's owned fossil and hydraulic generation based  
25 on installed summer capacity ratings totaled 9,166 MW and was comprised of:

Line  
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|   |                                               |                 |
|---|-----------------------------------------------|-----------------|
| 1 | <u>Rated Capacity (Summer) as of 1/1/2023</u> |                 |
| 2 | Fossil Steam                                  | 6,012 MW        |
| 3 | Peaking Plant                                 | 2,032 MW        |
| 4 | Pumped Storage                                | <u>1,122 MW</u> |
| 5 | Total Fossil/Hydraulic System                 | <u>9,166 MW</u> |

6

7 The Company's 6,012 MWs of fossil steam plant include coal-fired units that  
8 provided 4,100 MW of capacity and gas-fired units that provide an additional 1,912  
9 MW of capacity as shown below:

10

11 Rated Capacity as of 1/1/2023

|    |                                   |                              |                  |
|----|-----------------------------------|------------------------------|------------------|
| 12 | <u>Coal-fired Steam Plants</u>    | <u>Net Summer Capability</u> | <u>No. Units</u> |
| 13 | Belle River (DTE ownership)       | 1,034 MW                     | 2                |
| 14 | Monroe                            | <u>3,066 MW</u>              | <u>4</u>         |
| 15 | Total Coal-fired Capacity (Steam) | <u>4,100 MW</u>              | <u>6</u>         |

16

|    |                                  |                              |                  |
|----|----------------------------------|------------------------------|------------------|
| 17 | <u>Gas-fired Steam Plants</u>    | <u>Net Summer Capability</u> | <u>No. Units</u> |
| 18 | Greenwood                        | <u>785 MW</u>                | <u>1</u>         |
| 19 | Total Gas-fired Capacity (Steam) | <u>785 MW</u>                | <u>1</u>         |

20

|    |                                        |                              |                  |
|----|----------------------------------------|------------------------------|------------------|
| 21 | <u>Gas-fired Combined Cycle Plants</u> | <u>Net Summer Capability</u> | <u>No. Units</u> |
| 22 | Blue Water Energy Center               | <u>1,127 MW</u>              | <u>1</u>         |
| 23 | Total Gas-fired CCGT Capacity          | <u>1,127 MW</u>              | <u>1</u>         |

Line  
No.

1 The Michigan Public Power Agency (MPPA) is joint owner of Belle River Power  
2 Plant and its ownership entitlement is 18.61% (236 MW) of the plant. The MPPA  
3 ownership of Belle River Power Plant is not included in the 1,034 MW shown  
4 above.

5  
6 DTE Electric's peaking plants, along with DTE Electric's ownership share of the  
7 Ludington Pumped Storage facility, jointly owned with Consumers Energy, are  
8 shown below:

9  
10 Rated Capacity as of 1/1/2023

| 11 | <u>Peaking and Pumped Storage</u>     | <u>Net Summer Capability</u> | <u>No. Units</u> |
|----|---------------------------------------|------------------------------|------------------|
| 12 | Gas/Oil Combustion Turbines           | 1,904 MW                     | 37               |
| 13 | (11 locations)                        |                              |                  |
| 14 | Diesel Generators (10 locations)      | <u>128 MW</u>                | <u>46</u>        |
| 15 | Total Peaking Capacity                | 2,032 MW                     | 83               |
| 16 |                                       |                              |                  |
| 17 | Ludington Pumped Storage              | <u>1,122 MW</u>              | <u>6</u>         |
| 18 | Total Pumped Storage/Peaking Capacity | <u>3,154 MW</u>              | <u>89</u>        |

19  
20 **Q12. Can you provide a summary of Exhibit A-6, Schedule F1 titled "Planned Long**  
21 **Range Generation Changes (Steam, Hydraulic, & Other) Years 2023 through**  
22 **2033"?**

23 A12. Exhibit A-6, Schedule F1 provides the 2023 actual generation rating changes and a  
24 10-year projection of the forecasted changes at Energy Supply units through 2033.  
25 Changes are based on the forecasted timing of upcoming unit retirements,

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1 development of new Energy Supply assets, and modifications to existing assets.  
2 Generation changes for the future are included in the Company's filed Integrated  
3 Resource Plan (IRP) cases. Following the scope of the purpose of my testimony as  
4 described above, this exhibit does not include new or existing renewable resources.

5

6 **Q13. Can you explain the yearly generation facility changes shown on Exhibit A-6,**  
7 **Schedule F1 for 2023-2033?**

8 A13. The changes for 2023 are shown on lines 1 and 2 of Exhibit A-6, Schedule F1. In  
9 2023, Northeast 11-1 peaker (15 MW) was formally retired because significant in-  
10 service damage experienced in 2019 was determined to be uneconomical to repair.  
11 Additionally, the five Slocum peakers (14 MW in total) were retired in 2023 to  
12 facilitate the construction of the new Slocum Battery Energy Storage System  
13 (BESS).

14

15 The changes for 2024 are shown on lines 4 and 5 of Exhibit A-6, Schedule F1.  
16 During 2024, the Company retired the four River Rouge 11 peakers and the two St.  
17 Clair 12 peakers, representing a combined 16 MW of summer peaking capacity.

18

19 The forecasted changes for 2025 are shown on lines 7-9 of Exhibit A-6 Schedule  
20 F1. During 2025, the Company plans to suspend the operations of the Fermi 11-3  
21 and 11-4 peakers, representing a combined 25 MW of summer peaking capacity,  
22 and Belle River Unit 1 is projected to convert from coal-fired to natural gas-fired  
23 operations without a change in unit rating. Additionally, the Slocum Battery  
24 Energy Storage System (BESS), with a rating of 14 MW, is projected to be

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1 completed in 2025 replacing the peakers previously located at the site that were  
2 retired in 2023.

3 The forecasted changes for 2026 are shown on lines 11-12 of Exhibit A-6, Schedule  
4 F1. In 2026, the Trenton Channel 220 MW BESS is projected to commence  
5 operation, and Belle River Unit 2 is projected to convert from coal-fired to natural  
6 gas-fired operations without a change in unit rating.

7  
8 No changes are forecasted for 2027 in Exhibit A-6, Schedule F1.

9  
10 The forecasted changes for 2028 are shown on lines 16-17 of Exhibit A-6 Schedule  
11 F1. In 2028, consistent with the Order dated July 26, 2023, in the Company's 2022  
12 IRP Settlement Agreement in Case No. U-21193, the Company projects retiring  
13 Monroe Units 3 and 4, representing a combined 1,535 MW of coal-fired summer-  
14 rated capacity, and commencing operation of a 275 MW BESS.

15  
16 No changes are forecasted in Exhibit A-6, Schedule F1 from 2029 through 2031.

17  
18 The forecasted change for 2032 is shown on line 25 of Exhibit A-6, Schedule F1.  
19 In 2032, consistent with the Order dated July 26, 2023 in the Company's 2022 IRP,  
20 the Company projects retiring Monroe Units 1 and 2, representing a combined  
21 1,531 MW of coal-fired summer-rated capacity.

22  
23 No changes are forecasted for 2033 in Exhibit A-6, Schedule F1.

Line  
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1 **Energy Supply Plant Performance**

2 **Q14. How is the Company's Energy Supply plant performance monitored and**  
3 **calculated?**

4 A14. Energy Supply utilizes Equivalent Availability Factor (EAF), Planned Outage  
5 Factor (POF), and Random Outage Factor (ROF) to monitor overall unit  
6 performance. EAF is equal to 100 minus the POF minus ROF. Equivalent  
7 availability is equal to total possible megawatt-weeks minus planned outage  
8 megawatt-weeks minus random outage megawatt-weeks (including full and partial  
9 derates) divided by total possible megawatt-weeks. Total possible megawatt-weeks  
10 are calculated by multiplying the net demonstrated capacity of the unit by the weeks  
11 in the time-period (52 weeks per year). Planned outage megawatt-weeks refers to  
12 the equivalent number of weeks in the time-period that the unit is not available due  
13 to scheduled maintenance multiplied by the capacity that is out of service. Random  
14 outage megawatt-weeks is the number of weeks of unit unavailability caused by an  
15 outage or derate that is not planned or scheduled, multiplied by the capacity that is  
16 out of service.

17

18 **Q15. What are the major drivers of unit unavailability?**

19 A15. There are three major drivers of unit unavailability impacting plant performance:  
20 (1) planned full unit maintenance outages, (2) unplanned random unit outages, and  
21 (3) derates, which are partial unit outages, which can be planned or unplanned.

22

23 Planned full unit outages and planned derates are those outages for which the  
24 Company has developed long range maintenance plans designed to sustain unit  
25 performance, install required environmental systems, and proactively address

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1 emerging reliability issues. Unplanned unit outages and unplanned derates are  
2 those that occur due to either reliability issues common across the industry or  
3 unusual events which are unique to a specific DTE Electric plant or unit.

4

5 **Q16. Can you explain the Company's 2023 total Energy Supply plant availability**  
6 **performance?**

7 A16. The EAF for Energy Supply steam, hydraulic, and other power generation assets  
8 was 78.7% for the 2023 historic period. This 78.7% equivalent availability was the  
9 result of an 8.7% ROF and a 12.6% POF. In 2023, Energy Supply assets included  
10 Belle River, Blue Water Energy Center, Greenwood, Monroe, Ludington, and  
11 peaker power plants. Energy Supply availability for 2023 was reduced by planned  
12 major overhaul maintenance outages completed on Monroe Unit 1 and multiple  
13 peaker units. Less comprehensive planned outages were completed on many units  
14 to prepare units for or recover from high peak load summer operations.

15

16 **Q17. What was the equivalent availability specific to the coal-fired and combined**  
17 **cycle units within Energy Supply in 2023?**

18 A17. As shown on line 4 of Exhibit A-6, Schedule F2, coal-fired and combined cycle  
19 plants had an equivalent availability of 80.1% in 2023 as a result of an 8.1% ROF  
20 and a 11.8% POF for those units. Coal-fired plants included the Belle River and  
21 Monroe Power Plants. The Blue Water Energy Center combined cycle plant is also  
22 included in the availability metrics.

23

24 **Q18. How does the forecasted future coal-fired and combined cycle unit availability**  
25 **compare to the actual historical availability?**

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1 A18. As shown in Exhibit A-6, Schedule F2, the average coal-fired and combined cycle  
2 unit availability for 2020-2024 was 74.6% while the forecast of average coal-fired  
3 and combined cycle unit availability for 2025-2029 is 80.1%. The older and less  
4 reliable coal-fired power plants were retired by 2022, resulting in an increase in  
5 availability for 2023 and beyond.

6

7 **Part II – Energy Supply Capital Investments**

8 **Q19. Can you please provide an overview of your Part II discussion?**

9 A19. Yes. In this section of my testimony, I will discuss the following:

- 10 • Energy Supply's Capital Planning Process
- 11 • Energy Supply's Project Approval Team (PAT) Process and Correlation to
- 12 Association for the Advancement of Cost Engineering (AACE) Class Cost
- 13 Levels
- 14 • ELG Rule Compliance
- 15 • Energy Supply's 2023-2026 Capital Projects Summary
- 16 • Energy Supply's Non-Routine Capital Investments
- 17 • Energy Supply's Routine Capital Investments
- 18 • Energy Supply's Allowance for Funds Used During Construction (AFUDC)
- 19 Estimate
- 20 • Energy Supply's Removal Costs, Plant in Service and CWIP schedule

21

22 **Energy Supply's Capital Planning Process**

23 **Q20. Can you explain Energy Supply's capital planning process?**

24 A20. Yes. Capital projects are initiated to support safety, regulatory requirements,  
25 environmental compliance, plant-level reliability plans, Original Equipment



Line  
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1 Manufacturer (OEM) recommendations, or the engineering recommendations of  
2 Energy Supply's equipment and system experts. Capital expenditure requests  
3 require the development of a plant management approved project request that  
4 includes a detailed explanation of the project and an initial estimate of the costs and  
5 customer benefits associated with the project. Projects are then further developed  
6 including work scope identification and ranking based on customer-centric  
7 economic considerations and other important drivers such as safety requirements,  
8 environmental regulations, and outage timing opportunities. The planned outage  
9 schedule heavily influences capital project timing since many capital projects are  
10 implemented during longer duration planned outages to minimize implementation  
11 impact on plant availability. During these planned outages, inspections are  
12 completed on critical systems to ensure that the outage being executed addresses  
13 the work needed to sustain future unit reliability. These inspections can reveal  
14 unanticipated damage because many systems cannot be thoroughly inspected or  
15 evaluated until they are disassembled during an outage.

16

17 Once capital project requests are fully developed, they are prioritized and presented  
18 for management review and approval. The review process focuses on ensuring that  
19 the projects utilize the best solution to address the issue at hand and represent the  
20 most cost-effective method for accomplishing the proposed work. Projects are  
21 approved if they are required to meet safety requirements and/or environmental  
22 compliance, are justified by an economic evaluation or represent normal/routine  
23 plant component replacements required for continued plant operations that are  
24 capitalized per authorized accounting policy.

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1 In summary, the capital spending and approval process is designed to identify the  
2 optimal allocation of capital resources to meet safety requirements and  
3 environmental compliance while maintaining overall reliability performance and  
4 minimizing costs.

5

6 **Q21. What do you mean by projects being justified by economic evaluation?**

7 A21. The prioritization of economic projects is based on a cost benefit analysis using a  
8 calculated internal rate of return (IRR) analysis, performed by comparing the costs  
9 of implementing the new project to its customer benefits over a specified period of  
10 time. Included in the analysis are projected capital expenditures, future avoided  
11 outages, heat rate (efficiency), and fuel blending capabilities. Future avoided plant  
12 outage impacts include the value of avoiding unplanned events such as boiler tube  
13 failures, condenser or feedwater heater leaks, and turbine blade failures. The IRR  
14 of a project is based on the anticipated O&M, capital investment, and energy and  
15 capacity market value of the unit's operations with and without the project being  
16 implemented over its useful life.

17

18 **Q22. What would be the consequences of not completing the capital projects**  
19 **requested in the instant case?**

20 A22. Failure to complete the approved capital projects described in this case could  
21 negatively affect plant reliability, environmental compliance, power supply and  
22 generation plant costs, and/or safety.

23

24 **Q23. Can you explain the governance process for approval of Energy Supply's**  
25 **capital projects?**

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1 A23. The capital governance process includes the documentation of project assumptions,  
2 calculation of costs and customer benefits, and a rigorous internal review. Projects  
3 costing less than \$250,000 are approved by plant management, utilizing a project  
4 appropriation form, within a budget established based on historic plant  
5 expenditures. These projects generally do not require engineering and often reflect  
6 replacement-in-kind.

7  
8 Projects that cost greater than \$250,000 but less than \$10 million and/or projects  
9 that require engineering are approved by the Energy Supply Capital Governance  
10 Board (CGB) which consists of plant directors, the Director of Engineering, and  
11 the Vice President of Energy Supply. A PAT form is utilized to record CGB  
12 approvals.

13  
14 Projects greater than \$10 million require senior corporate executive approval, while  
15 projects greater than \$50 million require approval by the Finance Committee of  
16 DTE Energy's Board of Directors. All projects greater than \$10 million must be  
17 authorized by a Capital Appropriations Request Form (CARF) approved by the  
18 appropriate Company representatives.

19

20 **Energy Supply's PAT Process and Correlation to AACE Cost Estimating Forecast**

21 **Accuracy Classes**

22 **Q24. Is the Company including new detail related to Energy Supply's Project**  
23 **Approval Team (PAT) stage gate approval process in the instant rate case that**  
24 **has historically not been provided?**

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1 A24. Yes. The Commission encouraged DTE Electric to add additional detail on the  
2 Project Approval Team (PAT) stage gate approval process or use AACE cost  
3 estimate classifications, or something similar. (MPSC Case No. U-21534 Order  
4 dated January 23, 2025, page 44).

5  
6 **Q25. What information is the Company providing in response to the MPSC's**  
7 **request for additional information regarding the PAT process?**

8 A25. In response to the Order in Case No. U-21534, I provide detail below that shows  
9 the correlations between Energy Supply's PAT approval process and AACE cost  
10 estimate classifications.

11  
12 **Q26. Can you describe the Energy Supply PAT levels as they relate to the respective**  
13 **phases of capital projects?**

14 A26. Pre-PAT-0 projects are considered to be in the conceptual design phase. At this  
15 stage, alternative solutions are being considered and explored. Cost estimates are  
16 based on rough order of magnitude and rules of thumb, and project scopes are not  
17 well-defined. Projects in the pre-PAT-0 stage are not presented in the rate case.

18  
19 PAT-0 approval indicates a project has been vetted and authorized by Company  
20 management to start accumulating charges against capital work orders. It also  
21 represents the best solution to address the problem being worked. PAT-0 approval  
22 indicates that the project scope is known and that the limits of that scope are known,  
23 meaning that items in scope and not included in scope have been defined. At the  
24 time of PAT-0 approval, a cost estimate has been approved which is based on the

Line  
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1 cost of similar work, vendor indicative cost estimates, and/or project manager  
2 inputs.

3  
4 PAT-1 work level approval authorizes bidding of long-lead materials, contracts for  
5 construction management, and Engineering-Procurement-Construction (EPC)  
6 contracts. It also authorizes placement of orders for long-lead material and  
7 completion of detailed engineering. Cost estimates developed for PAT-0 approval  
8 are refined using material proposals and detailed design to generate PAT-1 cost  
9 estimates.

10

11 PAT-2 work level approval authorizes construction of the project. Drawing  
12 updates, administrative closure, and post-project review of the total work effort are  
13 also completed within the PAT-2 project approval envelope. The PAT-1 cost  
14 estimates are further refined using labor and material proposals and complete  
15 design to develop PAT-2 cost estimates for approval.

16

17 **Q27. What is AACE and how is it relevant to capital project cost estimating as**  
18 **recommended by the MPSC Staff?**

19 A27. AACE International is the Association for the Advancement of Cost Engineering.  
20 The association is a collection of professional cost engineers that work to advance  
21 consistency in major project cost estimating. To this end, they support use of a  
22 five-stage cost estimating classification system for project cost estimating accuracy  
23 based on the quality and completeness of the data available to cost estimators of  
24 major construction projects. The AACE five stages of cost estimating can be  
25 generally described as follows: Class 5 (Rough order of Magnitude), Class 4

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1 (Feasibility Study Estimate), Class 3 (Budget Estimate), Class 2 (Bid Estimate),  
2 and Class 1 (Full Detail, Firm Price Estimate).

3 **Q28. How do the PAT approval stages correlate to AACE cost estimate**  
4 **classifications?**

5 A28. The table below shows the general relationship between PAT approval stages,  
6 AACE cost estimate classifications, and the type of information found in each.  
7 Some projects are exceptions to the relationship between PAT approval stages and  
8 AACE cost estimates shown in Table 1; for example, a routine project in PAT-0  
9 performed frequently and recently may qualify as an AACE Class 1 or 2 project  
10 estimate.

11

12 *Table 1* General relationship between PAT Project Levels and AACE Cost

13 Estimate Classifications

| AACE Estimate Classification | AACE Cost Estimate Stage         | PAT Project Level | PAT Level of Project Definition                                                                                                                                                                                                                        |
|------------------------------|----------------------------------|-------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <b>Class 5</b>               | Rough order of magnitude         | <b>Pre-PAT 0</b>  | Conceptual design phase; alternative solutions are being considered and explored. Cost estimate based on rough order of magnitude.                                                                                                                     |
| <b>Class 4</b>               | Feasibility study estimate       |                   |                                                                                                                                                                                                                                                        |
| <b>Class 3</b>               | Budget estimate                  | <b>PAT 0</b>      | Project reviewed and authorized by Company management and project scope defined. Cost estimate built using budgetary proposals and/or previous similar project proposals.                                                                              |
| <b>Class 2</b>               | Bid estimate                     | <b>PAT 1</b>      | Authorized for bidding of long-lead materials, construction management contracts, and EPC contracts. High-level schedule is developed. Cost estimate refined using material proposals and detailed design.                                             |
| <b>Class 1</b>               | Full detail, firm price estimate | <b>PAT 2</b>      | Labor and material proposals received and detailed schedule developed. Authorized for project construction. Includes drawing updates and administrative closure. Cost estimate further refined using labor and material proposals and complete design. |

Line  
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1 **Q29. What was the Commission's treatment of Energy Supply capital projects**  
2 **based on MPSC Staff's application of AACE in the Company's 2024 Rate**  
3 **Case, Case No. U-21534?**

4 A29. The Commission did not approve recovery of 15-20% of projected 2024 and 2025  
5 Energy Supply routine capital expenditures for certain projects based on MPSC  
6 Staff's application of AACE<sup>1</sup>. Witness Ludlow of West Monroe (on behalf of the  
7 Company) discusses the implications of using AACE to justify disallowances and  
8 the risk associated with that approach.

9

10 **ELG Rule Compliance**

11 **Q30. How does the EPA's Steam Electric ELG Rule affect the Company?**

12 A30. As discussed in more detail by Company Witness Lee, the EPA's ELG Rule  
13 regulates how electric utilities must manage certain wastewaters from coal-fired  
14 power plants. On October 13, 2020, the EPA finalized the ELG Reconsideration  
15 Rule, which revised some requirements from the 2015 ELG Rule and added time-  
16 based options for complying with the updated requirements for Bottom Ash  
17 Transport Water (BATW) and Flue Gas Desulfurization (FGD) wastewater.  
18 Subsequently, on March 29, 2023, the EPA published a Direct Final Rule which  
19 extended the deadline for power generating units to opt-in to the cessation of coal  
20 compliance subcategory from the 2020 ELG Rule, which allows for operation of a  
21 unit until end of 2028 in lieu of installing a technology-based compliance option.  
22 Bottom ash transport water cannot be discharged to the environment after  
23 December 31, 2025, from a coal-fired power plant unless the plant has committed  
24 to ceasing coal-fired operations by the end of 2028, by opting into the cessation of

---

<sup>1</sup> Case No. U-21534 Order dated January 23, 2025, pages 42-45.

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1 coal compliance subcategory. Regarding FGD wastewater streams, plants with  
2 FGD systems can comply with one set of limits by December 31, 2025 or comply  
3 with a set of more stringent limits by December 31, 2028 if the plant plans to  
4 continue coal-fired operations past 2028. Fly ash transport water (FATW)  
5 discharge limitations were not altered in the Reconsideration Rule and Direct Final  
6 Rule and continued to have a December 31, 2023 compliance date.

7

8 **Q31. Did the Company submit any filings under the ELG Reconsideration Rule?**

9 A31. Yes. To utilize the ELG Reconsideration Rule's time-based options, companies  
10 were required to submit a Notice of Planned Participation (NOPP) to their state  
11 permitting agency. The Company filed NOPPs for Monroe and Belle River Power  
12 Plants. Please refer to my more specific testimony for the Monroe and Belle River  
13 Power Plants below, as well as to Company Witness Lee's testimony, for more  
14 information.

15

16 **Q32. Has the Company made a formal commitment regarding how Belle River**  
17 **Power Plant will comply with ELG Rules?**

18 A32. Yes. The NOPP that DTE Electric filed with the Michigan Department of  
19 Environment, Great Lakes, and Energy (EGLE) on October 13, 2021 indicated a  
20 commitment to cease coal-fired operations at Belle River Power Plant. The fuel  
21 conversion at Belle River qualifies for ELG compliance as it results in ceasing coal-  
22 fired operations. This decision allows the Company to avoid installing new ELG-  
23 compliant bottom ash transport technology by the end of 2025.



Line  
No.

1   **Q33. How did the Company comply with the FATW-portion of the ELG Rule at**  
2       **Monroe Power Plant?**

3   A33. The FATW-portion of the ELG Rule required companies to cease water discharges  
4       related to the transport of fly ash by the end of 2023. A project to install piping and  
5       silos and other infrastructure for the dry transport of fly ash from Monroe Power  
6       Plant boilers to a permitted storage area was completed in 2023, meeting the  
7       required compliance date.

8  
9   **Q34. How will the Company comply with the BATW-portion of the ELG Rule at**  
10       **Monroe Power Plant?**

11   A34. Monroe Units 1 and 2 are required to comply with the BATW-portion of the ELG  
12       Rule by the end of 2025. The Company plans to terminate the use of water for  
13       bottom ash transport on Monroe Units 1 and 2. In place of water conveyance, a dry  
14       drag chain conveyor system will be installed. This project was approved by the  
15       Company in 2022, is fully underway and will meet the required compliance date.

16  
17       Monroe Units 3 and 4 will not be required to terminate the use of water for bottom  
18       ash transport by the end of 2025. The Company submitted a NOPP for BATW on  
19       Monroe Units 3 and 4 and will comply with the BATW-portion of the ELG Rule  
20       by retiring Monroe Units 3 and 4 by the end of 2028, thereby eliminating their  
21       production of BATW and the need and expense to install a new ash transport  
22       system.

23  
24   **Q35. How does the Company plan to comply with the FGD wastewater-portion of**  
25       **the ELG Rule at Monroe Power Plant?**

Line  
No.

1 A35. Monroe Power Plant is required to comply with the FGD wastewater-portion of the  
2 ELG Rule by the end of 2025, unless the Company participates in the Voluntary  
3 Incentives Program (VIP) contained in the 2020 ELG Rule. The VIP allows  
4 compliance to be achieved by the end of 2028 if the Company agrees to meet more  
5 stringent FGD wastewater effluent limitations. The Company filed a VIP NOPP in  
6 October 2021, allowing it to evaluate alternative compliance technologies for  
7 Monroe Units 1 and 2, which it is currently doing.

8  
9 The retirements of Monroe Units 3 and 4 in 2028 will eliminate the production of  
10 FGD wastewater on those units, thereby eliminating the need and expense to install  
11 FGD wastewater treatment systems on those units. Consequently, the Company  
12 filed a cessation of coal compliance subcategory NOPP in April 2023.

13

14 **Energy Supply's 2023-2026 Capital Projects Summary**

15 **Q36. Can you provide a high-level discussion of the routine and non-routine capital**  
16 **expenditures being made by the Company for steam, hydraulic, and other**  
17 **power generation during the historical year 2023, the bridge period and the**  
18 **projected test period ending December 31, 2026?**

19 A36. The Company's Energy Supply group makes routine ongoing expenditures across  
20 its existing generation fleet (steam, hydraulic, and other power generation) to  
21 maintain safe, environmentally compliant, reliable, and efficient operations. Most  
22 of these routine expenditures are primarily for Monroe and Belle River Power Plant  
23 projects. To a lesser degree, there are routine capital expenditures for the remaining  
24 generation assets including Blue Water Energy Center, Greenwood Energy Center,  
25 Ludington, and peakers.

Line  
No.

1 Non-routine capital project expenditures are driven by steam power generation unit  
2 upgrades with a heavy focus on environmentally mandated work at Monroe Power  
3 Plant. Other major non-routine capital projects included in the instant case are  
4 related to decommissioning and environmental remediation projects at retired coal  
5 plants and construction of new BESSs.

6

7 **Q37. Can you explain Exhibit A-12, Schedule B5.1 entitled, “Projected Capital**  
8 **Expenditures Steam, Hydraulic and Other Power Generation” in more detail?**

9 A37. Exhibit A-12, Schedule B5.1 is a 9-page exhibit. Page 1 summarizes both “routine”  
10 and “non-routine” capital expenditures for 2023 (the historical actual test period)  
11 through the bridge period and the 12 months ending December 31, 2026 (the  
12 projected test period) for Steam Power Generation, Hydraulic Power Generation  
13 (Ludington Pumped Storage), and Other Power Generation. Page 2 provides  
14 additional detail for major non-routine capital expenditures for Steam, Hydraulic,  
15 and Other Power Generation. Page 3 summarizes routine Steam, Hydraulic, and  
16 Other Power Generation capital expenditures by plant site and major category.  
17 Pages 4 through 7 provide additional detail for the routine maintenance projects  
18 with expenditures of greater than \$1 million for 2023 through December 31, 2026.  
19 Page 8 summarizes AFUDC included in the routine and non-routine capital  
20 expenditures. Finally, page 9 summarizes the removal cost, plant in service, and  
21 CWIP assumptions included in the capital forecast.

22

23 **Q38. Can you provide additional details concerning Exhibit A-12, Schedule B5.1,**  
24 **page 1 of 9 entitled, “Projected Capital Expenditures Steam, Hydraulic, and**  
25 **Other Power Generation”?**

Line  
No.

1 A38. Yes. Line 2, Routine Steam Power Generation, includes capital expenditures  
2 necessary to operate and maintain Energy Supply's fossil steam power plant sites.  
3 Included are projects related to safety, boiler and turbine work, cables and controls,  
4 balance of plant projects and maintenance of environmental control systems.  
5 Safety expenditures include the capital projects necessary to maintain a safe work  
6 environment and meet applicable safety regulations and standards. Boiler and  
7 turbine work include the capital expenditures intended to maintain boiler or turbine  
8 operations, replace unreliable systems or equipment, support heat rate (efficiency),  
9 and/or address operating and maintenance problems related to the boiler and turbine  
10 systems. Examples of these projects include replacement of worn or damaged  
11 turbine blades, air heater baskets, and boiler tube sections such as waterwalls,  
12 reheaters, superheaters, and economizers. Cables and controls expenditures include  
13 the capital expenditures to replace or improve distributed control systems, large  
14 power cables, main unit transformers, and electrical switchgear. The balance of  
15 plant area expenditures includes the capital associated with mobile equipment,  
16 station air compressors, general service water systems, fuel handling equipment and  
17 systems, and plant vehicles and computers. Routine environmental expenditures  
18 include the capital necessary to maintain operations of existing environmental  
19 control and monitoring equipment. An example of routine environmental  
20 expenditures is the ongoing replacement of the Selective Catalytic Reduction  
21 (SCR) catalyst beds installed at Monroe Power Plant that are needed to comply with  
22 nitrogen oxides (NOx) emissions limits. These routine environmental capital  
23 expenditures associated with existing environmental systems differ from the non-  
24 routine environmental capital expenditures required to install any future new  
25 environmental systems.

Line  
No.

1 Line 3, Non-Routine Steam Power, includes capital expenditures related to  
2 environmental compliance projects, site decommissioning, environmental  
3 remediation, and required equipment modifications related to retired power  
4 generation assets, as well as other plant level projects such as physical and cyber  
5 security at generation sites.

6

7 Line 6, Routine Hydraulic Power Generation, includes the Company's share of the  
8 routine capital expenditures necessary to operate and maintain the Ludington  
9 Pumped Storage facility.

10

11 Line 7, Non-Routine Hydraulic Production Plant, includes the Company's share of  
12 the capital expenditures related to the efficiency upgrade project at the Ludington  
13 Pumped Storage facility. This multi-year project included installation of new  
14 higher efficiency hydraulic turbines, main unit transformers, and upgraded  
15 generators on all six units.

16

17 Line 10, Routine Other Power Generation, includes capital expenditures related to  
18 maintaining peaker and combined cycle operations, including routine overhauls.

19

20 Line 11, Non-Routine Other Power Generation, primarily includes capital  
21 expenditures related to the development and construction of new BESSs.

22

23 Lines 15 and 16 include Monroe regulatory asset routine and non-routine capital  
24 expenditures. Consistent with the MPSC's Order in the Company's 2022 IRP

Line  
No.

1 filing, Case No. U-21193, the Company is including 2025 and all future Monroe  
2 capital expenditures in the regulatory asset category.

3 **Energy Supply's Non-Routine Capital Investments**

4 **Q39. Can you summarize Exhibit A-12, Schedule B5.1, page 2 of 9 entitled,**  
5 **"Projected Capital Expenditures Steam, Hydraulic, and Other Power**  
6 **Generation – Non-Routine"?**

7 A39. Page 2 of Exhibit A-12, Schedule B5.1 provides project level detail for non-routine  
8 capital expenditures completed and planned for Steam Production, Hydraulic, and  
9 Other Power Generation from the start of 2023 through December 31, 2026.

10

11 **Q40. Can you explain line 2 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

12 A40. Line 2 (Belle River Fuel Conversion) represents a project to convert the Belle River  
13 Power Plant's fuel source from coal to natural gas, consistent with the Company's  
14 approved 2022 IRP Settlement Agreement and the Company's clean energy goals.  
15 The Order in Case No. U-21193 also included preapproval of the Belle River Fuel  
16 Conversion project. The total projected expenditures for this project, spanning 2022  
17 through 2027, are consistent with the \$125 million cost approved in Case No. U-  
18 21193.

19

20 In 2023, \$1.9 million was spent on this project. An engineering, procurement, and  
21 construction (EPC) contractor was selected for the conversion of Belle River Units  
22 1 and 2. Material was procured including components for burner and ignitor  
23 modifications, ductwork modifications, air heater modifications, low and high-  
24 pressure gas reducing skids, a gas detection monitoring system, gas yard

Line  
No.

1 equipment, and components for associated electrical and controls upgrades.  
2 Additionally, a limited notice to proceed was issued in December 2023 to the  
3 selected EPC contractor.

4 In 2024, \$43.2 million was spent to continue material procurement and complete  
5 detailed design, including erection arrangements and the controls upgrade  
6 requirements.

7  
8 In 2025, \$36.7 million is projected to be spent on this project. 2025 work scope  
9 includes installation of a natural gas pipeline from a nearby high-pressure interstate  
10 pipeline to the power plant, constructing the in-plant gas piping system, and  
11 controls systems for Belle River Unit 1, and retrofitting the Belle River Unit 1 boiler  
12 with natural gas burners in its fall periodic outage.

13  
14 In 2026, \$32.3 million is projected to be spent for construction of the in-plant gas  
15 piping system and controls systems for Belle River Unit 2 and retrofitting the unit  
16 with natural gas burners in its fall periodic outage.

17

18 **Q41. Can you explain line 3 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

19 A41. Line 3 (Belle River Bottom Ash Basin Modification (CCR)) represents a project  
20 that retrofitted the north and south bottom ash basins at Belle River Power Plant  
21 with CCR Rule-compliant liner systems and closed the diversion basin by removing  
22 all ash from the basin. The removed ash was transported to and disposed of at the  
23 Range Road Landfill. Project construction was initiated and completed in 2023 for  
24 \$3.4 million. This project was required by the EPA's CCR Rule as discussed in  
25 Witness Lee's testimony.

Line  
No.

1 **Q42. Can you explain line 4 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

2 A42. Line 4 (Monroe Dry Fly Ash Conversion (ELG)) represents a project that converted  
3 the existing wet fly ash handling system at Monroe Power Plant to a dry system on  
4 all four Monroe Power Plant units. As noted earlier in my testimony, the EPA's fly  
5 ash ELG rule promulgated in 2015 required all liquid discharges to the environment  
6 from fly ash transport systems to cease by December 31, 2023. The Company's  
7 ELG rule compliance strategy is discussed in further detail in Company Witness  
8 Lee's direct testimony. Conversion to a dry fly ash handling system required  
9 installation of new equipment to pneumatically transport ash from each generating  
10 unit's precipitator to new storage silos. The project included installation of  
11 transport piping from the unit precipitator hoppers to the local unit silos and  
12 installation of transport piping from the local unit silos to two central storage silos.  
13 Blowers were installed to convey the fly ash to the respective ash silos.

14

15 In 2023, \$20.8 million was spent to tie-in new fly ash handling systems on Monroe  
16 Units 1 and 3 in Spring 2023 and Monroe Unit 4 in Fall 2023.

17

18 In 2024, \$2.6 million was spent for final site work, project demobilization, and  
19 performance testing. As required under the ELG Rule, the new fly ash handling  
20 systems were operational by the end of 2023.

21

22 **Q43. Can you explain lines 5 and 44 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

23 A43. Lines 5 and 44 (Monroe Bottom Ash Conversion (ELG)) represent a project to  
24 install an ELG-compliant bottom ash transport system that must be completed at  
25 Monroe Power Plant Units 1 and 2 by the December 31, 2025 EPA deadline. The



Line  
No.

1 Company's ELG rule compliance strategy is discussed in further detail in Company  
2 Witness Lee's direct testimony. The project scope includes removal of the wet  
3 bottom ash collection systems and major modifications to the boiler bottom hopper  
4 areas to permit installation of dry drag chain conveyor systems for ash removal.  
5 Project scope also includes the integration of the economizer ash handling systems  
6 into the dry fly ash handling systems utilizing dry flight conveyors. Once removed  
7 from the individual boilers, the bottom ash is moved outside the plant wall and into  
8 bunkers that function as the feed point for loading trucks with bottom ash to be sold  
9 or disposed of off-site. As required under the ELG Rule, all the new dry bottom  
10 ash and economizer ash handling systems on Monroe Units 1 and 2 will be  
11 operational by the end of 2025. This work is required to maintain environmental  
12 compliance and allow the units to continue to provide power for customer benefit.  
13 In accordance with the Commission's Order in the Company's 2022 IRP Case, and  
14 as discussed in further detail in Company Witness Uzenski's direct testimony,  
15 recovery of Monroe Power Plant capital investments on this project made after  
16 January 1, 2025 will be processed through a regulatory asset, shown on line 44 of  
17 Exhibit A-12, Schedule B5.1, page 2 of 9.

18

19 In 2023, \$11.7 million was spent to perform final engineering, bid project  
20 construction, and continue material procurement in support of the Unit 1 and Unit  
21 2 new bottom ash transport systems.

22

23 In 2024, \$32.1 million was spent to award the project construction contract and  
24 complete the installation of a common Unit 1-2 bunker and drag chain conveyor  
25 system. The new bottom ash handling system tie-in and connection to the new dry

Line  
No.

1 economizer ash transport system on Monroe Unit 2 was completed in a fall 2024  
2 outage.

3  
4 In 2025, \$11.0 million is projected to be spent for the new bottom ash handling  
5 systems that will be connected to Monroe Unit 1 in the fall. Additionally, the new  
6 economizer ash transport system will be connected on Monroe Unit 1 in the fall.

7  
8 In 2026, \$50 thousand is projected to be spent for project closeout activities  
9 including as-built drawings.

10

11 **Q44. Can you explain line 6 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

12 A44. Line 6 (Monroe FGD Wastewater (ELG)) represents a project to develop an ELG-  
13 compliant flue gas desulfurization (FGD) wastewater discharge treatment system  
14 at Monroe Power Plant. The Company's ELG rule compliance strategy is discussed  
15 in further detail in Company Witness Lee's direct testimony.

16

17 In 2023 and 2024, a combined \$0.6 million was spent to evaluate FGD ELG  
18 compliance technologies for Monroe Units 1 and 2. The Company will address and  
19 request future project expenditures in a future rate case.

20

21 **Q45. Can you explain lines 7-12 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

22 A45. Lines 7-12 (Site Security Projects and NERC Compliance Projects) represent  
23 projects required to improve power plant security. General site access security  
24 improvements as well as security enhancements for critical equipment are being  
25 implemented to mitigate security threats. In addition to physical security, North

Line  
No.

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 is required 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 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. Specific project site locations are not being provided but major work efforts, timelines, and expenditures are being provided as discussed below.

- Line 7 (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 2023, \$1.7 million was 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, \$7.9 million was spent to complete construction of the project. In 2025, \$0.4 million is projected to be spent for project completion and closeout.
- Line 8 (Site Security Project 18700) represents a completed project that installed badge card readers at a power plant. In 2023, \$52 thousand was

Line  
No.

1 spent on procuring badge readers and installation of the equipment to  
2 complete the project.

3 • Line 9 (Site Security Project 18906) represents a project to install a site  
4 entrance security building at a power plant. The Company spent \$0.7  
5 million in 2023 for engineering, design, and procurement of the security  
6 building and to begin concrete foundation construction. The Company  
7 spent \$1.5 million in 2024 to complete the installation of the security  
8 building and tie-in of building utilities. In 2025, \$71 thousand is projected  
9 to be spent for project completion and closeout.

10 • Line 10 (Site Security Project 20061) represents a completed project that  
11 installed a site security fence at a satellite property supporting power plant  
12 operations. Prior to the installation of the fence, there was no physical  
13 barrier to prevent trespassers from accessing the property. The Company  
14 spent \$0.2 million in 2023 to complete this work.

15 • Line 11 (NERC Compliance Project 18885) represents a completed project  
16 that installed a NERC-compliant perimeter fence at a power plant for \$1.0  
17 million in 2023. The need for the new fence was triggered by the recent  
18 retirement and decommissioning of a power plant which was previously  
19 providing site security within its protected area. \$1 thousand was spent in  
20 2024 to complete the project.

21 • Line 12 (NERC Compliance Project 19895) represents a completed project  
22 that restored a NERC-compliant perimeter fence in 2023 for \$7 thousand.

23

24 **Q46. Can you explain lines 13-15 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

Line  
No.

1 A46. Lines 13-15 (Sibley Quarry Landfill Modification (CCR), Sibley Quarry  
2 Infrastructure Modification (CCR), and Sibley Quarry Landfill Dewatering and  
3 Discharging Line) includes costs associated with site improvements required to  
4 allow safe and efficient acceptance of the significant quantities of coal combustion  
5 residuals (CCR) waste material that are being removed from Monroe Power Plant.  
6 Approximately 1 million cubic yards of bottom ash from the Monroe Power Plant  
7 inactive bottom ash basin were transported to Sibley Quarry to meet the EPA's  
8 CCR regulation. The improved system will continue to be used after the  
9 completion of the Monroe Bottom Ash Basin Closure (CCR) project for continuing  
10 waste disposal activities.

- 11 • Line 13 (Sibley Quarry Landfill Modification (CCR)) represents a project  
12 that installed a drain piping shaft (chimney drain) and created a new landfill  
13 operation fill plan. In 2023, \$1.8 million was spent to complete the project  
14 by installing a filtration system around the drain piping shaft and to relocate  
15 equipment to the current ash waste elevation. Approximately 23,000 cubic  
16 yards of material had to be moved so that stone could be placed for the  
17 chimney drain. Approximately 125,000 cubic yards of coarse aggregate  
18 limestone and approximately 40,000 cubic yards of crushed limestone was  
19 installed for the 18-ft diameter, 105-ft high chimney drain construction. The  
20 Company spent \$0.8 million in 2024 for additional piping/pump  
21 modifications to improve system reliability. In 2025, \$39 thousand is  
22 projected to be spent for final project closeout including final paperwork  
23 and as-built drawings. This project is required to allow continuing  
24 acceptance of bottom ash removed due to the closure of the Monroe bottom  
25 ash basin while continuing compliance with the provisions of Part 115,

Line  
No.

1 Solid Waste Management, of the Natural Resources and Environmental  
2 Protection Act, 1994 PA 451, as amended, and its Solid Waste Disposal  
3 Area Operating License number 9602.

4 • Line 14 (Sibley Quarry Infrastructure Modification (CCR)) represents a  
5 completed project that engineered and constructed a road, truck unloading  
6 pad, and temporary office to support the increasing levels of activity the site  
7 will experience in support of the Monroe ash removal tasks supporting CCR  
8 and ELG requirements. The Company spent \$9 thousand in 2023 for final  
9 project closeout costs.

10 • Line 15 (Sibley Quarry Landfill Dewatering and Discharging Line)  
11 represents a completed project that replaced a portion of the piping that  
12 transports accumulated ground water out of the Sibley Quarry to the Detroit  
13 River in compliance with its National Pollutant Discharge Elimination  
14 System (NPDES) permit. The replaced portion of pipe is approximately  
15 4,400 linear feet. The previous discharge piping was failing and required  
16 replacement. The Company spent \$32 thousand in 2023 for project closeout.

17

18 **Q47. Can you explain lines 18 and 45 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

19 A47. Line 18 (Monroe Bottom Ash Basin Closure (CCR)) represents a project that  
20 removed all bottom ash from the inactive bottom ash basin at Monroe Power Plant  
21 to meet the EPA's CCR regulation. This project included the removal of  
22 approximately 1 million cubic yards – equivalent to over 1 million tons – of bottom  
23 ash from the Monroe inactive bottom ash basin and its transportation to Sibley  
24 Quarry.

Line  
No.

1 The final EPA CCR Rule requires closure to be initiated as soon as technically  
2 feasible, but no later than April 11, 2021 and be completed within five years.  
3 Closure was initiated on October 21, 2020. Company Witness Lee describes the  
4 Company's closure plans for multiple CCR sites in further detail in his direct  
5 testimony. In accordance with the Company's 2022 IRP Order, and as discussed  
6 in further detail in Company Witness Uzenski's direct testimony, recovery of  
7 Monroe Power Plant investments on this project made after January 1, 2025 will be  
8 processed through a regulatory asset, shown on line 45 of Exhibit A-12, Schedule  
9 B5.1, page 2 of 9.

10

11 In 2023, \$14.4 million was spent to continue bottom ash material removal from the  
12 Monroe basin and its transportation to Sibley Quarry.

13

14 In 2024, \$9.4 million was spent to complete the bottom ash removal and  
15 transportation. The removal of all CCR from the Monroe bottom ash basin was  
16 completed in October of 2024.

17

18 In 2025, \$0.7 million is projected to be spent for final project closeout activities  
19 including closure certification.

20

21 **Q48. Can you explain lines 19 and 46 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

22 A48. Lines 19 and 46 (Monroe Fly Ash Basin Closure (CCR)) represent a project  
23 required by federal and state regulations. The existing Monroe Power Plant fly ash  
24 basin ceased operations December 29, 2023. It will be closed in place by  
25 dewatering the pond, grading the existing fly ash, and installing an impervious

Line  
No.

1 synthetic membrane cover. The existing fly ash basin utilizes a 400-acre pond with  
2 water depths up to 40 feet to contain approximately 28 million cubic yards of fly  
3 ash. In accordance with the Company's 2022 IRP Order, and as discussed in further  
4 detail in Company Witness Uzenski's direct testimony, recovery of Monroe Power  
5 Plant investments for this project made after January 1, 2025 will be through a  
6 regulatory asset, shown on line 46 of Exhibit A-12, Schedule B5.1, page 2 of 9.  
7 This project is required by the EPA's CCR Rule as discussed in Witness Lee's  
8 testimony.

9  
10 In 2023, \$3.8 million was spent to begin engineering and design. During 2023, the  
11 engineering and design contractor initiated the dewatering system design and  
12 capping plan, existing site documents were updated, field sampling of soils was  
13 performed, site topography was surveyed, and a site grading plan was established.  
14 Significant work effort was required to prepare the large number of permits  
15 required by various municipalities, agencies, and authorities including U.S. EPA,  
16 Michigan EGLE, Monroe County Drain Commission, Monroe County Road  
17 Commission, and Monroe Township. The operating plan license agreement for the  
18 basin closure project was prepared and filed with Michigan EGLE in 2023.

19  
20 In 2024, \$4.8 million was spent to continue engineering and design and develop a  
21 request for proposal to perform the basin closure. Engineering and design scope in  
22 2024 included fly ash basin dewatering and a water treatment system that complies  
23 with all applicable environmental limits. A dewatering pilot study was completed  
24 in the basin, demonstrating the characteristics of how the ash releases water, and  
25 the contents of the water. Additionally, the engineering and design contractor



Line  
No.

1 developed a Request for Proposal (RFP) to solicit bids from construction  
2 management firms for project execution. The RFP was issued in October 2024,  
3 bids were received in December 2024, and the final bidders are being evaluated.

4

5 In 2025, \$13.9 million is projected to award the ash basin closure construction  
6 contract and begin project construction, establish a trailer and staging area, begin  
7 procurement of a basin liner cap, and complete permit procurement.

8

9 In 2026, \$107.8 million is projected to be spent for on-site activities including  
10 dewatering the 410-acre pond, mass grading, material delivery, and liner cap and  
11 synthetic turf installation.

12

13 The Company plans to complete closure of the Monroe Fly Ash Basin by December  
14 28, 2028 to comply with the closure timeframes of 40 C.F.R. §257.102(f)(1) as  
15 discussed in Witness Lee's testimony.

16

17 **Q49. Can you explain line 20 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

18 A49. Line 20 (Legacy CCR Evaluation and Monitoring) represents a project to identify  
19 CCR Management Units (CCRMUs) and install groundwater monitoring wells at  
20 Sibley Quarry Landfill, Belle River, St. Clair, Delray, River Rouge, Trenton  
21 Channel, and Monroe Power Plants as discussed further in Witness Lee's direct  
22 testimony and as required by the EPA's Final 2024 Legacy CCR Rule. A CCRMU  
23 is an area of land on which CCR material has been received, placed, or is otherwise  
24 managed. This project will evaluate CCRMUs at the aforementioned sites to

Line  
No.

1 determine whether they are subject to groundwater monitoring, corrective action,  
2 closure, and post-closure care required by the EPA rule.

3  
4 In 2024, \$0.5 million was spent for engineering work including document reviews,  
5 site personnel interviews, and generating the initial field evaluation report, as well  
6 as taking initial boring samples.

7  
8 In 2025, \$2.3 million is projected to be spent to complete the field evaluation  
9 reports and to begin design and installation of monitoring wells.

10

11 In 2026, \$4.4 million is projected to be spent to complete installation of monitoring  
12 wells.

13

14 **Q50. Can you explain line 21 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

15 A50. Line 21 (St. Clair Bottom Ash Basin Closure (CCR)) represents a completed project  
16 that cleaned and closed the St. Clair Power Plant bottom ash basins by removal of  
17 all the CCR material, decontamination, disposal, and basin backfill. The St. Clair  
18 Power Plant bottom ash basins were subject to forced closure per the CCR Rule  
19 requiring them to cease receipt of waste and initiate closure as soon as technically  
20 feasible but by no later than April 11, 2021. As discussed in Witness Lee's  
21 testimony, the Company submitted a Part A Rule demonstration for the St. Clair  
22 Power Plant bottom ash basins, requesting an alternative closure deadline based on  
23 cessation of coal-fired generation operations in spring of 2022, and a commitment  
24 to complete closure of the basins by October 17, 2023. The Company initiated

Line  
No.

1 closure on September 1, 2022 and withdrew the requested approval for a Part A  
2 Rule demonstration.

3  
4 In 2023, \$0.4 million was spent on final project closure costs, including final  
5 disposal of bottom ash, final backfilling, and issuance of a closure report. Basin  
6 closure was completed in the first quarter of 2023.

7

8 **Q51. Can you explain lines 22-25 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

9 A51. Lines 22-25 detail steam plant removal costs associated with the retirement and  
10 decommissioning of power generation assets at River Rouge, St. Clair, and Trenton  
11 Channel Power Plants. Removal of retired steam generating units involves  
12 decommissioning, de-energization, decontamination, and demolition.  
13 Decommissioning and de-energization activities include the cost to air gap and  
14 isolate all unit systems and equipment to prepare them for removal from the site.  
15 This includes electrical, mechanical, plant controls, plant communication systems,  
16 plant fire systems, plant water and gas service shutdown, and plant electrical  
17 isolation from the bulk electric transmission system for incoming and outgoing  
18 power. Decontamination includes cleaning, washdown and disposal of hazardous  
19 and non-hazardous materials (including draining oils, chemicals, residual ash, coal  
20 dust, electronics and miscellaneous fluids), asbestos and lead abatement, cleaning  
21 tanks and pipelines, and removal of batteries and battery systems. Demolition  
22 includes tearing down buildings and remediating and removing the coal pile, ash  
23 and wastewater basins, and bulk chemicals.

Line  
No.

1 **Q52. Can you explain line 22 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

2 A52. Line 22 (River Rouge Decommissioning) is a project that supported achieving a  
3 cold, dark, and dry status by the end of 2024. The cold, dark, and dry status means  
4 that the facility does not require heat or power and all fluids have been removed  
5 from their respective tanks, reservoirs, and piping systems.

6  
7 In 2023, \$21.1 million was spent to start asbestos abatement, environmental clean-  
8 up, equipment removal, and continue electrical isolation of the power plant and site  
9 outbuildings.

10

11 In 2024, \$9.5 million was spent to complete electrical isolation of the power plant  
12 and outbuildings by end of second quarter of 2024 and establish a construction  
13 power feed for construction and various plant assets. Electrical isolation of the  
14 plant completed the process of making the plant cold, dark, and dry.

15

16 In 2025, \$1.2 million is projected to be spent to perform chimney stack inspections,  
17 clean oily waste lines, and complete other environmental work.

18

19 The Company will address River Rouge Power Plant demolition expenditures in a  
20 future rate case.

21

22 **Q53. Can you explain line 23 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

23 A53. Line 23 (St. Clair Decommissioning) is a project to decommission St. Clair Power  
24 Plant, which was in operation for approximately 70 years. Due to the fact that coal  
25 handling equipment, boat unloading, firefighting, and control systems located on

Line  
No.

1 St. Clair property and within the St. Clair Power Plant proper must be kept in-  
2 service until Belle River Power Plant ceases coal-fired operations at the end of  
3 2026, the project will be performed in two phases. The project scope discussed  
4 below is associated with the first phase to achieve a cold, dark, and dry status.

5

6 In 2023, \$21.7 million was spent to continue work to achieve a cold and dry state  
7 in the plant and start asbestos abatement. Environmental clean-up and equipment  
8 removal in exterior outbuildings along with their demolition were initiated. All  
9 basins were emptied, cleaned, and filled in 2023.

10

11 In 2024, \$13.2 million was spent for work on electrical isolation of the plant from  
12 the electrical grid and continued abatement and demolition of exterior outbuildings,  
13 namely structures associated with cooling water outfalls.

14

15 In 2025, \$1.1 million is projected to be spent to finalize electrical isolation and for  
16 as-built drawings required to prepare the St. Clair Power Plant demolition bid  
17 package. Completion of the electrical isolation work will place the plant in a dark  
18 state, completing all cold, dark, and dry scope.

19

20 The Company will address St. Clair Power Plant demolition expenditures in a future  
21 rate case.

22

23 **Q54. Can you explain line 24 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

24 A54. Line 24 (Trenton Channel Decommissioning) is a project to fully decommission  
25 and remove all plant structures including waste products from the Trenton Channel

Line  
No.

1 Power Plant site that produced power for approximately 100 years prior to its  
2 retirement.

3  
4 In 2023, \$51.5 million was spent to continue decommissioning efforts. Work  
5 completed in 2023 included awarding the demolition contract, initiation of asbestos  
6 abatement and environmental clean-up. Equipment removal in plant outbuildings  
7 along with their demolition and the plant's electrical isolation was initiated.  
8 Electrical isolation of the plant was completed, and the plant reached a cold, dark,  
9 and dry state.

10

11 In 2024, \$36.5 million was spent to complete asbestos abatement, remove  
12 equipment inside the plant, and demolish stacks and the main turbine house. The  
13 stacks were demolished in May 2024 and the main turbine house was demolished  
14 in June 2024. The Company also began final site grading and soil remediation  
15 activities.

16

17 In 2025, \$7.5 million is projected to be spent to conclude soil remediation and final  
18 site grading. Performing these activities in the second quarter of 2025 will  
19 complete the decommissioning process.

20

21 **Q55. Can you explain line 25 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

22 A55. Line 25 (Trenton Channel Sea Wall) represents a project to restore the integrity of  
23 the seawall at the Trenton Channel Power Plant and to install a pedestrian greenway  
24 path along the Detroit River while also meeting the permitting requirements of the  
25 US Army Corps of Engineers, Michigan EGLE, and the City of Trenton. The work

Line  
No.

1 includes removal of deteriorated sheet piles, maintenance of existing piles and  
2 installation of new piles along the Detroit River and Slocum Canal shorelines.  
3 Without this work, the shoreline is at risk for sloughing into and contaminating the  
4 Detroit River and Slocum Canal. Development of the pedestrian greenway path  
5 was stipulated in the city-approved demolition permit and will be installed along  
6 the Detroit River riverfront after the power plant is demolished and site grading is  
7 finalized.

8  
9 From 2023 to the beginning of 2025, \$0.9 million was spent to begin engineering  
10 and design of the seawall, natural shoreline, and greenway path.

11  
12 In 2026, \$9.5 million is projected to be spent to complete engineering, design, and  
13 construction of the seawall for the riverfront and canal and complete engineering  
14 and design of the greenway path.

15

16 **Q56. Can you explain line 29 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

17 A56. Line 29 (Ludington Upgrades) represents an efficiency upgrade project at the  
18 Ludington Pumped Storage Facility that was managed by Consumers Energy,  
19 Ludington's majority owner. The expenditures represent DTE Electric's 49 percent  
20 share of project costs. The upgrades of the six Ludington generating units began in  
21 2013 and finished with Ludington Unit 3 in 2022. A combined \$1.2 million was  
22 spent in 2023 and 2024 for project closeout and demobilization.

Line  
No.

1   **Q57. Can you explain line 32 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

2   A57. Line 32 (Blue Water Energy Center (CCGT)) represents a project that built a 1,127  
3       net MW (summer-rated capacity) efficient baseload CCGT generating plant on 40  
4       acres of Company property adjacent to the existing Belle River Power Plant. This  
5       location was strategically selected due to its proximity to transmission lines and  
6       high-pressure natural gas pipeline infrastructure. The plant completed construction  
7       and became commercially operational in June of 2022.

8  
9       In 2023, the Company recorded a net credit to the project in the amount of \$4.6  
10      million, primarily driven by a \$1.4 million credit for a refund from International  
11      Transmission Company (ITC) that was higher than anticipated due to an interest  
12      rebate and a \$3.2 million credit for a Canadian tax refund on natural gas purchased  
13      to support startup testing.

14  
15      In 2024, \$0.3 million was spent for project closeout activities.

16  
17      In 2025, \$6 million is projected to be spent in the final milestone payment to Kiewit.

18  
19      The Company currently forecasts total project capital expenditures of \$946.8  
20      million, which is below the \$951.8 million approved by the Commission in the  
21      April 27, 2018 Order in Case No. U-18419. This represents an outstanding  
22      outcome, especially given the fact the project was constructed in the midst of the  
23      COVID-19 pandemic.



Line  
No.

1 **Q58. Can you explain line 33 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

2 A58. Line 33 (BWEC Transmission Upgrades) represents transmission upgrades (the  
3 Benton Harbor transformer project) required for BWEC to acquire MISO generator  
4 interconnection rights. Since necessary transmission network upgrades were not  
5 included in the \$951.8 million for the construction of BWEC in MPSC Case No.  
6 U-18419, this project is distinct from line 32 (Blue Water Energy Center (CCGT)).

7  
8 In 2023, a refund of \$4.8 million was credited back against the \$9 million paid in  
9 2021 for the Benton Harbor transformer project. This credit was received after new  
10 generating projects completed by other companies requested rights to and  
11 compensated the Company for utilizing part of the grid transmission capabilities  
12 previously funded by the Company through this project.

13  
14 **Q59. Can you explain line 34-36 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

15 A59. Lines 34-36 (Blackstart Projects 10570 & 20255, 17611, and 18320) represent  
16 projects that support the North American Electric Reliability Corporation (NERC)  
17 black start plan as administered by ITC in our region. Each region designates  
18 certain generating plants as black start units. A black start unit is one that can  
19 startup utilizing only its own internal power without support from the grid in the  
20 event of a major grid blackout, such as the 2003 blackout. This capability is  
21 required to restart the grid following a blackout. In the Company's 2024 rate case,  
22 Case No. U-21534, ITC explained, "Each Transmission Operator ("TOP") is  
23 required to have an SRP [system restoration plan] under NERC standards.  
24 Blackstart resources are a key component to a TOP's SRP."<sup>2</sup> ITC further cautioned

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<sup>2</sup> Case No. U-21534 Transcript 6 Tr 4753

Line  
No.

1 that black start resources are being lost through conventional generation retirements  
2 and that the Company's investments in the black start resources will ensure a  
3 reliable and resilient SRP. As is common in the industry, the black start unit project  
4 details disclosed in publicly accessible regulatory filings are limited in order to  
5 maintain the security of these critical sites. ITC echoed this need for limited  
6 disclosure in the prior rate case, explaining, "DTE has provided the parties to this  
7 case with the information it is able to disclose without compromising the security  
8 of the electric grid or violating its other obligations to maintain the confidentiality  
9 of these documents. The Commission should remain consistent with its position in  
10 U-21297 that no further disclosure of information regarding the Blackstart Projects  
11 is appropriate."<sup>3</sup> The Commission was persuaded of the importance of these  
12 projects in maintaining grid security in their Final Order dated January 23, 2025<sup>4</sup>,  
13 in Case No U-21534. Project major work efforts, timelines, and expenditures are  
14 discussed in detail below.

- 15  
16 • Line 34 (Blackstart Project 10570 & 20255) represents a completed project  
17 that provided fuel and controls systems capabilities to enable a peaker site  
18 to start up without power from the grid.

19  
20 In 2023, \$10.1 million was spent to complete the fuel system modifications  
21 and testing and to install major electrical components.

---

<sup>3</sup> Case U-21534 Transcript 6 Tr 4758

<sup>4</sup> Case No. U-21534 January 23, 2025 Order, page 48

Line  
No.

1 In 2024, \$2.4 million was spent to complete all construction activities,  
2 commission the installed equipment, and perform final project closeout  
3 activities including drawing updates.

4

- 5 • Line 35 (Blackstart Project 17611) represents a project that fulfills a portion  
6 of the requirements of the ITC SRP by providing an existing site with new  
7 equipment and controls that enable the peaker site to start up without power  
8 from the grid.

9

10 In 2023, \$2.0 million was spent to bid and procure switchgear, two  
11 generators, and to complete engineering efforts.

12

13 In 2024, \$3.3 million was spent to complete all construction activities.

14

15 In 2025, \$0.4 million is projected to be spent to commission the installed  
16 equipment.

17

- 18 • Line 36 (Blackstart Project 18320) represents a project that provides an  
19 existing site with new equipment and controls that enable the peaker site to  
20 start up without power from the grid.

21

22 In 2023, \$3.0 million was spent to bid and award equipment installation,  
23 receive project materials, perform the equipment installation, and  
24 commission the installed equipment. This allowed the unit to return to  
25 service until final long lead material was received in 2024.

Line  
No.

1 In 2024, \$0.8 million was spent to receive the final long lead transfer switch  
2 and complete equipment installation.

3  
4 In 2025, \$0.1 million is projected to be spent for final project  
5 commissioning and closeout.

6

7 **Q60. Can you explain line 37 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

8 A60. Line 37 (Slocum Battery Pilot) represents a project to replace the diesel-fueled  
9 peakers at the Company's Slocum peaker site located in the City of Trenton with a  
10 14 MW / 56 MWhr lithium-ion (Li-ion) BESS. The BESS will store excess energy  
11 that is generated on the grid during off-peak hours. This energy will then be  
12 available for dispatch during higher-priced peak hours.

13

14 In 2023, \$10.1 million was spent to finish engineering, continue the procurement  
15 of materials, complete the construction bid package, issue an RFP, and award the  
16 construction contract. Additionally, the existing diesel peakers and their supporting  
17 equipment were decommissioned and removed from the site.

18

19 In 2024, \$26.3 million was spent to complete BESS installation.

20

21 In 2025, \$0.7 million is projected to be spent for final project closeout costs.

22

23 The Slocum Battery Pilot started commercial operations in February 2025.

Line  
No.

1 **Q61. Can you explain line 38 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

2 A61. Line 38 (Trenton Channel Energy Center BESS) represents a project to construct a  
3 220 MW / 880 MWhr Li-ion BESS build, consistent with the build plan approved  
4 by the Commission in their Order in the Company's 2022 IRP Settlement  
5 Agreement and the Company's goal of net zero by 2050. This project demonstrates  
6 progress towards the Company's and State's energy storage target<sup>5</sup>. The forecast  
7 includes the expenditures needed for engineering and long lead material  
8 procurement to support a 220 MW BESS starting commercial operations in 2026.

9  
10 In 2023, \$5.3 million was spent to bid equipment and award a contract, and procure  
11 long lead materials (i.e., electrical breakers and transformer).

12  
13 In 2024, \$103.0 million was spent to take delivery of major electrical equipment  
14 and begin site preparation and construction in the fourth quarter of 2024.

15  
16 In 2025, \$260.1 million is projected to be spent to take delivery of batteries and  
17 electrical collection equipment for the battery inverters and complete construction  
18 of the substation and BESS electrical switchyard.

19  
20 In 2026, \$41.4 million is expected to be spent on final payments, commissioning,  
21 performance testing, and capacity testing for the entire site.

---

<sup>5</sup> Sections 101 and 103, MCL 460.1101(1)-(9) establish a statewide energy storage target of 2,500 megawatts (MW)

Line  
No.

1 **Q62. Can you explain line 39 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

2 A62. Line 39 (Northeast 11-1 Decommissioning) represents a project to decommission  
3 the Northeast 11-1 peaker unit that retired in 2023.

4

5 In 2023, \$0.2 million was spent to electrically disconnect the peaker from the  
6 electrical grid, drain lube oil from the peaker, and begin engineering of the  
7 decommissioning project. Engineering work included environmental protections,  
8 isolation of fuel source, disabling of the fire protection system, and plant controls  
9 systems modifications.

10

11 In 2024, \$0.1 million was spent to complete engineering of the decommissioning  
12 phase of the project.

13

14 In 2025, \$0.4 million is projected to be spent to separate the peaker from those  
15 remaining active at the site.

16

17 **Energy Supply's Routine Capital Investments**

18 **Q63. What information is provided on page 3 of Exhibit A-12, Schedule B5.1?**

19 A63. Page 3 provides a summary of the routine capital expenditures for steam power,  
20 hydraulic power (Ludington), and other power generation facilities from the  
21 beginning of 2023 through December 31, 2026, broken down by site and by major  
22 investment category. Routine capital projects include projects to maintain plant  
23 reliability, maintain environmental compliance, provide safe operation of  
24 equipment, and improve efficiency, all with a focus on providing the customer  
25 generation that balances, among other things, reliability and cost. The Company

Line  
No.

1 has included all Monroe routine 2025-2026 expenditures in a regulatory asset  
2 shown on Exhibit A-12, Schedule B5.1, page 3, line 12, consistent with the  
3 Commission's final Order in the Company's 2022 IRP Settlement Agreement, Case  
4 No. U-21193.

5 **Energy Supply's Routine Capital Expenditures - Steam Power Generation**

6 **Q64. What were the Company's routine capital expenditures completed in 2023 for**  
7 **Steam Power Generation?**

8 A64. During 2023, the Company's Energy Supply group routine capital expenditures  
9 related to Steam Power Generation were \$213.3 million as shown on Exhibit A-12,  
10 Schedule B5.1, page 3 of 9, line 6, column (b). These expenditures included the  
11 following projects that individually exceeded \$1 million as detailed on page 4 of  
12 Exhibit A-12, Schedule B5.1:

- 13 • In preparation for the Belle River Unit 2 2024 periodic outage, Belle River  
14 Unit 2 LP turbine rotor and blade materials were purchased for \$5.9 million  
15 (Exhibit A-12, Schedule B5.1, page 4, line 1). Inspections in the past had  
16 identified blade erosion and rotor cracking issues that needed to be addressed  
17 to ensure continued safe and reliable operation of the LP turbines. This work  
18 was a permanent fix to the damage identified in 2020. Additionally, \$2.4  
19 million was spent to procure materials to replace the Belle River Unit 2  
20 exciter (Exhibit A-12, Schedule B5.1, page 4, line 2). Vibration levels  
21 indicated structural/mechanical integrity issues with the rotors.  
22 Replacement of the exciter provides future equipment reliability. Finally,  
23 waterwall tube materials were procured for \$1.7 million (Exhibit A-12,  
24 Schedule B5.1, page 4, line 3). The project replaced 2,300 square feet of

Line  
No.

- 1 boiler waterwall panels damaged by quench cracking and soot blower  
2 erosion and was required to support continued reliable boiler operation.
- 3 • \$3.1 million was spent to finish isolating St. Clair Power Plant from the fuel  
4 supply system required to continue to support Belle River Power Plant  
5 (Exhibit A-12, Schedule B5.1, page 4, line 4). There were systems in the St.  
6 Clair Fuel Supply system that were common to both plants. Although St.  
7 Clair Power Plant retired in 2022, these common systems must remain  
8 functional to fuel the Belle River Power Plant. The scope of the work to  
9 separate the Belle River and St Clair fuel supply systems was extensive and  
10 included modifications to the fire protection, general service water,  
11 wastewater, stormwater, and low and medium voltage electrical switchgear  
12 systems.
- 13 • Installation of a wet dust collector replacing three (3) dry-type dust collectors  
14 in the Belle River fuel supply 3TH-9 building was completed for \$1.7  
15 million (Exhibit A-12, Schedule B5.1, page 4, line 5). The new dust  
16 collector mitigates combustible dust and meets National Fire Protection  
17 Association (NFPA) guidelines.
- 18 • In preparation for the Greenwood Unit 1 2025 periodic outage, \$5.8 million  
19 was spent on progress payments for procurement of new LP turbine rotors  
20 and blades (Exhibit A-12, Schedule B5.1, page 4, line 6). Stress corrosion  
21 cracking of multiple blade root connections needed to be repaired/replaced  
22 to provide continued safe and reliable operation of the LP turbines.
- 23 • Monroe Unit 1 waterwall tube replacements were completed for \$15.0  
24 million (Exhibit A-12, Schedule B5.1, page 4, line 7). The project replaced



Line  
No.

- 1 2,500 square feet of boiler waterwall tubes that were deteriorated due to  
2 corrosion fatigue, fireside corrosion, and tube thinning.
- 3 • Monroe Unit 1 LP turbine rotors and blades were replaced addressing the  
4 industry-wide stress corrosion cracking and resultant safety concerns  
5 common on LP turbines for \$10.4 million (Exhibit A-12, Schedule B5.1,  
6 page 4, line 8). Additionally, prior inspections revealed the expected  
7 ordinary erosion wear and tear on blade rows that needed to be addressed.  
8 The rotors removed were refurbished for use in the Monroe Unit 4 LP  
9 turbines in 2025 to minimize the project cost needed to address stress  
10 corrosion cracking on its LP turbine rotors.
  - 11 • Monroe Unit 1 reheat outlet pendants were replaced for \$5.4 million (Exhibit  
12 A-12, Schedule B5.1, page 4, line 9). The boiler reheater tubes are critical  
13 to steam turbine design and operations. Reheater tubes allow exhaust steam  
14 from the HP turbine to be reheated in the boiler and reintroduced into the IP  
15 and LP turbines with additional energy that adds to unit MW output at  
16 improved efficiency levels. The replacements were based on near term tube  
17 failure risk which would force the unit offline for repair.
  - 18 • Thirty-six (36) expansion joints were replaced on Monroe Unit 1 for \$5.3  
19 million (Exhibit A-12, Schedule B5.1, page 4, line 10). Expansion joints in  
20 the air duct and flue gas systems accommodate thermal expansion of the  
21 process ductwork and are being repaired to address flue gas leakage. Scope  
22 of work included ash removal and scaffolding to provide a safe workspace,  
23 confined space rescue services, lead/asbestos abatement, and replacement of  
24 the expansion joints. The replacements were based on near term failure risk

Line  
No.

- 1 which would affect unit reliability, efficiency, and result in a safety risk to  
2 plant personnel.
- 3 • \$4.2 million was spent to complete the replacement of the Monroe Unit 1  
4 coal mill primary air ductwork (Exhibit A-12, Schedule B5.1, page 4, line  
5 11). The previous ductwork had thinned, resulting in fugitive dust leaks, and  
6 required replacement.
- 7 • \$3.9 million was spent to procure and replace blade rows 1, 3, and 8 on the  
8 Monroe Unit 1 HP turbine (Exhibit A-12, Schedule B5.1, page 4, line 12).  
9 The turbine blades were replaced due to solid particle erosion. The  
10 replacement was required to sustain the HP turbine reliability.
- 11 • Monroe Unit 1 IP turbine row 1 blades (Exhibit A-12, Schedule B5.1, page  
12 4, line 13) were replaced for \$3.7 million. The first stage rows on both ends  
13 (turbine-end and generator-end) were replaced due to solid particle erosion.  
14 The replacement was required to sustain the IP turbine reliability.
- 15 • Monroe Unit 1 SCR catalyst modules for layers 1, 2, and 4 were replaced for  
16 \$3.3 million (Exhibit A-12, Schedule B5.1, page 4, line 14). The catalyst  
17 module replacements were required to maintain compliance with air permit  
18 emission limits for NOx and ammonia slip guidelines.
- 19 • Monroe Unit 1 IP turbine rotor project (Exhibit A-12, Schedule B5.1, page  
20 4, line 15) started progress payments of \$2.6 million to replace the rotor in  
21 2025. During off-site inspection in 2023, creep void indications of cracking  
22 were found in the rotor bore and the stage 1 wheel dovetail roots. The OEM  
23 performed the work required to return the IP rotor to service on a short-term  
24 basis but also provided further analysis of the rotor that confirmed the need

Line  
No.

1 to replace the rotor soon, concluding that it could only be safely operated for  
2 an additional 30 months.

3 • Monroe Unit 1 economizer tubes were replaced for \$2.5 million (Exhibit A-  
4 12, Schedule B5.1, page 4, line 16). The boiler economizers are a critical  
5 component of the boiler tubing circuits that removes waste heat from the  
6 combustion process and utilizes it to preheat boiler feedwater improving  
7 overall cycle efficiency and heat rate. The original equipment economizer  
8 had erosion and tube thinning which required approximately 2,000 linear  
9 feet of tubing replacements to maintain boiler reliability.

10 • The Monroe Unit 1 reheat turbine stop valves (Exhibit A-12, Schedule B5.1,  
11 page 4, line 17), control valves (Exhibit A-12, Schedule B5.1, page 4, line  
12 20), and main steam stop valves (Exhibit A-12, Schedule B5.1, page 4, line  
13 21) were rebuilt for \$2.4 million, \$1.3 million, and \$1.3 million,  
14 respectively. All turbine valves must operate properly to provide overspeed  
15 protection for the turbine and prevent possible catastrophic failure.

16 • Monroe Unit 1 SCR inlet and outlet dampers were removed for \$1.5 million  
17 (Exhibit A-12, Schedule B5.1, page 4, line 18). When the SCR was  
18 originally installed, these dampers and the SCR only operated during  
19 summer months. Now, since the SCR is operated year-round due to changes  
20 in EPA regulations, the inlet and outlet dampers are not needed and  
21 contribute to draft losses leading to ID fan limitations, negatively affecting  
22 the output capability of the generating unit.

23 • The Monroe Unit 1 south air heater hot and cold end baskets were replaced  
24 for \$1.4 million (Exhibit A-12, Schedule B5.1, page 4, line 19). The  
25 previous baskets were degraded due to corrosion and, if not addressed,

Line  
No.

- 1 would have become loose and caused an imbalance leading to an air heater  
2 drivetrain failure. The replacements restored physical integrity and heat  
3 transfer efficiency of the air heater.
- 4 • Monroe Unit 1 coal mill silo 1-3 (Exhibit A-12, Schedule B5.1, page 4, line  
5 22) and Monroe Unit 4 coal mill silo 4-1 (Exhibit A-12, Schedule B5.1, page  
6 4, line 38) were rebuilt for \$1.2 million and \$1.1 million, respectively. The  
7 chemical and abrasive properties of coal within the silos resulted in corrosion  
8 and erosion of the silo walls and compromised the structural integrity,  
9 requiring repairs.
  - 10 • Monroe Unit 1 turning gear and bull gear were rebuilt for \$1.2 million  
11 (Exhibit A-12, Schedule B5.1, page 4, line 23). The turbine turning gear  
12 must engage to the bull gear as designed to rotate the turbine shaft properly  
13 when the unit is offline to prevent damage to the turbine shaft. To address  
14 the excessive wear on these components, the turning gear was overhauled  
15 and the bull gear was replaced.
  - 16 • Monroe Unit 1 FGD mist eliminators (1<sup>st</sup> and 2<sup>nd</sup> stages) were replaced for  
17 \$1.1 million (Exhibit A-12, Schedule B5.1, page 4, line 24). The original  
18 mist eliminator trays were plugged, damaged, and worn. They were replaced  
19 to improve FGD moisture removal and emission monitoring equipment  
20 reliability and accuracy.
  - 21 • \$1.1 million was spent to replace the Monroe Unit 1 FGD absorber inlet  
22 expansion joint and flanges on both upstream and downstream sides of the  
23 joint (Exhibit A-12, Schedule B5.1, page 4, line 25). The inlet expansion  
24 joint is essential for inlet flue gas to reliably enter the absorber tower. It  
25 allows for expansion and contraction of the inlet duct with changing

Line  
No.

1 temperatures (during a shutdown/startup of the unit). The previous  
2 expansion joint was deteriorated and showed visible signs of failure. Failure  
3 of this expansion joint will result in flue gas leaking from the ductwork and  
4 poses a reliability risk.

- 5 • The Monroe Unit 1 north and south FGD booster fans were rebuilt for \$1.1  
6 million (Exhibit A-12, Schedule B5.1, page 4, line 26). The FGD system for  
7 each unit includes a north and south booster fan. These axial fans, with a  
8 14-foot diameter impeller, are located between the outlet of the precipitator  
9 and the inlet to the FGD Absorber. Failure of one of these booster fans  
10 would cause the unit to be limited to half load until replacement parts could  
11 be procured and installed. Due to the corrosive environment in which these  
12 fans operate, the fans require repair or replacement of the hub and blades  
13 every 8 years to maintain reliability. This maintenance was due in 2023.
- 14 • \$1.2 million was spent to start procurement of materials in preparation to  
15 replace the Monroe Unit 2 air heater cold end baskets (Exhibit A-12,  
16 Schedule B5.1, page 4, line 27) in 2024. The air heater plays a critical heat  
17 transfer role to boiler efficiency and flue gas equipment operational  
18 performance. The Monroe units cold end baskets typically last 7-10 years.  
19 The cold-end baskets on Monroe Unit 2 north and south air heaters had been  
20 in service since 2014 and were in failure mode due to a significant loss (30  
21 percent) of element material. As this condition progresses, so does the risk  
22 of an out of balance condition, placing high stresses on all components of  
23 the air heater. The imbalance issue will lead to drive train failures, resulting  
24 in unit forced outages.

Line  
No.

- 1           • \$1.2 million was spent to start procurement of SCR catalyst modules for  
2           layer 3 on Monroe Unit 2 that were replaced in 2024 (Exhibit A-12, Schedule  
3           B5.1, page 4, line 28). The catalyst module replacements are required to  
4           maintain compliance with air permit emission limits for NOx and ammonia  
5           slip guidelines.
- 6           • In preparation for the Monroe Unit 3 outage in 2024, SCR catalyst modules  
7           for layers 2, 3, and 4 were procured for \$5.1 million (Exhibit A-12, Schedule  
8           B5.1, page 4, line 29). The catalyst module replacements were required to  
9           maintain compliance with air permit emission limits for NOx and ammonia  
10          slip guidelines. Additionally, new air heater cold end baskets were  
11          purchased for \$2.2 million (Exhibit A-12, Schedule B5.1, page 4, line 30).  
12          The previous cold-end baskets on Monroe Unit 3 north and south air heaters  
13          were in service since 2015 and were in failure mode due to a significant loss  
14          (30 percent) of element material. \$1.4 million was spent to start engineering  
15          and procure material to replace twelve (12) Monroe Unit 3 expansion joints  
16          (Exhibit A-12, Schedule B5.1, page 4, line 31). The replacements were  
17          required to maintain unit reliability and efficiency, while also mitigating  
18          safety risks to plant personnel. Finally, \$1.0 million was spent to start  
19          engineering and begin to procure materials to replace the Monroe Unit 3  
20          existing coal mill primary air ductwork (Exhibit A-12, Schedule B5.1, page  
21          4, line 33). The previous ductwork was thinning, causing fugitive dust leaks,  
22          and required replacement.
- 23          • Monroe Unit 3 coal mill 3-6 overhaul was completed for \$1.3 million  
24          (Exhibit A-12, Schedule B5.1, page 4, line 32). The coal mill overhaul was  
25          due based on service hours, air flow performance, and lube oil analysis

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- 1 indications of deteriorating internal components. Due to the abrasiveness of  
2 coal, coal mill parts experience significant wear in the process of converting  
3 lump coal to a fine powder consistency suitable for boiler combustion and  
4 need to be disassembled, repaired, and components replaced approximately  
5 every 10 years.
- 6 • In preparation for the Monroe Unit 4 2025 periodic outage, \$4.3 million was  
7 spent to start procurement of long lead materials related to refurbishment of  
8 the LP turbines (Exhibit A-12, Schedule B5.1, page 4, line 34).  
9 Refurbishment is needed due to the industry-wide problem of stress  
10 corrosion cracking on the current LP turbine. The rotors replaced on Monroe  
11 Unit 1 in 2023 are being refurbished and installed on Monroe Unit 4 to keep  
12 the project cost to a minimum while mitigating the safety risk of a stress  
13 corrosion cracking catastrophic failure. Additionally, \$3.6 million was spent  
14 to start engineering and material procurement of SCR catalyst module layers  
15 1, 3, and 4 that will be replaced (Exhibit A-12, Schedule B5.1, page 4, line  
16 35). The catalyst module replacements are required to maintain compliance  
17 with air permit emission limits for NOx and ammonia slip guidelines.
  - 18 • Installation of SCR catalyst modules for layer 2 for Monroe Unit 4 was  
19 completed for \$1.9 million (Exhibit A-12, Schedule B5.1, page 4, line 36).  
20 The catalyst module replacements were required to maintain compliance  
21 with air permit emission limits for NOx and ammonia slip guidelines.
  - 22 • Monroe Unit 4 south boiler feed pump turbine condenser retubing was  
23 completed for \$1.4 million (Exhibit A-12, Schedule B5.1, page 4, line 37).  
24 A significant increase in tube failures in the condenser were identified,  
25 raising to thirty-nine (39) percent the condenser tubes plugged. The

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1 condenser required retubing to condense the steam and keep the boiler feed  
2 pump turbine in service.

3 • Procurement of a spare main unit transformer was completed for \$3.0  
4 million to replace the transformer that was installed on Monroe Unit 1 in the  
5 fall of 2021 (Exhibit A-12, Schedule B5.1, page 4, line 39). This transformer  
6 is needed for fleet reliability in the event of a failure of one of the other main  
7 unit transformers.

8 • Monroe underground storage tank No. 389 (Exhibit A-12, Schedule B5.1,  
9 page 4, line 40) was removed and replaced with an above-ground storage  
10 tank for \$1.9 million. The tank collects used oil, is constructed of double-  
11 walled steel, and has a capacity of 20,000 gallons. The previous tank had  
12 been in service since 1993. This project mitigates the oil spill risk and  
13 sustains continuing environmental compliance.

14 • The Monroe inlet canal skimmer was replaced for \$1.0 million (Exhibit A-  
15 12, Schedule B5.1, page 4, line 41). The previous skimmer had failed due  
16 to icing and material build up on the river pushing against the skimmer. The  
17 equipment skims the surface of the water preventing material from entering  
18 the plant water intake.

19 • The Monroe fuel supply coal pile runoff oil wastewater system replacement  
20 project continued with construction at a cost of \$3.7 million (Exhibit A-12,  
21 Schedule B5.1, page 4, line 42). This project enhanced environmental  
22 compliance by reducing the risk of oil contaminants from the storm water  
23 and coal pile run-off systems reaching the lake.



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1 In 2017 the plant experienced a Notice of Violation on a similar system.  
2 Remediation of soil and augmentations to the wastewater system were  
3 required following the event. Further review of oil-containing equipment on  
4 the Monroe property identified that the areas around the coal pile run-off  
5 system are at risk of a similar event. A major oil spill event into public  
6 waterways could potentially result in significant cleanup costs as well as  
7 fines for not mitigating this potential risk.

8  
9 The previous coal pile run-off wastewater treatment system has no oil  
10 removal capabilities to prevent oil discharges into open waters. The coal  
11 pile containment area contains over 30,000 gallons of oil stored in various  
12 locations. Any loss of oil from these systems could migrate to the coal pile  
13 run-off water collection system.

14  
15 Previously, discovery of oil-contaminated water in the coal pile run-off  
16 wastewater system required an operator to be at the right place at the right  
17 time. Detecting small quantities of oil sheen is very difficult and heavily  
18 influenced by environmental conditions, including daylight, rain, fog, etc.  
19 Once the operator discovered that the contamination existed, they manually  
20 intervened by deploying oil-containment booms and contracting  
21 environmental clean-up firms to mitigate the event.

22  
23 The completed project installed an oily waste treatment system that has  
24 automated oil removal capabilities for the coal pile run-off system. The new  
25 system does not depend on visual observations and manual intervention to

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No.

1 trigger an oil clean-up response. Instead, the oily waste treatment system  
2 provides 24x7 enhanced environmental protection.

3

4 • Monroe fuel supply tripper car gallery B floor replacement (8,096 square  
5 feet of elevated structure) was completed for \$3.0 million (Exhibit A-12,  
6 Schedule B5.1, page 4, line 43). The original tripper gallery floors,  
7 supporting floor beams, and floor beam top flanges had corroded over time  
8 and required replacement to ensure worker safety during washdown  
9 activities required to control fugitive and combustible coal dust. There are  
10 9 (nine) galleries (sections) in the tripper gallery that serve all four Monroe  
11 Power Plant units, designated by letters A, B, C, D, E, F, G, H, and J. Floor  
12 beam inspections were conducted to determine the condition of the gallery  
13 and prioritize sections based on the results. The inspection included the  
14 gallery conveyor floor system, floor plates, and floor supporting structural  
15 steel. Gallery B was identified as a priority area in the inspection. Support  
16 beams and girders showed signs of degradation and needed to be replaced.  
17 This project restored the structural integrity of the floor, the floor beams,  
18 girders, and associated connection hardware for this gallery section.

19

20 • Monroe fuel supply transfer chute that feeds from conveyor C4 to conveyors  
21 C5 and C5A was replaced for \$2.2 million (Exhibit A-12, Schedule B5.1,  
22 page 4, line 44), the transfer chutes from conveyors C10, C11, and C5 that  
23 feed onto conveyor C4 were replaced for \$2.0 million (Exhibit A-12,  
24 Schedule B5.1, page 4, line 45), and the transfer chute from conveyor C19  
25 that feeds onto conveyor C10 was replaced for \$1.2 million (Exhibit A-12,

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1 Schedule B5.1, page 4, line 47). Transfer chutes are used throughout the  
2 fuel supply system to direct coal from one conveyor belt to another on the  
3 path from the coal piles to the powerhouse. The previous chutes tended to  
4 generate significant amounts of coal dust during periods of dry coal and were  
5 prone to pluggage during periods of wet coal. The new discharge chute  
6 technology minimizes combustible dust and coal spillage and maintains  
7 compliance with NFPA guidelines.  
8

- 9 • In preparation for the Monroe fuel supply tripper car gallery C floor (Exhibit  
10 A-12, Schedule B5.1, page 4, line 46) being replaced in 2024, \$1.7 million  
11 was spent for engineering and materials (10,750 square feet of elevated  
12 structure). The original tripper gallery floor, supporting floor beams, and  
13 floor beam top flanges had corroded over time and require replacement to  
14 ensure worker safety during washdown activities required to control fugitive  
15 and combustible coal dust. There are nine (9) galleries (sections) in the  
16 tripper gallery that serve all four Monroe Power Plant units, designated by  
17 letters A, B, C, D, E, F, G, H, and J. Floor beam inspections were conducted  
18 to determine the condition of the gallery and prioritize sections based on the  
19 results. The inspection included the gallery conveyor floor system, floor  
20 plates, and floor supporting structural steel. Gallery C was identified as the  
21 next priority area in the inspection. Support beams and girders show signs  
22 of degradation and need to be replaced. This project will restore the  
23 structural integrity of the floor, the floor beams, girders, and associated  
24 connection hardware for this gallery section.

Line  
No.

- 1           • The capping of section 1A at Sibley Quarry continued for \$9.1 million  
2           (Exhibit A-12, Schedule B5.1, page 4, line 48). This portion of the site,  
3           twenty-seven (27) acres, reached its licensed capacity and requires capping  
4           per its landfill operating permit.

5

6   **Q65. What were the routine projects with capital expenditures greater than \$1**  
7   **million in 2024 for Steam Power Generation?**

8   A65. Routine projects with capital expenditures greater than \$1 million in 2024 are  
9   detailed on page 5 of Exhibit A-12, Schedule B5.1 and discussed below.

- 10           • In preparation for the 2025 periodic outage on Belle River Unit 1, \$1.9  
11           million was spent to start material procurement for the Belle River Unit 1  
12           east boiler feed pump turbine blades and rotor (Exhibit A-12, Schedule B5.1,  
13           page 5, line 63). During the 2022 Belle River Unit 1 periodic outage, the  
14           east boiler feed pump turbine rotor was inspected, and heavy rubbing was  
15           found on multiple stages where the blades connect to the rotor steeples.  
16           Crack indications were found and removed as a temporary repair, enabling  
17           the equipment to return to service with a plan for replacement during the  
18           2025 periodic outage. Engineering and material procurement was initiated  
19           to replace fifty-nine (59) medium voltage breakers (Exhibit A-12, Schedule  
20           B5.1, page 5, line 64) for \$1.3 million and ninety-three (93) 480-volt  
21           breakers (Exhibit A-12, Schedule B5.1, page 5, line 65) for \$1.2 million.  
22           The breakers are original to the 1980's era unit and the reliable operation of  
23           these breakers is at risk due to their age. These breakers are obsolete and no  
24           longer supported by the OEM. Additionally, these breakers are an electrical  
25           safety concern due to the obsolete trip device technology.

Line  
No.

- 1 • Belle River Unit 1 white coal mill overhaul was completed for \$1.0 million
- 2 (Exhibit A-12, Schedule B5.1, page 5, line 66). The coal mill overhaul was
- 3 due based on service hours, air flow performance, and lube oil analysis
- 4 indications of deteriorating internal components. Due to the abrasiveness of
- 5 coal, coal mill parts experience significant wear in the process of converting
- 6 lump coal to a fine powder consistency suitable for boiler combustion and
- 7 need to be disassembled, repaired, and components replaced approximately
- 8 every 10 years.
- 9 • The Belle River Unit 2 LP turbine rotors and blades were replaced for \$4.3
- 10 million (Exhibit A-12, Schedule B5.1, page 5, line 67). Inspections had
- 11 identified blade erosion and rotor cracking that needed to be addressed to
- 12 ensure continued safe and reliable operation of the LP turbines. This work
- 13 was a permanent fix to the issues identified and repaired on a temporary basis
- 14 in 2020.
- 15 • Waterwall tubes were replaced on Belle River Unit 2 for \$2.9 million
- 16 (Exhibit A-12, Schedule B5.1, page 5, line 68) to support continued reliable
- 17 boiler operation. The project replaced 2,300 square feet of boiler waterwall
- 18 panels damaged by quench cracking and soot blower erosion.
- 19 • Belle River Unit 2 IP turbine valves were overhauled for \$2.6 million
- 20 (Exhibit A-12, Schedule B5.1, page 5, line 69). This project overhauled the
- 21 four (4) IP turbine stop valves and four (4) control valves. The previous
- 22 valves were worn and required overhaul to operate properly. These valves
- 23 provide overspeed protection for the turbine and prevent possible
- 24 catastrophic failure.

Line  
No.

- 1           • \$1.9 million was spent to replace the Belle River Unit 2 exciter with a static  
2           exciter (Exhibit A-12, Schedule B5.1, page 5, line 70). Vibration levels  
3           indicated structural and mechanical integrity issues with the prior rotor  
4           components. Replacement of the exciter maintains future equipment  
5           reliability.
- 6           • The Belle River Unit 2 turbine stop valve actuators were replaced for \$1.8  
7           million (Exhibit A-12, Schedule B5.1, page 5, line 71). The original  
8           actuators provided by the OEM have been replaced across the industry due  
9           to maintenance issues, lack of spare parts, and an absence of qualified  
10          companies capable of repairing them. The replacements were required to  
11          maintain continued reliable operation of this system that controls turbine  
12          loading. Failure of these valves to properly operate would impact the ability  
13          to properly control unit output. These valves also provide overspeed  
14          protection for the turbine and prevent possible catastrophic failure.
- 15          • In preparation for the 2026 periodic outage on Belle River Unit 2,  
16          engineering and material procurement was initiated to replace fifty-eight  
17          (58) medium voltage breakers (Exhibit A-12, Schedule B5.1, page 5, line  
18          72) and ninety-four (94) 480-volt breakers (Exhibit A-12, Schedule B5.1,  
19          page 5, line 73) for \$1.2 million each. The breakers are original to the 1980's  
20          era unit. The reliable operation of these breakers is at risk due to their age.  
21          These breakers are obsolete and no longer supported by the OEM.  
22          Additionally, these breakers are an electrical safety concern due to the  
23          obsolete trip device technology.
- 24          • Over 400 primary superheater tube bends were replaced on Belle River Unit  
25          2 for \$1.1 million (Exhibit A-12, Schedule B5.1, page 5, line 74). The

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- 1 previous tubes were compromised from soot blower erosion and required  
2 replacement to support continued reliable boiler operations.
- 3 • In preparation for the 2025 periodic outage on Greenwood Unit 1, \$11.3  
4 million was spent on engineering and material procurement for the  
5 Greenwood Unit 1 LP turbine rotors and blades (Exhibit A-12, Schedule  
6 B5.1, page 5, line 75). Stress corrosion cracking of multiple blade root  
7 connections is being addressed to support continued safe and reliable  
8 operation of the LP turbines. Additionally, materials were procured for the  
9 replacement of the Greenwood Unit 1 feedwater heater No. 6 (Exhibit A-12,  
10 Schedule B5.1, page 5, line 76) and feedwater heater No. 3 (Exhibit A-12,  
11 Schedule B5.1, page 5, line 78) for \$2.1 million and \$1.8 million,  
12 respectively. A leak in the shell of feedwater heater No. 6 was discovered  
13 in March 2023. Phased Array Ultrasonic Testing (PAUT) also identified an  
14 8” long crack in the shell, several smaller connected indications on the inside  
15 diameter of the shell, and multiple internal weld cracks located between the  
16 desuperheating zone and the drain cooling zone of the feedwater heater.  
17 Feedwater heater No. 6 needs to be replaced to restore reliable service. The  
18 existing feedwater heater No. 3 is experiencing an increasing number of tube  
19 leaks and requires replacement to restore reliability. Both feedwater heaters  
20 take waste heat from the LP turbines and use it to preheat boiler feedwater,  
21 improving the overall efficiency of the steam power cycle. Also, over 2,100  
22 square feet of waterwall panels were procured for \$2.0 million (Exhibit A-  
23 12, Schedule B5.1, page 5, line 77). Waterwall tubes absorb heat from the  
24 combustion process to convert boiler water to steam, the basic process of the  
25 steam power cycle. A tube leak in any portion of the waterwall requires the

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- 1 unit to be removed from service for repair. The boiler tubes to be replaced  
2 are deteriorating due to corrosion fatigue combined with fireside corrosion,  
3 and tube thinning. Finally, \$1.3 million was spent on materials to overhaul  
4 the Greenwood Unit 1 turbine valves (Exhibit A-12, Schedule B5.1, page 5,  
5 line 79), including the reheat combination, equalizing, and ventilator valves.  
6 The valves are worn and required overhaul to support proper operation.  
7 These valves provide overspeed protection for the turbine and prevent  
8 possible catastrophic failure.
- 9 • For the Monroe Unit 1 IP turbine rotor (Exhibit A-12, Schedule B5.1, page  
10 5, line 80), the Company continued progress payments of \$1.1 million to  
11 replace the rotor in 2025. During an offsite inspection in 2023, creep void  
12 indications of cracking were found in the bore and the stage 1 wheel dovetail  
13 roots. The OEM performed the repairs required to return the unit to service  
14 on a short-term basis but also provided further analysis of the rotor that  
15 confirmed the rotor only had 30 months of useful service life remaining.
  - 16 • In preparation for the Monroe Unit 2 periodic outage in 2026, \$4.5 million  
17 was spent to start procurement of material to forge new LP turbine rotors  
18 and blades (Exhibit A-12, Schedule B5.1, page 5, line 81). Replacement is  
19 needed due to the industry-wide problem of stress corrosion cracking on the  
20 current LP turbine forgings. Additionally, \$1.9 million was spent to start  
21 material procurement for the SCR catalyst modules being replaced on layers  
22 1, 2, and 4 (Exhibit A-12, Schedule B5.1, page 5, line 85). The catalyst  
23 module replacements are required to maintain compliance with air permit  
24 emission limits for NOx and ammonia slip guidelines.



Line  
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- 1                   • The Monroe Unit 2 north and south air heater hot (Exhibit A-12, Schedule  
2                   B5.1, page 5, line 82) and cold (Exhibit A-12, Schedule B5.1, page 5, line  
3                   83) end baskets were replaced for \$3.6 million and \$2.9 million,  
4                   respectively. The air heater plays a critical heat transfer role to boiler  
5                   efficiency and flue gas equipment operational performance. The Monroe  
6                   air heaters capture heat in the combustion gases leaving the boiler  
7                   economizers at approximately 600F and utilize that heat to start the process  
8                   of warming the boiler feedwater. The air heaters are approximately 55 feet  
9                   in diameter and have air flow depth of 10 feet and weigh over 1,000 tons.  
10                  Due to the temperature cycling of the air heater baskets of 400F during each  
11                  revolution of the air heater (80 times per hour), the baskets experience both  
12                  corrosion and erosion from the fly ash contained in the flue gas which  
13                  causes deterioration and material loss. The Monroe cold end baskets  
14                  typically last 7-10 years. The previous cold-end baskets on Monroe Unit 2  
15                  north and south air heaters were in service since 2014 and were in failure  
16                  mode due to a significant loss (30 percent) of element material. The hot-  
17                  end baskets typically last 20 years. The previous hot-end baskets on Monroe  
18                  Unit 2 north and south air heaters were in service since 2004 and were in  
19                  failure mode due to a significant loss of material. As this condition  
20                  progresses, so does the risk of an out of balance condition, placing high  
21                  stresses on all components of the air heater. The imbalance issue will lead  
22                  to drive train failures, resulting in unit forced outages.
- 23                  • Monroe Unit 2 coal mill 2-6 (Exhibit A-12, Schedule B5.1, page 5, line 84),  
24                  2-2 (Exhibit A-12, Schedule B5.1, page 5, line 86), and 2-5 (Exhibit A-12,  
25                  Schedule B5.1, page 5, line 89) overhauls were completed for \$2.3 million,

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- 1           \$1.5 million, and \$1.3 million, respectively. The coal mill overhauls were  
2           due based on service hours, air flow performance, and lube oil analysis  
3           indications of deteriorating internal components. Due to the abrasiveness  
4           of coal, coal mill parts experience significant wear in the process of  
5           converting lump coal to a fine powder consistency suitable for boiler  
6           combustion and need to be disassembled, repaired, and components  
7           replaced approximately every 10 years.
- 8           • Monroe Unit 2 coal mill feeder controls were replaced for \$1.4 million  
9           (Exhibit A-12, Schedule B5.1, page 5, line 87). The previous coal mill  
10          feeder controls for all seven (7) coal mills were original equipment (1970's).  
11          Reliability of this equipment had diminished, causing unit derates.  
12          Replacing the obsolete controls was needed to address the reliability issues.  
13          This controls project upgrade improves reliability, accuracy of measuring  
14          coal flow, and boiler efficiency.
- 15          • \$1.4 million was spent on Monroe Unit 2 to complete the replacement of  
16          layer 3 SCR catalyst modules (Exhibit A-12, Schedule B5.1, page 5, line  
17          88). The catalyst module replacements are required to maintain compliance  
18          with air permit emission limits for NOx and ammonia slip guidelines.
- 19          • \$11.5 million was spent to replace Monroe Unit 3 waterwall tubes (Exhibit  
20          A-12, Schedule B5.1, page 5, line 90). Waterwall tubes absorb heat from  
21          the combustion process to convert boiler water to steam, the basic process  
22          of the steam power cycle. A tube leak in any portion of the waterwall  
23          requires the unit to be removed from service for repair. The boiler tubes  
24          replaced were deteriorating due to corrosion fatigue combined with fireside  
25          corrosion, and tube thinning.

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- 1           • \$4.0 million was spent to overhaul the Monroe Unit 3 turbine valves  
2           (Exhibit A-12, Schedule B5.1, page 5, line 91). Project scope included the  
3           four (4) throttle valves, four (4) intercept valves, eight (8) governor valves,  
4           and two (2) reheat stop valves. The previous valves were worn and required  
5           overhaul to continue proper operation until unit retirement. These valves  
6           provide overspeed protection for the turbine and prevent possible  
7           catastrophic failure.
- 8           • \$3.8 million was spent to complete the replacement of the existing Monroe  
9           Unit 3 coal mill primary air (PA) ductwork (Exhibit A-12, Schedule B5.1,  
10          page 5, line 92). The previous ductwork was thinning, resulting in fugitive  
11          dust leaks which pose a safety concern and required replacement. This  
12          project scope included removal and replacement of the interconnecting  
13          ductwork, slide gates, dampers, and expansion joints on the unit's seven  
14          coal mills.
- 15          • \$3.3 million was spent to complete the replacement of 1<sup>st</sup> row of turbine  
16          blades on the Monroe Unit 3 IP turbine to correct erosion on the previous  
17          blades (Exhibit A-12, Schedule B5.1, page 5, line 93).
- 18          • Twelve (12) Monroe Unit 3 expansion joints were replaced for \$2.5 million  
19          due to leakage or being at risk of near-term leaking (Exhibit A-12, Schedule  
20          B5.1, page 5, line 94). This project covered multiple areas in the air  
21          duct/flue gas systems that allows thermal expansion of the process  
22          ductwork. Scope of work included vacuuming of all areas to provide a safe  
23          workspace, confined space rescue services, scaffold for safe access,  
24          lead/asbestos abatement, and replacement of the expansion joints. The

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1 replacements were based on unit reliability, efficiency, and safety risk to  
2 plant personnel.

3 • Monroe Unit 3 horizontal reheater tubes (4,000 linear feet) were replaced  
4 for \$2.3 million (Exhibit A-12, Schedule B5.1, page 5, line 95). The  
5 horizontal reheater is located within the downdraft section of the boiler.  
6 These tubes required replacement to avoid tube failure outages. Tube  
7 failures occur from oxygen pitting corrosion, fly ash erosion, abrasive wear  
8 of closely spaced horizontal reheater and primary superheater tubes, and the  
9 use of sootblowers which operate to remove/prevent ash build-up.

10 • \$2.3 million was spent to complete the replacement of the Monroe Unit 3  
11 north & south air heater cold end baskets (Exhibit A-12, Schedule B5.1,  
12 page 5, line 96). The previous baskets were in failure mode with significant  
13 loss (30 percent) of element material. The previous baskets had been in  
14 service since 2015 and had a 7–10-year life. The integrity, reliability, and  
15 efficiency of the Monroe Unit 3 north & south air heater cold-end baskets  
16 have been restored.

17 • Monroe Unit 3 reheat outlet pendants were replaced for \$2.3 million  
18 (Exhibit A-12, Schedule B5.1, page 5, line 97). The boiler reheater tubes  
19 are critical to steam turbine design and operations. Reheater tubes allow  
20 exhaust steam from the turbine to be reheated in the boiler and reintroduced  
21 into the IP and LP turbines with additional energy that adds to unit MW  
22 output at improved efficiency levels. The replacements were based on near-  
23 term tube failure risk which would force the unit offline for repair.

24 • Replacement of the SCR catalyst modules for layers 2, 3, and 4 on Monroe  
25 Unit 3 was completed for \$2.2 million (Exhibit A-12, Schedule B5.1, page

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- 1 5, line 98). The catalyst module replacements were required to maintain  
2 compliance with air permit emission limits for NOx and ammonia slip  
3 guidelines.
- 4 • \$1.4 million was spent to replace the upper and lower bearings on Monroe  
5 Unit 3 coal mill classifiers (Exhibit A-12, Schedule B5.1, page 5, line 99).  
6 The rebuild cycle for the classifiers is based on bearing life expectancy,  
7 OEM recommendations, and condition of the internal wear components.  
8 The classifier bearings are recommended for replacement every 10 years,  
9 and the previous Monroe Unit 3 bearings had been in service since 2015.
  - 10 • Monroe Unit 3 coal mill 3-7 silo was rebuilt for \$1.2 million (Exhibit A-12,  
11 Schedule B5.1, page 5, line 100). The chemical and abrasive properties of  
12 coal within the silos resulted in corrosion and erosion of the silo walls  
13 creating coal leaks and compromised the structural integrity. Repairs were  
14 required for a safe workspace and continued reliable operation.
  - 15 • In preparation for the Monroe Unit 4 2025 periodic outage, \$8.7 million was  
16 spent to continue procurement of long lead materials related to  
17 refurbishment of the LP turbines (Exhibit A-12, Schedule B5.1, page 5, line  
18 101). Refurbishment is needed due to the industry-wide problem of stress  
19 corrosion cracking on the current LP turbine which could result in  
20 unexpected catastrophic failure. The LP rotors that were installed on  
21 Monroe Unit 1 in 2001 have been replaced with new upgraded rotors in  
22 2023. Due to the cost of forging new rotors or the extended outage required  
23 to perform the refurbishment of the Monroe Unit 4 rotors, Unit 4's rotors  
24 will be replaced with those that were removed from Unit 1. The Unit 1  
25 rotors will be refurbished to provide safe and reliable operation of the Unit

Line  
No.

- 1 4 LP turbines until the projected retirement of Unit 4 in 2028. In addition,  
2 SCR catalyst modules for layers 1, 3, and 4 were purchased for \$1.9 million  
3 (Exhibit A-12, Schedule B5.1, page 5, line 102). The catalyst module  
4 replacements are required to maintain compliance with air permit emission  
5 limits for NOx and ammonia slip guidelines. \$1.4 million was spent to  
6 procure materials for Monroe Unit 4 expansion joints to be replaced in 2025  
7 (Exhibit A-12, Schedule B5.1, page 5, line 103). Fourteen (14) high priority  
8 Monroe Unit 4 expansion joints were identified to be replaced due to  
9 leakage. A leak can affect unit reliability and efficiency, and result in a  
10 safety risk to plant personnel.
- 11 • \$2.0 million was spent on replacing underground piping between storm  
12 station #1 and the equalization basin (Exhibit A-12, Schedule B5.1, page 5,  
13 line 104). The 36" diameter 1970s vintage reinforced fiberglass  
14 underground pipeline that transports water from storm station #1 to the  
15 equalization basin ruptured midway sending storm water to the surface.  
16 Further internal inspection revealed several more areas where the piping  
17 was exhibiting cracking and deformation where additional failures may  
18 occur. Approximately 600 linear feet of pipe was replaced to restore the  
19 damaged piping.
  - 20 • The diesel fire pump in screenhouse #1 was replaced for \$1.2 million  
21 (Exhibit A-12, Schedule B5.1, page 5, line 105). This project was initiated  
22 because the current diesel-powered pump from the plant's original  
23 construction was determined to have critical failures and could not be  
24 repaired.

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- 1 • Monroe underground storage tank No. 389 (Exhibit A-12, Schedule B5.1,  
2 page 5, line 106) was replaced with an above ground storage tank for \$1.1  
3 million. The previous tank had been in service since 1993. The tank  
4 collects used oil and is constructed of double-walled steel. Tank No. 389 is  
5 about the size of a school bus and has a capacity of 5,750 gallons. This  
6 project mitigates the oil spill risk and supports continued environmental  
7 compliance.
- 8 • The Monroe fuel supply coal pile runoff oil wastewater system replacement  
9 project was completed for \$5.5 million (Exhibit A-12, Schedule B5.1, page  
10 5, line 107). As previously discussed above in the 2023 steam routine  
11 projects section, this project enhances environmental compliance by  
12 reducing the risk of oil contaminants from the storm water and coal pile run-  
13 off systems reaching Lake Erie.
- 14 • Monroe fuel supply tripper car gallery C floor replacement (10,750 square  
15 feet of elevated structure) was completed for \$4.1 million (Exhibit A-12,  
16 Schedule B5.1, page 5, line 108). The original tripper gallery floor,  
17 supporting floor beams, and floor beam top flanges had corroded over time  
18 and required replacement to ensure worker safety during washdown  
19 activities required to control fugitive and combustible coal dust. There are  
20 9 galleries (sections) in the tripper gallery that serve all four Monroe Power  
21 Plant units, designated by letters A, B, C, D, E, F, G, H, and J. Floor beam  
22 inspections were conducted to determine the condition of the gallery and  
23 prioritize sections based on the results. The inspection included the gallery  
24 conveyor floor system, floor plates, and floor supporting structural steel.  
25 Gallery C was identified as the next priority area in the inspection. Support

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1 beams and girders showed signs of degradation and needed to be replaced.

2 This project restored the structural integrity of the floor, the floor beams,

3 girders, and associated connection hardware for this gallery section.

4 • \$3.3 million was spent in Monroe fuel supply to replace the transfer chutes

5 in the CV-C2 Loading Zone (Exhibit A-12, Schedule B5.1, page 5, line

6 109). This project replaced three (3) transfer chutes (C1A to CV-C2, C1B

7 to CV-C2 & C1C to CV-C2) that load onto CV-C2 so that the transfer point

8 is reconfigured such that the coal stream is less susceptible to coal dust

9 generation, pluggage, and spillage.

10 • The Monroe fuel supply CV07 conveyor belt was replaced for \$1.2 million

11 (Exhibit A-12, Schedule B5.1, page 5, line 110). The conveyor belt moves

12 the coal from the coal pile to the powerhouse. The belt developed a tear

13 and required replacement.

14 • The capping of section 1A at Sibley Quarry was completed for \$8.2 million

15 (Exhibit A-12, Schedule B5.1, page 5, line 111). This portion of the site,

16 twenty-seven (27) acres, reached its licensed capacity and required capping

17 as it is no longer available for material disposal.

18

19 **Q66. What are the routine projects with projected capital expenditures greater than**

20 **\$1 million to be executed in 2025 for Steam Power Generation?**

21 A66. Planned maintenance projects greater than \$1 million in 2025 are detailed on page

22 6 of Exhibit A-12, Schedule B5.1 and discussed below.

23 • \$5.9 million will be spent on Belle River Unit 1 to complete replacement of

24 waterwall tubes (Exhibit A-12, Schedule B5.1, page 6, line 125). The project

25 will replace 2,300 square feet of boiler waterwall panels damaged by quench



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1 cracking and sootblower erosion to support continued reliable boiler  
2 operation.

3 • \$4.9 million will be spent to replace baskets on Belle River Unit 1 secondary  
4 air heater (Exhibit A-12, Schedule B5.1, page 6, line 126). The secondary  
5 air heaters are approximately 37 feet in diameter and have air flow depth of  
6 5 feet. The baskets of the secondary air heaters have been in service for  
7 over 10 years, have eroded, are loose and at risk of falling out, causing a  
8 forced outage. The integrity, reliability, and efficiency of the secondary air  
9 heater baskets will be restored with this project.

10 • Belle River Unit 1 IP turbine valves (Exhibit A-12, Schedule B5.1, page 6,  
11 line 127) will be overhauled for \$4.0 million. The four (4) IP turbine control  
12 and four (4) stop valves begin to wear within 6 to 8 years of an overhaul and  
13 must be disassembled, inspected, and repaired every other periodic  
14 outage. The IP turbine control and stop valves need to operate properly to  
15 provide overspeed protection for the turbine and prevent possible  
16 catastrophic failure.

17 • 1,400 linear feet of Belle River Unit 1 horizontal middle reheat tubes  
18 (Exhibit A-12, Schedule B5.1, page 6, line 128) will be replaced for \$3.0  
19 million. Corrosion and sootblower erosion have degraded the original  
20 1980's era factory tube welds in the horizontal middle reheater.

21 • \$2.7 million will be spent to replace the Belle River Unit 1 duplex heater  
22 (No. 1 and No. 2 low-pressure feedwater heater) (Exhibit A-12, Schedule  
23 B5.1, page 6, line 129). The low-pressure heaters are original plant  
24 equipment. Eddy current testing and borescope inspections of these heaters

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- 1 identified tube wall loss damage at the support plates. Replacement of the  
2 duplex heater is required to maintain unit performance.
- 3 • Ninety-three (93) 480-volt breakers on Belle River Unit 1 (Exhibit A-12,  
4 Schedule B5.1, page 6, line 130) will be replaced for \$2.7 million. The  
5 current breakers are original to the 1980's era unit and the reliable operation  
6 of these breakers is at risk due to their age. These breakers are obsolete and  
7 no longer supported by the OEM. Additionally, these breakers are an  
8 electrical safety concern due to the obsolete trip device technology.
  - 9 • \$1.8 million will be spent to complete the replacement of the Belle River  
10 Unit 1 east boiler feed pump turbine blades and rotor (Exhibit A-12,  
11 Schedule B5.1, page 6, line 131). Crack indications were found in 2022  
12 which necessitated removing one stage of blade rows and machining one  
13 stage of blade rows as temporary repairs to enable the equipment to return  
14 to service with a plan for replacement during the 2025 periodic outage.
  - 15 • The Belle River Unit 1 east and west boiler feed pump turbine control  
16 actuators will be replaced for \$1.5 million (Exhibit A-12, Schedule B5.1,  
17 page 6, line 132). The original actuators provided by the OEM have been  
18 replaced across the industry due to maintenance issues, lack of spare parts,  
19 and an absence of qualified companies capable of repairing them. The  
20 replacements are required to maintain continued reliable operation of this  
21 system that controls the feed pump.
  - 22 • Ninety-four (94) 480-volt breakers on Belle River Unit 2 (Exhibit A-12,  
23 Schedule B5.1, page 6, line 133) will be replaced for \$1.6 million. The  
24 current breakers are original to the 1980s-era unit and the reliable operation  
25 of these breakers is at risk due to their age. These breakers are obsolete and

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- 1 no longer supported by the OEM. Additionally, these breakers are an  
2 electrical safety concern due to the obsolete trip device technology.
- 3 • In preparation for the 2026 Belle River Unit 2 periodic outage, \$1.3 million  
4 will be spent to start material procurement for a generator machine breaker  
5 (Exhibit A-12, Schedule B5.1, page 6, line 134). This breaker is original to  
6 the plant constructed in 1981 and is now obsolete, not supported by the  
7 OEM, and has reliability concerns. Failure of this breaker results in full unit  
8 outages and electrical safety hazards.
  - 9 • Engineering and material procurement will continue for the replacement of  
10 the Belle River north auxiliary boiler (Exhibit A-12, Schedule B5.1, page 6,  
11 line 135) and Belle River south auxiliary boiler (Exhibit A-12, Schedule  
12 B5.1, page 6, line 136) for \$1.8 and \$1.7 million, respectively. Both  
13 auxiliary boilers are original to the 1980s-era plant. They have become  
14 unreliable due to frequent tube leaks, resulting in multiple tubes being  
15 plugged which significantly reduces boiler efficiency. As boiler efficiency  
16 is reduced, there is an increasing risk that the boilers will not provide  
17 sufficient steam for unit startups or building heat. Without sufficient  
18 building heat, there will be freezing damage to various plant systems and  
19 equipment and safety issues for plant personnel.
  - 20 • Installation of ninety-four (94) common system 480-volt breakers (Exhibit  
21 A-12, Schedule B5.1, page 6, line 137) will begin at Belle River Power Plant  
22 for \$1.7 million. The current breakers are original to the 1980s-era unit and  
23 the reliable operation of these breakers is at risk due to their age. These  
24 breakers are obsolete and no longer supported by the OEM. Additionally,

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- 1                   these breakers are an electrical safety concern due to the obsolete trip device
- 2                   technology.
- 3                   • \$9.4 million will be spent to complete the Greenwood Unit 1 LP turbine
- 4                   rotors and blades replacement project (Exhibit A-12, Schedule B5.1, page 6,
- 5                   line 138). Stress corrosion cracking of multiple blade root connections is
- 6                   being addressed to ensure continued safe and reliable operation of the LP
- 7                   turbines.
- 8                   • 2,200 square feet of waterwall will be replaced on Greenwood Unit 1 for
- 9                   \$5.3 million (Exhibit A-12, Schedule B5.1, page 6, line 139). Waterwall
- 10                  tubes absorb heat from the combustion process to convert boiler water to
- 11                  steam, the basic process of the steam power cycle. A tube leak in any portion
- 12                  of the waterwall requires the unit to be removed from service for repair. The
- 13                  boiler tubes to be replaced are deteriorating due to corrosion fatigue.
- 14                  • The Greenwood Unit 1 north boiler feed pump turbine last row of blades will
- 15                  be replaced for \$1.6 million to correct erosion damage on the existing blades
- 16                  (Exhibit A-12, Schedule B5.1, page 6, line 140).
- 17                  • The Greenwood Unit 1 turbine valves will be rebuilt for \$1.5 million
- 18                  (Exhibit A-12, Schedule B5.1, page 6, line 141). The valves are worn and
- 19                  require overhaul to operate safely and properly. These valves provide
- 20                  overspeed protection for the turbine and prevent possible catastrophic
- 21                  failure.
- 22                  • Greenwood Unit 1 feedwater heater No. 3 (Exhibit A-12, Schedule B5.1,
- 23                  page 6, line 142) and feedwater heater No. 6 (Exhibit A-12, Schedule B5.1,
- 24                  page 6, line 143) will be replaced for \$1.5 million and \$1.4 million,
- 25                  respectively. The existing feedwater heater No. 3 is experiencing an

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- 1 increasing number of tube leaks and requires replacement to restore  
2 reliability. A leak in the shell of feedwater heater No. 6 was discovered in  
3 March 2023. Phased Array Ultrasonic Testing (PAUT) identified an 8" long  
4 crack in the shell, several smaller connected indications on the inside  
5 diameter of the shell, and multiple internal weld cracks located between the  
6 desuperheating zone and the drain cooling zone of the feedwater heater. The  
7 feedwater heater needs to be replaced to restore reliable service. Both  
8 feedwater heaters take waste heat from the LP turbines and use it to preheat  
9 boiler feedwater improving the overall efficiency of the steam power cycle.  
10 All steam turbine power cycles utilize feedwater heating in this manner.
- 11 • Monroe Unit 1 IP turbine rotor (Exhibit A-12, Schedule B5.1, page 6, line  
12 144) replacement will be completed for \$4.4 million. During offsite  
13 inspection in 2023, creep void indications of cracking were found in the bore  
14 and the stage 1 wheel dovetail roots. The OEM performed the work required  
15 to return the rotor to service on a short-term basis but also provided further  
16 analysis of the rotor that confirmed the need to replace the rotor soon,  
17 concluding that it could only be returned to service for no more than 30  
18 months.
  - 19 • Monroe Unit 1 SCR catalyst modules for layer 3 will be replaced for \$3.3  
20 million (Exhibit A-12, Schedule B5.1, page 6, line 145). The catalyst  
21 module replacements are required to maintain compliance with air permit  
22 emission limits for NOx and ammonia slip guidelines.
  - 23 • Monroe Unit 1 coal mill feeder controls will be replaced for \$1.2 million  
24 (Exhibit A-12, Schedule B5.1, page 6, line 146). The current coal mill feeder  
25 controls for all seven (7) coal mills are original equipment (1970s).

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- 1 Reliability of this equipment has diminished, causing unit derates.
- 2 Replacing the obsolete controls is needed to address the reliability issues.
- 3 This controls project upgrade will improve reliability, accuracy of measuring
- 4 coal flow, and boiler efficiency.
- 5 • In preparation for the Monroe Unit 2 periodic outage in 2026, \$14.8 million
- 6 will be spent to continue procurement payments on material to forge new LP
- 7 turbine rotors and blades (Exhibit A-12, Schedule B5.1, page 6, line 147).
- 8 Replacement is needed due to the industry-wide problem of stress corrosion
- 9 cracking on the current LP turbine forgings. In addition, Monroe Unit 2 SCR
- 10 catalyst modules for layers 1, 2, and 4 will be purchased for \$2.6 million
- 11 (Exhibit A-12, Schedule B5.1, page 6, line 148). The catalyst module
- 12 replacements are required to maintain compliance with air permit emission
- 13 limits for NOx and ammonia slip guidelines. Lastly, \$2.0 million will be
- 14 spent on precipitator switched integrated rectifiers (SIR) material (Exhibit
- 15 A-12, Schedule B5.1, page 6, line 149). The current SIRs are becoming
- 16 obsolete and will be unsupported by the OEM after 2027. SIR failures result
- 17 in particulate matter passing beyond the precipitator where it would
- 18 normally be captured. Once past the precipitator, the particulate matter
- 19 erodes ID fan blades and degrades the performance of the FGD.
- 20 • \$10.4 million will be spent to continue the replacement of the Monroe Unit
- 21 4 LPA and LPB turbine rotors and blades (Exhibit A-12, Schedule B5.1,
- 22 page 6, line 150). Refurbishment is needed due to the industry-wide problem
- 23 of stress corrosion cracking on the current LP turbine which could result in
- 24 unexpected catastrophic failure. The LP rotors that were installed on
- 25 Monroe Unit 1 in 2001 have been replaced with new upgraded rotors in

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- 1 2023. Due to the cost of forging new rotors or the extended outage required  
2 to perform the refurbishment of the Monroe Unit 4 rotors, Unit 4's rotors  
3 will be replaced with those that were removed from Unit 1. The Unit 1 rotors  
4 are being refurbished to provide safe and reliable operation of the Unit 4 LP  
5 turbines until the projected retirement of Unit 4 in 2028.
- 6 • \$4.5 million will be spent to overhaul the Monroe Unit 4 turbine valves  
7 (Exhibit A-12, Schedule B5.1, page 6, line 151). Project scope includes the  
8 four (4) stop valves, four (4) control valves, two (2) combined reheat stop  
9 valves, two (2) intercept valves, an equalizer valve, and a ventilator valve.  
10 The valves are worn and require overhaul for proper operation until unit  
11 retirement.
- 12 • \$3.7 million will be spent to complete the Monroe Unit 4 coal mill primary  
13 air duct and dampers project (Exhibit A-12, Schedule B5.1, page 6, line 152).  
14 The existing ductwork is thinning, resulting in fugitive coal dust leaks which  
15 pose a safety concern, and requires replacement.
- 16 • \$2.8 million will be spent to complete replacement of Monroe Unit 4  
17 expansion joints (Exhibit A-12, Schedule B5.1, page 6, line 153). Fourteen  
18 (14) high priority Monroe Power Plant Unit 4 expansion joints have been  
19 identified to be replaced due to leakage. A leak can affect unit reliability,  
20 efficiency, and result in a safety risk to plant personnel.
- 21 • Reheat outlet pendants will be replaced on Monroe Unit 4 for \$2.6 million  
22 (Exhibit A-12, Schedule B5.1, page 6, line 154). The boiler reheater tubes  
23 are critical to steam turbine design and operations. Reheater tubes allow  
24 exhaust steam from the HP turbine to be reheated in the boiler and  
25 reintroduced into the IP and LP turbines with additional energy that adds to

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- 1 unit MW output at improved efficiency levels. The replacements were based
- 2 on near term tube failure risk which would force the unit offline for repair.
- 3 • \$2.2 million will be spent to replace the Unit 4 FGD inlet expansion joint
- 4 and flanges on both upstream and downstream sides of the joint (Exhibit A-
- 5 12, Schedule B5.1, page 6, line 155). The inlet expansion joint is essential
- 6 to reliability for inlet flue gas to enter the absorber tower. It allows for
- 7 expansion and contraction of the inlet duct with changing temperatures
- 8 (during a shutdown/startup of the unit). The existing joint and flange surface
- 9 is worn from normal operation and needs replacement to allow the joint to
- 10 seal.
- 11 • Monroe Unit 4 SCR catalyst modules for layers 1, 3, and 4 will be replaced
- 12 for \$2.1 million (Exhibit A-12, Schedule B5.1, page 6, line 156). The
- 13 catalyst module replacements are required to maintain compliance with air
- 14 permit emission limits for NOx and ammonia slip guidelines.
- 15 • \$1.4 million will be spent to complete the Monroe Unit 4 DCS and control
- 16 room modifications (Exhibit A-12, Schedule B5.1, page 6, line 157). The
- 17 equipment and software are at risk from a reliability perspective, requiring
- 18 modifications to keep the plant's control systems reliable. The DCS
- 19 hardware was last replaced over a decade ago and the associated software
- 20 dates to the 1980s. Additionally, the equipment is no longer supported by
- 21 the vendor. The Company has scaled back this project to focus on the critical
- 22 work necessary to support continued operations until the projected
- 23 retirement of Unit 4 in 2028.
- 24 • The Monroe Unit 4 secondary heat exchanger (Exhibit A-12, Schedule B5.1,
- 25 page 6, line 158) will be replaced for \$1.2 million. The Unit 4 secondary



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1 heat exchanger is an original piece of equipment (1970s-era) and provides  
2 process heat to the combustion coils that are needed for unit start-up and  
3 building heating which will continue to be needed after unit retirement. The  
4 existing secondary heat exchanger has become unreliable due to an  
5 increasing number of tube leaks. Replacement of the secondary heat  
6 exchanger will improve unit reliability and maintain building heating  
7 requirements.

- 8 • The Sibley Quarry chimney drain will be lifted for \$4.0 million (Exhibit A-  
9 12, Schedule B5.1, page 6, line 159). The continued disposal of ash from  
10 the Monroe bottom ash basin project and other fill material has raised the  
11 floor level of Sibley Quarry and the existing chimney drain needs to be raised  
12 to maintain safe operations. This lift will incorporate changes to the  
13 structural, electrical, and mechanical modifications to the existing chimney  
14 drain to allow it to continue to control the level of groundwater beneath the  
15 landfill while meeting or exceeding the isolation distance requirements to  
16 adjacent disposed waste. Scope includes placement of 5,900 cubic yards of  
17 drainage layer stone and a 40-foot vertical lift of the site's chimney drain,  
18 including concrete, piping, and power supply cables.

19

20 **Q67. What are the routine projects with projected capital expenditures greater than**  
21 **\$1 million to be executed in 2026 for Steam Power Generation?**

22 A67. Planned maintenance projects greater than \$1 million in 2026 are detailed on page  
23 7 of Exhibit A-12, Schedule B5.1 and discussed below.

- 24 • 2,300 square feet of waterwall tubes will be replaced on Belle River Unit 2  
25 for \$5.7 million (Exhibit A-12, Schedule B5.1, page 7, line 172). The project

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- 1 will replace boiler waterwall panels damaged by quench cracking and soot  
2 blower erosion to support continued reliable boiler operation.
- 3 • The Belle River Unit 2 secondary air heater baskets will be replaced for \$4.9  
4 million (Exhibit A-12, Schedule B5.1, page 7, line 173). The baskets of the  
5 secondary air heaters have been in service since 2012, have eroded, are  
6 loose, and are at risk of falling out causing a forced outage. The integrity,  
7 reliability, and efficiency of the secondary air heater baskets will be restored  
8 with this project.
  - 9 • The Belle River Unit 2 high pressure turbine valves will be overhauled for  
10 \$3.6 million (Exhibit A-12, Schedule B5.1, page 7, line 174). Project scope  
11 includes the 4 stop valves and 4 control valves. The valves are worn and  
12 require overhaul for proper operation. These valves provide overspeed  
13 protection for the turbine and prevent possible catastrophic failure.
  - 14 • The Belle River Unit 2 generator machine breaker will be replaced for \$3.0  
15 million (Exhibit A-12, Schedule B5.1, page 7, line 175). This breaker is  
16 original to the plant constructed in 1981 and is now obsolete, not supported  
17 by the OEM, and has reliability concerns. Failure of this breaker results in  
18 full unit outages and electrical safety hazards.
  - 19 • 1,400 linear feet of horizontal middle reheat tubes will be replaced on Belle  
20 River Unit 2 for \$2.7 million (Exhibit A-12, Schedule B5.1, page 7, line  
21 176). Corrosion and sootblower erosion have degraded the original 1980s-  
22 era factory tube welds in the horizontal middle reheater.
  - 23 • Expansion joints on Belle River Unit 2 will be replaced for \$2.6 million  
24 (Exhibit A-12, Schedule B5.1, page 7, line 177). This project replaces ten  
25 (10) expansion joints on the air side of the ductwork going to the boiler and

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- 1 on the gas side of the ductwork from the boiler. A comprehensive plan to  
2 identify and replace expansion joints on the air and gas ducts was developed  
3 and is being implemented to address leakage. The replacements are based  
4 on near-term failure risk, which would affect unit reliability, efficiency, and  
5 result in a safety risk to plant personnel.
- 6 • Ninety-four (94) 480-Volt breakers on Belle River Unit 2 will be replaced  
7 for \$1.4 million (Exhibit A-12, Schedule B5.1, page 7, line 178). The current  
8 breakers are original to the 1980s-era unit and the reliable operation of these  
9 breakers is at risk due to their age. These breakers are obsolete and no longer  
10 supported by the OEM. Additionally, these breakers are an electrical safety  
11 concern due to the obsolete trip device technology.
  - 12 • Belle River Unit 2 east and west boiler feed pump turbine control actuators  
13 (Exhibit A-12, Schedule B5.1, page 7, line 179) will be replaced for \$1.2  
14 million. The original actuators provided by the OEM have been replaced  
15 across the industry due to maintenance issues, lack of spare parts, and an  
16 absence of qualified companies capable of repairing them. The replacements  
17 are required to maintain continued reliable operation of this system that  
18 controls the feed pump.
  - 19 • A transformer containment pad will be built on the Belle River site for \$4.2  
20 million (Exhibit A-12, Schedule B5.1, page 6, line 180). The pad will house  
21 the Blue Water Energy Center main unit transformers along with other  
22 transformers, as needed. This containment pad is being built at the Belle  
23 River site to be a centrally located storage site supporting the north area  
24 plants.

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- 1           • The Belle River Power Plant south auxiliary boiler (Exhibit A-12, Schedule  
2           B5.1, page 7, line 181) and north auxiliary boiler (Exhibit A-12, Schedule  
3           B5.1, page 7, line 182) will be replaced for \$3.2 and \$3.1 million,  
4           respectively. Both auxiliary boilers are original to the 1980s-era plant. They  
5           have become unreliable due to frequent tube leaks, resulting in multiple  
6           tubes being plugged which significantly reduces boiler efficiency. As boiler  
7           efficiency is reduced, there is an increasing risk that the boilers will not  
8           provide sufficient steam for unit startups or building heat. Without sufficient  
9           building heat, there will be freezing damage to various plant systems and  
10          equipment and safety issues for plant personnel.
- 11          • The fire suppression system will be replaced in the Belle River Power Plant  
12          relay rooms for \$1.0 million (Exhibit A-12, Schedule B5.1, page 7, line 183).  
13          Replacement parts for the current system are obsolete and can no longer be  
14          sourced. The new system will include modern components and continue to  
15          provide fire suppression to the Belle River Power Plant relay rooms and  
16          cable spreading rooms.
- 17          • In preparation for the 2027 periodic outage on Greenwood Unit 1,  
18          engineering and material procurement will begin for IP turbine blade rows  
19          for \$2.1 million (Exhibit A-12, Schedule B5.1, page 7, line 184). Inspections  
20          performed during the 2025 outage indicated rubbing and wear on the blades  
21          that needs to be corrected. Additionally, \$1.4 million will be spent on  
22          material procurement to replace tubes in the main unit condenser air removal  
23          sections (Exhibit A-12, Schedule B5.1, page 7, line 186). These sections of  
24          the condenser average 14% plugged and are impacting the performance of  
25          the unit as well as increasing the risk of forced outages due to in-service

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- 1 leaks. Also, an ID fan motor will be procured for \$1.2 million (Exhibit A-  
2 12, Schedule B5.1, page 7, line 187). The existing motor is original to the  
3 plant from 1979 and is due for maintenance. Finally, \$1.0 million will be  
4 spent on procuring the finishing superheat pendants material (Exhibit A-12,  
5 Schedule B5.1, page 7, line 188). This project will replace thirty-six (36)  
6 superheat pendants. The superheat pendants are failing due to thermal  
7 fatigue, dissimilar metal weld, and creep. This project will restore the  
8 reliability of the finishing superheat pendant section of the boiler.
- 9 • \$1.6 million will be spent to replace Greenwood Energy Center underground  
10 storage tank No. 377 (Exhibit A-12, Schedule B5.1, page 6, line 185). The  
11 tank has been in service for over 30 years. Underground storage tanks that  
12 have been in service for this many years have an increased risk of failure,  
13 potentially allowing the contents to leak, contaminating the soil and  
14 groundwater around the tank. Tank No. 377 contains gasoline fuel with a  
15 capacity of 2,500 gallons.
  - 16 • In preparation for the Monroe Unit 1 periodic outage in 2027, materials for  
17 SCR catalyst modules for layers 1, 2, and 4 will be procured for \$6.9 million  
18 (Exhibit A-12, Schedule B5.1, page 7, line 189). The catalyst module  
19 replacements are required to maintain compliance with air permit emission  
20 limits for NOx and ammonia slip guidelines. Additionally, \$2.4 million will  
21 be spent on materials for replacement of 16 expansion joints (Exhibit A-12,  
22 Schedule B5.1, page 7, line 190). Expansion joints are replaced due to  
23 leakage or being at risk of near-term leaking. This project covers multiple  
24 areas in the air duct/flue gas systems that provide a means of thermal  
25 expansion of the process ductwork. Scope of work includes vacuuming of

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- 1 all areas to provide a safe workspace, confined space rescue services,  
2 scaffold for safe access, lead/asbestos abatement, and replacement of the  
3 expansion joints. Also, materials for the waterwall replacement project will  
4 be procured for \$1.7 million (Exhibit A-12, Schedule B5.1, page 7, line 191).  
5 Waterwall tubes absorb heat from the combustion process to convert boiler  
6 water to steam, the basic process of the steam power cycle. A tube leak in  
7 any portion of the waterwall requires the unit to be removed from service for  
8 repair, otherwise additional damage will be incurred on the boiler which  
9 requires more extensive outage time to repair. The boiler tubes being  
10 replaced are deteriorating due to corrosion fatigue combined with fireside  
11 corrosion and tube thinning. Finally, coal mill classifier rebuild material will  
12 be procured for \$1.5 million (Exhibit A-12, Schedule B5.1, page 7, line 192).  
13 The rebuild cycle for the classifiers is based on bearing life expectancy,  
14 OEM recommendations, and condition of the internal wear components.  
15 The classifier bearings are recommended for replacement every 10 years,  
16 and the current Monroe Unit 1 bearings have been in service since 2017.
- 17 • Monroe Unit 2 waterwall replacement will be completed for \$18.1 million  
18 (Exhibit A-12, Schedule B5.1, page 7, line 193). The project replaces 2,000  
19 square feet of boiler waterwall tubes. The boiler tubes are deteriorating due  
20 to corrosion fatigue combined with fireside corrosion and tube thinning.
  - 21 • The Monroe Unit 2 LPA and LPB turbine rotors and blades will be replaced  
22 for \$10.0 million (Exhibit A-12, Schedule B5.1, page 7, line 194).  
23 Refurbishment is needed due to the industry-wide problem of stress  
24 corrosion cracking on the current LP turbine which could result in  
25 unexpected catastrophic failure.

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- 1           • The Monroe Unit 2 coal mill classifiers will be overhauled for \$4.5 million  
2           (Exhibit A-12, Schedule B5.1, page 7, line 195). The rebuild cycle for the  
3           classifiers is based on bearing life expectancy, OEM recommendations, and  
4           condition of the internal wear components. The Monroe Unit 2 classifiers  
5           have been in service since 2017.
- 6           • Sixteen (16) expansion joints for Monroe Unit 2 will be replaced for \$4.1  
7           million (Exhibit A-12, Schedule B5.1, page 7, line 196) due to leakage or  
8           being at risk of near-term leaking. This project covers multiple areas in the  
9           air duct/flue gas systems that provide a means of thermal expansion of the  
10          process ductwork. Scope of work includes vacuuming of all areas to provide  
11          a safe workspace, confined space rescue services, scaffold for safe access,  
12          lead/asbestos abatement, and replacement of the expansion joints. The  
13          replacements are based on near-term failure risk which would affect unit  
14          reliability, efficiency, and result in a safety risk to plant personnel.
- 15          • SCR catalyst modules on layers 1, 2, and 4 on Monroe Unit 2 will be  
16          replaced for \$3.9 million (Exhibit A-12, Schedule B5.1, page 7, line 197).  
17          The catalyst module replacements are required to maintain compliance with  
18          air permit emission limits for NOx and ammonia slip guidelines.
- 19          • Forty-eight (48) precipitator SIRs will be replaced for \$3.5 million (Exhibit  
20          A-12, Schedule B5.1, page 7, line 198). The current SIRs are becoming  
21          obsolete and will be unsupported by the OEM after 2027. SIR failures result  
22          in particulate matter passing beyond the precipitator where it would  
23          normally be captured. Once past the precipitator, the particulate matter  
24          erodes ID fan blades and degrades the performance of the FGD.

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- 1 • 1,230 linear feet of Monroe Unit 2 economizer tubes will be replaced for  
2 \$3.5 million (Exhibit A-12, Schedule B5.1, page 7, line 199). The boiler  
3 economizers are a critical component of the boiler tubing circuits that  
4 remove waste heat from the combustion process and utilizes it to preheat  
5 boiler feedwater improving overall cycle efficiency and heat rate. The  
6 economizer has erosion and tube thinning which requires tubing  
7 replacements to maintain boiler reliability.
- 8 • Monroe Unit 2 turbine valves will be overhauled for \$3.3 million (Exhibit  
9 A-12, Schedule B5.1, page 7, line 200). Project scope includes the four (4)  
10 stop valves, four (4) control valve actuators, two (2) combined reheat stop  
11 valves, and four (4) intercept valves. The valves and components are worn  
12 and require overhaul for proper operation. These valves provide overspeed  
13 protection for the turbine and prevent possible catastrophic failure.
- 14 • The crossover expansion joints on the Monroe Unit 2 LPA and LPB turbines  
15 will be replaced for \$3.1 million (Exhibit A-12, Schedule B5.1, page 7, line  
16 201). The crossover expansion joint is original equipment to the plant. The  
17 replacements are based on near-term failure risk which would affect unit  
18 reliability, efficiency, and result in a safety risk to plant personnel.
- 19 • Monroe Unit 2 FGD expansion joints will be replaced for \$3.0 million  
20 (Exhibit A-12, Schedule B5.1, page 7, line 202). The replacements are  
21 based on near term failure risk which would affect unit reliability, efficiency,  
22 and result in a safety risk to plant personnel.
- 23 • The Monroe Unit 2 south boiler feed pump turbine condenser will be retubed  
24 for \$1.5 million (Exhibit A-12, Schedule B5.1, page 7, line 203). A  
25 significant increase in tube failures in the condenser were identified,



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- 1 resulting in 22 percent of the condenser tubes being plugged. The condenser  
2 requires retubing to keep the boiler feed pump turbine in service.
- 3 • The Monroe Unit 2 station air dryer (Exhibit A-12, Schedule B5.1, page 7,  
4 line 204) will be installed for \$1.4 million. Station air dryers provide dry air  
5 to plant equipment to meet their equipment specifications and prevent  
6 premature equipment failures. The current system is past the manufacturer's  
7 expected life, and reliability and performance have degraded. The  
8 replacement station air dryer will restore the reliability and moisture removal  
9 performance of the system.
- 10 • The Monroe Unit 2 generator relays will be replaced for \$1.2 million  
11 (Exhibit A-12, Schedule B5.1, page 7, line 205). The current relays are  
12 original 1970s vintage electromechanical relays, which have been failing,  
13 are out of tolerance, and have been found in the failed state. The current  
14 equipment is prone to nuisance generator trips when actual faults are not  
15 present and could fail to trip the generator when an actual fault does occur,  
16 putting unit equipment at risk of severe damage. The current relays will be  
17 replaced with microprocessor relays capable of providing information to  
18 support diagnosing electrical faults.
- 19 • Monroe Unit 3 SCR catalyst modules on layer 1 will be replaced for \$3.5  
20 million (Exhibit A-12, Schedule B5.1, page 7, line 206). The catalyst  
21 module replacements are required to maintain compliance with air permit  
22 emission limits for NOx and ammonia slip guidelines.
- 23 • The transfer chute between CV-09 conveyor and CR-02 will be replaced for  
24 \$3.4 million (Exhibit A-12, Schedule B5.1, page 7, line 207). Transfer  
25 chutes are used throughout the fuel supply system to direct coal from one

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1 conveyor belt to another on the path from the coal piles to the powerhouse.  
2 The current chute tends to generate significant amounts of coal dust during  
3 periods of dry coal and is prone to pluggage during periods of wet coal. The  
4 new discharge chute technology will minimize combustible coal dust and  
5 coal spillage and ensure compliance with NFPA guidelines.  
6 • Monroe fuel supply dust collectors 04, 16 and 05 will be replaced for \$3.0  
7 million, \$2.9 million and \$1.1 million, respectively (Exhibit A-12, Schedule  
8 B5.1, page 7, lines 208, 209 and 210). The prior system was  
9 decommissioned as it no longer met the NFPA guidelines. The current  
10 process is to washdown the transfer house. However, this still leaves  
11 equipment exposed to coal dust. The new dry-type dust collector  
12 replacement will mitigate combustible coal dust and comply with the NFPA  
13 combustible dust guidelines.

14

15 **Energy Supply's Routine Capital Expenditures - Hydraulic Power Generation**

16 **Q68. What were the Company's routine capital expenditures in 2023 for Hydraulic**  
17 **Power generation (Ludington)?**

18 A68. During 2023, the Company's Energy Supply group's routine capital expenditures  
19 for the Ludington Pumped Storage facility were \$10.1 million as shown on Exhibit  
20 A-12, Schedule B5.1, page 3 of 9, line 7, column (b). Expenditures were related to  
21 the replacements of the powerhouse roof, lower penstock expansion joint, control  
22 relays, motor control centers, barrier net panels, and other unit maintenance.

23

24 **Q69. What will be the Company's routine capital expenditures for Hydraulic Power**  
25 **Generation (Ludington) in the 24 months ending December 31, 2025?**

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1 A69. During the 24 months ending December 31, 2025, Energy Supply routine capital  
2 expenditures for the Ludington Pumped Storage facility are projected to be \$17.9  
3 million as shown on Exhibit A-12, Schedule B5.1, page 3 of 9, line 7, column (e).  
4 Investments will be related to the replacements of control relays, lower penstock  
5 expansion joint, governors, motor control centers, a station water isolation valve, a  
6 sump pump, and other unit maintenance.

7

8 **Q70. What will be the Company's routine capital expenditures for Hydraulic Power**  
9 **Generation (Ludington) in the projected test year, the 12 months ending**  
10 **December 31, 2026?**

11 A70. During the 12 months ending December 31, 2026, the Company's routine capital  
12 expenditures for the Ludington Pumped Storage facility are projected to be \$12.3  
13 million as shown on Exhibit A-12, Schedule B5.1, page 3 of 9, line 7, column (f).  
14 Investments will be related to replacements of control relays, governors, motor  
15 control centers, the station power transformer, the intake gate and gate house, and  
16 other unit maintenance.

17

18 **Energy Supply's Routine Capital Expenditures - Other Power Generation**

19 **Q71. What bulk electric system support is provided by the peaking units included**  
20 **in Other Power Generation?**

21 A71. DTE Electric's fleet of peaking units are primarily valued for their capacity and  
22 ability to start up quickly and reliably in response to high peak customer demand  
23 and the variable circumstances on the Company's distribution system throughout  
24 its 7,600 square mile service territory. The safe, reliable operation of these peaking

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1 units is also an important factor in system balancing as additional intermittent  
2 resources are integrated into the grid.

3 **Q72. What were the Company's routine capital expenditures greater than \$1**  
4 **million in 2023 for Other Power Generation?**

5 A72. During 2023, the Company's routine capital expenditures for Other Power  
6 Generation units was \$47.0 million as shown on Exhibit A-12, Schedule B5.1, page  
7 3 of 9, lines 8-9, column (b). These expenditures include the following projects  
8 that individually exceeded \$1 million as detailed on page 4 of Exhibit A-12,  
9 Schedule B5.1:

- 10 • A Belle River 12-2 Peaker major overhaul outage was completed in 2023 for  
11 \$5.4 million (Exhibit A-12, Schedule B5.1, page 4, line 49). Additionally,  
12 the Greenwood 11-1 Peaker prepared for a 2024 major overhaul outage with  
13 engineering for \$1.3 million (Exhibit A-12, Schedule B5.1, page 4, line 52).  
14 This work is required for continued safe and reliable operation. Major  
15 maintenance intervals for gas turbines are established by the cumulative run  
16 hours and startup sequences experienced.
- 17 • The generator field was replaced on Belle River 12-2 (Exhibit A-12,  
18 Schedule B5.1, page 4, line 50) Peaker for \$1.4 million. This work was  
19 required for continued safe and reliable operation. Generator field  
20 replacements for gas turbines are established by the years of service and the  
21 frequency of start/stop cycles experienced by the unit.
- 22 • During the annual borescope inspection, emergent work was found to be  
23 required for the Belle River 13-1 Peaker Modified Hot Gas Path Overhaul  
24 for \$1.2 million (Exhibit A-12, Schedule B5.1, page 4, line 51). Hardware

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- 1 damage as the result of a failed transition piece end seal, which was found  
2 in good condition in the spring borescope inspection, was identified within  
3 the combustion and turbine sections. The transition seal was repaired,  
4 damaged 1st stage buckets were replaced, and minor damage on the 2nd and  
5 3rd stage turbine hardware was addressed.
- 6 • Replacing the exhaust silencers (baffles) on the Greenwood 11-1, 11-2, and  
7 12-1 Peakers began for \$1.3 million (Exhibit A-12, Schedule B5.1, page 4,  
8 line 53). The previous exhaust silencer baffles were degrading, and  
9 inspections identified metal debris and insulation material loss. The new  
10 baffles will improve sound attenuation of the unit, supporting permit  
11 compliance.
  - 12 • The generator field was replaced on the Northeast 13-2 Peaker for \$1.6  
13 million (Exhibit A-12, Schedule B5.1, page 4, line 54). This work was  
14 required to replace failed equipment and for continued safe and reliable  
15 operation. The generator field failed in 2022 and required replacement.
  - 16 • The Renaissance Unit 4 Peaker generator stator was rewound, and the rotor  
17 was replaced (Exhibit A-12, Schedule B5.1, page 4, line 55) for \$9.0 million.  
18 This rewind and rotor replacement was required because Renaissance Unit  
19 4 experienced a ground fault on the generator. During the inspection phase  
20 of the project, the neutral side main leads were found to have flashed  
21 between two phases, damaging insulation material and stator components.
  - 22 • The Renaissance Unit 3 Peaker completed a major overhaul for \$7.1 million  
23 (Exhibit A-12, Schedule B5.1, page 4, line 56). This was the first major  
24 maintenance since the unit was installed in 2002. The overhaul was required  
25 to allow the return of the peaker to service and included corrective

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- 1 maintenance on the compressor, combustion system, gas turbine blading,  
2 and hot gas path.
- 3 • During the annual borescope inspection, emergent work was found to be  
4 required for the Renaissance Unit 2 Peaker Modified Hot Gas Path Overhaul  
5 for \$3.9 million (Exhibit A-12, Schedule B5.1, page 4, line 57). Significant  
6 erosion with material loss was identified at the row 1 turbine vane trailing  
7 edges and at the row 1 turbine blade leading edges. Replacement of the row  
8 1 vane and blade assemblies was completed to address these issues.
  - 9 • The exhaust silencer baffles on the Renaissance Unit 2 (Exhibit A-12,  
10 Schedule B5.1, page 4, line 58) and Renaissance Unit 4 (Exhibit A-12,  
11 Schedule B5.1, page 4, line 60) Peakers were replaced for \$2.3 million and  
12 \$1.7 million, respectively. The previous exhaust silencer baffles were  
13 degrading and inspections identified metal debris and insulation material  
14 loss. The new baffles improved sound attenuation of the unit, supporting  
15 permit compliance.
  - 16 • \$1.8 million was spent to complete the Renaissance Unit 3 exhaust cylinder  
17 and manifold replacement (Exhibit A-12, Schedule B5.1, page 4, line 59).  
18 Exhaust system inspections completed on Renaissance Unit 3 revealed  
19 degradation of components and struts, material distress, and weld cracks.  
20 The inspections indicated the integrity of the exhaust turbine casing and  
21 cylinder were close to failure and required replacement.
  - 22 • Procurement of a Renaissance unit compatible spare main unit transformer  
23 was completed for \$1.2 million (Exhibit A-12, Schedule B5.1, page 4, line  
24 61). This transformer was needed for fleet reliability in the event of a failure  
25 of any one of the Renaissance main unit transformers.

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No.

**Q73. What are the routine projects with projected capital expenditures greater than \$1 million in 2024 for Other Power Generation?**

A73. Planned 2024 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 2024 for Other Power Generation units include:

- Procurement of a spare Blue Water Energy Center steam turbine generator transformer and combustion turbine transformer began for \$4.1 million and \$3.8 million, respectively (Exhibit A-12, Schedule B5.1, page 5, line 112 and 113). There are no existing transformers available that meet the electrical configuration requirements for the Blue Water Energy Center steam turbine generator and combustion turbine transformers. It is both reasonable and prudent to initiate the procurement of spare transformers, especially considering the multi-year manufacturing time requirement. A failed transformer could cause an extended forced outage of 2-3 years.
- \$2.2 million was spent to continue the Blue Water Energy Center circulating water pumps enclosure project (Exhibit A-12, Schedule B5.1, page 5, line 114). Although the plant is designed to operate down to 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 can 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, can also experience heavy icing. Enclosing the circulating water

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- 1 pump, supporting systems, and the cooling tower stairs protects them from  
2 the cooling tower plume during the winter and will prevent forced outages  
3 and reduce the risk of employee injury.
- 4 • A combustion overhaul was completed on the Belle River 13-1 Peaker for  
5 \$1.3 million (Exhibit A-12, Schedule B5.1, page 5, line 115). The project  
6 included the replacement of fuel nozzles, support housings, combustor  
7 baskets, transition pieces, as well as inner and outer transition seals. This  
8 work was required for continued safe and reliable operation. Major  
9 maintenance intervals for gas turbines are established by the cumulative run  
10 hours and startup sequences experienced.
  - 11 • Greenwood 11-1 Peaker major overhaul outage was completed for \$6.9  
12 million (Exhibit A-12, Schedule B5.1, page 5, line 116). This work was  
13 required for continued safe and reliable operation. Major maintenance  
14 intervals for gas turbines are established by the cumulative run hours and  
15 startup sequences experienced.
  - 16 • The generator field was replaced on the Greenwood 11-1 Peaker (Exhibit A-  
17 12, Schedule B5.1, page 5, line 117) for \$1.5 million. This work was  
18 required to ensure continued safe and reliable operation. Generator field  
19 replacements for gas turbines are established by the years of service and the  
20 frequency of start/stop cycles experienced by the unit.
  - 21 • Greenwood 12-1 Peaker major overhaul outage material was purchased for  
22 \$1.1 million (Exhibit A-12, Schedule B5.1, page 5, line 118). This material  
23 is required in preparation of the 2026 outage which will continue the safe  
24 and reliable operation of the unit. Major maintenance intervals for gas



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- 1 turbines are established by the cumulative run hours and startup sequences
- 2 experienced.
- 3 • The exhaust silencers (baffles) on the Greenwood 11-1, 11-2, and 12-1
- 4 Peakers had their replacement completed for \$1.1 million (Exhibit A-12,
- 5 Schedule B5.1, page 5, line 119). The previous exhaust silencer baffles were
- 6 degrading and inspections identified metal debris and insulation material
- 7 loss. The new baffles will improve sound attenuation of the unit, supporting
- 8 permit compliance.
- 9 • The Renaissance Unit 3 (Exhibit A-12, Schedule B5.1, page 5, line 120) and
- 10 Renaissance Unit 1 (Exhibit A-12, Schedule B5.1, page 5, line 121) Peakers
- 11 generator stator rewind and rotor replacements were completed for \$7.4
- 12 million each. Previous inspections on Renaissance units revealed a high
- 13 level of risk for in-service faults that need to be addressed to prevent failure.
- 14 Accordingly, these units required a generator stator rewind and rotor
- 15 replacement to avoid an in-service failure.
- 16 • A combustion overhaul was performed on Renaissance Unit 4 (Exhibit A-
- 17 12, Schedule B5.1, page 5, line 122) and materials were purchased for a
- 18 combustion overhaul of Renaissance Unit 2 (Exhibit A-12, Schedule B5.1,
- 19 page 5, line 123) for \$5.0 million and \$3.0 million, respectively. The
- 20 projects include the replacement of fuel nozzles, support housings,
- 21 combustor baskets, transition pieces, as well as inner and outer transition
- 22 seals. This work was required for continued safe and reliable operation.
- 23 Major maintenance intervals for gas turbines are established by the
- 24 cumulative run hours and startup sequences experienced.

Line  
No.

**Q74. What are the routine projects with projected capital expenditures greater than \$1 million in 2025 for Other Power Generation?**

A74. Planned Other Power Generation maintenance projects greater than \$1 million in 2025 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 2025 for Other Power Generation units include:

- Twelve (12) variable frequency drive fan motors will be procured for the Blue Water Energy Center cooling tower for \$2.9 million (Exhibit A-12, Schedule B5.1, page 6, line 160). During the past two winters, significant ice build-up in and around the cooling tower has caused safety hazards. Variable frequency drives allow air flow to be adjusted, which is the most effective means of controlling ice formation, limiting damage due to ice fall, and maintaining proper condenser cooling water temperature.
- \$1.5 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 161). As previously discussed, 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.
- \$1.1 million will be spent on high pressure gas line bath heater controls (Exhibit A-12, Schedule B5.1, page 6, line 162). This heater counteracts the cold natural gas temperatures that result from gas line pressure reductions. The new controls will prevent potential short cycling that has caused overpressurization within the equipment housing resulting in an unsafe operating condition for employees.

Line  
No.

- 1           • Greenwood 11-1 Peaker major overhaul outage will be completed for \$1.1
- 2           million (Exhibit A-12, Schedule B5.1, page 6, line 163). This major
- 3           overhaul is required to continue the safe and reliable operation of the unit.
- 4           Major maintenance intervals for gas turbines are established by the
- 5           cumulative run hours and startup sequences experienced.
- 6           • Greenwood 11-2 Peaker major overhaul outage material will be purchased
- 7           for \$1.0 million (Exhibit A-12, Schedule B5.1, page 6, line 164). This
- 8           material is required in preparation for the 2026 outage which will continue
- 9           the safe and reliable operation of the unit. Major maintenance intervals for
- 10          gas turbines are established by the cumulative run hours and startup
- 11          sequences experienced.
- 12          • \$15.9 million will be spent to perform a modified major overhaul on
- 13          Renaissance Unit 4 (Exhibit A-12, Schedule B5.1, page 6, line 165). In
- 14          December 2024, the unit experienced a reignition of fuel resulting in damage
- 15          to the unit. The modified major overhaul will include replacement of
- 16          multiple compressor blade rows, combustion hardware, and multiple turbine
- 17          blade rows. The Company has filed an insurance claim that is expected to
- 18          cover a large portion of the repair work. The expenditures included in my
- 19          exhibit only include expenditures expected to be not covered by insurance.
- 20          It is reasonable and prudent to perform the required repairs and return
- 21          Renaissance Unit 4 to service.
- 22          • Separate from the Renaissance Unit 4 Peaker modified major overhaul,
- 23          \$11.4 million will be spent to complete the unit's exhaust cylinder and
- 24          manifold replacement (Exhibit A-12, Schedule B5.1, page 6, line 166).
- 25          Exhaust system inspections completed on Renaissance Unit 4 and sister units

Line  
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1 have revealed degradation of components and struts, material distress, and  
2 weld cracks. The integrity of the exhaust turbine casing and cylinder are at  
3 risk of failure and require replacement.

4 • The Renaissance Unit 2 Peaker generator rotor will be replaced for \$2.6  
5 million (Exhibit A-12, Schedule B5.1, page 6, line 167). This generator  
6 work must be completed to correct the degradation of insulation and copper  
7 and reduce the risk of extensive damage should a failure occur.

8 • A combustion overhaul will be completed on Renaissance Unit 2 (Exhibit  
9 A-12, Schedule B5.1, page 6, line 168) for \$1.3 million. The project includes  
10 the replacement of fuel nozzles, support housings, combustor baskets,  
11 transition pieces, as well as inner and outer transition seals. This work is  
12 required for continued safe and reliable operation. Major maintenance  
13 intervals for gas turbines are established by the cumulative run hours and  
14 startup sequences experienced.

15 • A blackstart peaker starting system will be replaced for \$3.2 million (Exhibit  
16 A-12, Schedule B5.1, page 6, line 169) and materials in preparation for  
17 replacing a second black start unit's starting system will be procured for \$1.4  
18 million (Exhibit A-12, Schedule B5.1, page 6, line 170). The unit starting  
19 systems are obsolete and require replacement with an up-to-date design.  
20 Components of the existing unit starting systems, installed in 1999, are no  
21 longer supported by the OEM and/or other suppliers.

22

23 **Q75. What are the routine projects with projected capital expenditures greater than**  
24 **\$1 million in 2026 for Other Power Generation?**

Line  
No.

1 A75. Planned Other Power Generation maintenance projects greater than \$1 million in  
2 2026 are detailed on page 7 of 9 in Exhibit A-12, Schedule B5.1 and described  
3 below. The individual projects with greater than \$1 million of expenditures in 2026  
4 for Other Power Generation units include:

- 5 • Hot gas path overhauls will be performed on the two Blue Water Energy  
6 Center combustion turbines, CTG11 and CTG12, for \$22.9 million and  
7 \$23.8 million, respectively (Exhibit A-12, Schedule B5.1, page 7, lines 211  
8 and 213). The overhauls are being completed as part of a long-term service  
9 agreement with the OEM. Major maintenance intervals for gas turbines are  
10 established by the cumulative run hours and startup sequences experienced.
- 11 • The Blue Water Energy Center CTG 11 and CTG 12 air inlet filters will be  
12 replaced for \$1.1 million each (Exhibit A-12, Schedule B5.1, page 7, lines  
13 212 and 214). The air inlet filters protect the sensitive and complex interior  
14 components of the gas turbine system to ensure proper performance and  
15 lifespan of the equipment. Filter replacement is recommended every four  
16 years and will be due in 2026.
- 17 • Procurement of spare transformers for the BWEC steam turbine generator  
18 and a combustion turbine generator will continue for \$4.8 million each  
19 (Exhibit A-12, Schedule B5.1, page 7, lines 215 and 216). There are no  
20 existing transformers available that meet the electrical configuration  
21 requirements for the Blue Water Energy Center steam turbine generator and  
22 combustion turbine transformers. It is both reasonable and prudent to initiate  
23 the procurement of spare transformers, especially considering the multi-year  
24 manufacturing time requirement. A failed transformer could cause an  
25 extended forced outage of 2-3 years.

Line  
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- 1 • Variable frequency drive fan motors will be installed on the BWEC cooling  
2 tower for \$2.2 million (Exhibit A-12, Schedule B5.1, page 7, line 217).  
3 During the past two winters, significant ice build-up in and around the  
4 cooling tower has caused safety hazards. Variable frequency drives allow air  
5 flow to be adjusted, which is the most effective means of controlling ice  
6 formation, limiting damage due to ice fall, and maintaining proper condenser  
7 cooling water temperature.
- 8 • The BWEC control server will be upgraded for \$1.0 million (Exhibit A-12,  
9 Schedule B5.1, page 7, line 218). The current version of the Windows  
10 Operating System at Blue Water Energy Center is based on Microsoft  
11 Windows Server circa 2012, the latest version validated by General Electric  
12 at the time the Blue Water project commenced. That version needs to be  
13 upgraded to maintain software security and reliability protocols.
- 14 • BWEC steam turbine valves will be overhauled for \$6.3 million (Exhibit A-  
15 12, Schedule B5.1, page 7, line 219). The valves, based on run times, are  
16 expected to be worn and require overhaul for proper operation. These valves  
17 provide overspeed protection for the turbine and prevent possible  
18 catastrophic failure.
- 19 • The control systems will be replaced on the five Belle River DG11 Peakers  
20 for \$1.5 million (Exhibit A-12, Schedule B5.1, page 7, line 220). The current  
21 control systems are original, 1960s-vintage equipment and are causing  
22 multiple startup failures. Additionally, components of the existing control  
23 system are no longer supported by the OEM and/or other suppliers.
- 24 • Hot gas path overhauls will be performed on Dean Peakers 11-1 and 11-2  
25 for \$2.4 million each (Exhibit A-12, Schedule B5.1, page 7, lines 221 and

Line  
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- 1 222). Industry wide, major maintenance intervals including hot gas path  
2 overhauls for gas turbines are established by the cumulative run hours and  
3 startup sequences experienced. The planned scope includes replacement of  
4 liners and caps, fuel nozzle tips, primary fuel nozzle assembly, transitions,  
5 1st stage blades/buckets, 2nd stage blades/buckets, 3rd stage blades/buckets,  
6 1st stage vanes/nozzles, 2nd stage vanes/nozzles, 3rd stage vanes/nozzles,  
7 1st stage shroud, 2nd stage shroud, and 3rd stage shroud.
- 8 • Exhaust silencers (baffles) will be replaced on Delray 11-1 and 12-1 peakers  
9 for \$1.9 million (Exhibit A-12, Schedule B5.1, page 7, line 223). The  
10 exhaust silencer baffles are degrading, and inspections identified metal  
11 debris and insulation material loss. The new baffles will improve sound  
12 attenuation of the unit, supporting permit compliance.
- 13 • Major overhauls will be performed on Greenwood 11-2 and Greenwood 12-  
14 1 Peakers for \$8.3 million and \$7.9 million, respectively (Exhibit A-12,  
15 Schedule B5.1, page 7, lines 224 and 225). This work is required for  
16 continued safe and reliable operation. Major maintenance intervals for gas  
17 turbines are established by the cumulative run hours and startup sequences  
18 experienced. This will be the first major overhaul for both units since  
19 installation in 1999.
- 20 • The generator fields on Greenwood 12-1 and Greenwood 11-2 Peakers will  
21 be replaced for \$2.0 million and \$1.8 million, respectively (Exhibit A-12,  
22 Schedule B5.1, page 7, lines 226 and 227). Generator field replacements for  
23 gas turbines are established by the years of service and the frequency of  
24 start/stop cycles experienced by the unit. This will be the first time the  
25 generator fields are being replaced since the units were installed in 1999.

Line  
No.

- 1           • Material will be procured for a combustion overhaul on Renaissance Unit 3
- 2           Peaker for \$3.8 million (Exhibit A-12, Schedule B5.1, page 7, line 228). The
- 3           project includes the replacement of fuel nozzles, support housings,
- 4           combustor baskets, transition pieces, as well as inner and outer transition
- 5           seals. This work is required for continued safe and reliable operation. Major
- 6           maintenance intervals for gas turbines are established by the cumulative run
- 7           hours and startup sequences experienced.
- 8           • The starting system on a blackstart peaker will be replaced for \$2.0 million
- 9           (Exhibit A-12, Schedule B5.1, page 7, line 229). The unit starting system is
- 10          obsolete and requires replacement with an up-to-date design. Components
- 11          of the existing unit starting system, installed in 1999, are no longer supported
- 12          by the OEM and/or other suppliers.

13

14   **Energy Supply's AFUDC Estimate**

15   **Q76. Do the capital expenditures you are supporting include an allowance for funds**  
16   **used during construction (AFUDC)?**

17   A76. Yes, capital expenditures include an AFUDC for eligible projects that are in  
18   Construction Work in Progress (CWIP). At the direction of Company Witness  
19   Uzenski, AFUDC is applied to projects greater than \$50,000 and lasting more than  
20   six months, except for large environmental projects which are exempt from  
21   AFUDC treatment.

22

23   **Q77. How much AFUDC is assumed in the projected test period for Energy Supply?**

24   A77. AFUDC for Energy Supply is included on Exhibit A-12, Schedule B5.1, page 8 of  
25   9. As shown on line 13, column (c), the AFUDC is projected to be \$15.4 million



Line  
No.

1 for the 12-month period ending December 31, 2026. A historical trend is used to  
2 estimate AFUDC on routine capital since the mix of eligible projects is consistent  
3 year-to-year, while the AFUDC is calculated specifically on a project-by-project  
4 basis for eligible non-routine projects. The authorized cost of capital rate used is  
5 5.69% consistent with the January 23, 2025 Order in Case No. U-21534. For  
6 additional details on AFUDC refer to Company Witness Uzenski's direct  
7 testimony.

8  
9 **Energy Supply's Removal Costs, Plant in Service and CWIP Forecast**

10 **Q78. What is provided on the schedule entitled Removal Costs, Plant in Service, and**  
11 **CWIP schedule on page 9 of 9 of Exhibit A-12, Schedule B5.1?**

12 A78. This schedule provides a breakdown of plant activities used by Witness Uzenski to  
13 forecast Plant in Service, Accumulated Depreciation, and CWIP on the projected  
14 balance sheet. Capital expenditures consistent with Exhibit A-12, Schedule B5.1,  
15 page 1 are summarized in columns (c) through (f). Column (b) includes a  
16 corresponding in-service assumption: "Annual" is indicated for categories of plant  
17 spend that are generally unitized within the year of spend, while a specific in-  
18 service date is used for projects that remain in CWIP for more than a year before  
19 moving into Plant in Service.

20  
21 Column (g) includes an estimated percentage of removal costs that are included  
22 within the capital expenditures. Removal costs, as discussed by Witness Uzenski,  
23 are charged to Accumulated Depreciation rather than Plant/ CWIP and are therefore  
24 not depreciable. Removal cost of 15% based on the historical trend of removals as  
25 a component of capital expenditures is applied to routine expenditures on lines 2

Line  
No.

1 through 6. 100% is applied to specific removal and decommissioning projects on  
2 lines 9, 10, and 22 and 0% is applied to non-removal projects on lines 11 and 12.  
3 Finally, 0% is applied to new build projects on lines 15 through 21 since there is no  
4 related removal work.

5  
6 Column (h) through (j) reflect calculated removal costs based on projected Capital  
7 Expenditures in columns (d) through (f) multiplied by the removal cost % in column  
8 (g). The remaining Capital Expenditures will appear in Plant in Service columns  
9 (k) through (m) if in-service assumption is “Annual”, or CWIP columns (n) through  
10 (p) until the date of in-service as indicated in column (b). At that time, cumulative  
11 spend including the historical period is transferred to in-service (excluding the  
12 removal cost estimate). Major projects with a long lead time also reflect spend  
13 from earlier years that will be transferred out of CWIP into Plant in Service on the  
14 in-service date.

15 **Part III – Energy Supply Operation and Maintenance Expenses**

16 **Q79. What is the process used to prepare the Energy Supply operating and**  
17 **maintenance (O&M) projected level of expense?**

18 A79. Projected O&M expense is developed by taking historical test year O&M  
19 expenditure data and adjusting for any known projected period changes. Plant level  
20 changes include labor and material cost increases, cost variations related to  
21 environmental equipment operation, non-periodic maintenance cost variations  
22 driven by predictive maintenance programs, and other known changes.

23

Line  
No.

1 The overall Energy Supply O&M projection for steam, hydraulic, and other  
2 generation assets is developed by adjusting the actual historical test year (2023)  
3 results for rate case adjustments between witnesses, normalization adjustments to  
4 the 2023 data, and known and measurable adjustments to handle O&M changes (up  
5 or down). O&M projections in this case do not include funding for Energy Supply  
6 renewable generation wind and solar assets that are handled in other regulatory  
7 filings.

8  
9 Energy Supply operations expenses are those associated with day-to-day operation  
10 of the Company's generating units, including certain Account 501 fuel handling  
11 expenses. Energy Supply maintenance expenses are associated with periodic  
12 outages, non-periodic outages, and other maintenance activities. Other  
13 maintenance activities include standard day-to-day work to maintain plant  
14 equipment, such as inspections, servicing, and minor maintenance that does not  
15 require the unit to be taken offline to complete.

16  
17 Energy Supply O&M is presented in three major cost categories as shown below:

- 18 • Steam Power Generation  
19 • Hydraulic Power Generation  
20 • Other Power Generation

21

22 **Q80. What were Energy Supply's historical O&M Expenditures for 2023 for Steam**  
23 **Power Generation?**

24 A80. During 2023, Steam Power Generation adjusted O&M expenses totaled \$173.3  
25 million as shown on Exhibit A-13 Schedule C5.1, line 19, column (h). This was

Line  
No.

1 comprised of \$71.1 million in operations costs and \$102.3 million in maintenance  
2 costs. The \$7.5 million of Steam Power Generation O&M that relates to Fuel  
3 Supply and Midwest Energy Resources Company (MERC) Fuel Handling is  
4 sponsored by Company Witness Milo on Exhibit A-13, Schedule C5.2 and is  
5 subtracted on line 20 (Note 1), resulting in remaining Steam Power Generation  
6 adjusted O&M in the amount of \$165.8 million.

7

8 **Q81. Can you provide an overview of Exhibit A-13, Schedule C5.1?**

9 A81. Exhibit A-13, Schedule C5.1 shows total projected test period O&M for Steam  
10 Power Generation by starting with the 2023 actual O&M expenses and adjusting  
11 for rate case eliminations, normalization/other adjustments, and inflation  
12 adjustments. The historical adjustment is required to determine the portion of the  
13 2023 O&M expenses that will reoccur in the 12-month period ending December  
14 31, 2026. The historical adjustment credit of \$0.072 million is shown in note 4.  
15 The normalization adjustment expense of \$20.4 million is shown in note 5. There  
16 is also a projected adjustment of \$13.8 million required in column (l) and shown in  
17 note 7 to project the O&M required in the 12-month forecasted test period ending  
18 December 31, 2026.

19

20 **Q82. What major O&M expense categories are found in Exhibit A-13, Schedule**  
21 **C5.1?**

22 A82. The expenses shown in Exhibit A-13, Schedule C5.1 are categorized into the major  
23 categories of operations and maintenance consistent with FERC accounting  
24 guidelines.

25

Line  
No.

1 Operations account 500 includes the cost of plant management for the individual  
2 plant sites, their supporting staffs, and the Energy Supply Engineering Support  
3 Organization. Plant management includes plant site director, area managers, and  
4 administrative support. The major supporting staffs in this area are the technical  
5 and engineering personnel associated with problem solving daily plant operating  
6 issues, obtaining and interpreting test data, and developing long-term operating and  
7 maintenance plans to maintain plant availability and efficiency.

8  
9 Operations account 501 "Fuel Handling" includes expenses incurred for coal train  
10 and vessel unloading, ash disposal, coal pile management, and mobile equipment  
11 operations. Depending on plant site and delivery options, plants maintain and  
12 manage a coal pile inventory that can vary over many months. Larger coal pile  
13 inventories are required at the Belle River Power Plant at the end of December to  
14 ensure adequate coal supplies when vessel deliveries cannot be obtained due to  
15 winter ice on the Great Lakes.

16 Accounts 502 and 505 represent operations personnel and materials expenses  
17 associated with direct operating supervision and control of boiler, turbine,  
18 generator, water, and environmental control systems. Shift supervisor and control  
19 room supervising operators are key to the successful steam power generation unit  
20 operations that are required to ensure adequate and cost-efficient production of  
21 electrical energy for our customers. Their labor expenses are captured in these  
22 accounts.

Line  
No.

1 Account 506 “Misc. Steam Power Expenses” includes Instrument and Controls  
2 personnel to troubleshoot and calibrate the vast array of complex instruments and  
3 controls found on steam generating units. Also included in this account are  
4 operations of all common equipment such as water, air, and cooling equipment  
5 systems. Plant buildings and grounds cleaning, landscaping, snow removal, and  
6 maintenance are also captured in this account.

7  
8 Maintenance accounts 510 through 514 capture expenses associated with planned  
9 and unplanned maintenance activities. These expenses mostly consist of the  
10 planned maintenance activities that generally occur on a two to five-year interval  
11 on all boiler systems and on a six to ten-year interval on turbine systems. Account  
12 510 captures management of the plant maintenance area including area managers  
13 and general foremen. Account 511 covers maintenance of common infrastructure  
14 areas such as roofs, windows, and roads. The major area of expense captured in  
15 account 512 “Maintenance of Boilers” includes maintenance expenses for internal  
16 and external labor and all materials associated with planned and unplanned outage  
17 work on the boilers. The boiler maintenance scope of work includes the boilers, air  
18 and flue gas systems, ash handling, and fuel burning equipment. The major area of  
19 expense captured in account 513 “Maintenance of Electric Plant” includes internal  
20 and external labor and materials expenses associated with work on turbines. The  
21 major area of expense captured in account 514 “Maintenance of Misc. Steam Plant”  
22 includes internal and external labor and materials expenses for maintenance of all  
23 common equipment such as water, air, and cooling equipment systems.

Line  
No.

1   **Q83. Can you provide additional detail on the O&M expenses incurred for the**  
2       **Company's Steam Power Generation during 2023?**

3   A83. Yes. In the historic period of 2023, the Company spent \$165.8 million in Steam  
4       Power Generation O&M expenses after adjustments and reclassifications. A  
5       planned major periodic maintenance outage was executed in 2023 on Monroe Unit  
6       1. Also completed during 2023 were multiple short duration unit tune-up outages  
7       on various units to allow their continued efficient operation burning high  
8       percentages of lower sulfur coals. Costs for the portions of outages that occur in  
9       years other than 2023 will be captured in those years.

10

11       The other category of maintenance expenses incurred during the historic period  
12       were associated with regular plant maintenance while units were in operation or  
13       expenses to repair or replace equipment during a forced or unplanned unit outage.  
14       These short duration unplanned maintenance outages can generally be completed  
15       in three to seven days and will be experienced at varying intervals on all steam  
16       power generating units depending on the severity of the service cycles and the time  
17       elapsed since the last planned maintenance outage.

18   **Q84. Can you provide additional detail on the O&M expenses planned to be**  
19       **incurred for the Company's Steam Power Generation during 2026?**

20   A84. During the projected 12-month period ending December 31, 2026, the Company  
21       will execute major periodic maintenance outages on Belle River Unit 2 and Monroe  
22       Unit 2, and minor periodic maintenance on Monroe Unit 3. As in the historic  
23       period, short duration unit tune-up outages will also be completed on various steam  
24       power generation units to optimize continuing performance.

Line  
No.

1 **Q85. What adjustments were made to the historical test period amounts?**

2 A85. Fuel Handling O&M expenses recorded in Fuel Account 501 are added to Steam  
3 Power O&M in column (d). This amount includes Fuel Supply and MERC Fuel  
4 Handling for which an adjustment is made in column (e) to reclassify non-O&M  
5 fuel handling sponsored by Witness Milo (Note 3). In column (f) detailed in Note  
6 4, there is one (1) historical adjustment:

- 7 • A credit for \$72 thousand for the removal of corporate membership dues as  
8 supported by Witness Uzenski.

9

10 **Q86. Can you describe some of the benefits the Company and its customers realize**  
11 **through its memberships in industry associations, such as the Electric Power**  
12 **Research Institute (EPRI)?**

13 A86. Yes. As discussed by Witness Leslie, memberships in industry associations  
14 provide the Company access to benchmarking/best practices, research, and  
15 networking opportunities.

16

17 Specifically, with respect to EPRI, the Company collaborates with other utilities to  
18 fund technical projects that study and resolve critical industry issues. For instance,  
19 EPRI guidelines for boiler water chemistry and steam purity are commonly  
20 referenced to protect plant equipment and maintain reliable operations. In addition  
21 to the knowledge benefits gained through involvement in EPRI studies, the  
22 membership is cost-effective. The costs for the Company to perform even one of  
23 these projects would be greater than the cost of the membership.



Line  
No.

**Q87. Can you provide further explanation of the \$20.4 million historical test year normalization adjustment shown on Note 5 of Exhibit A-13, Schedule C5.1?**

A87. Yes. The \$20.4 million historical test year normalization adjustment shown in this exhibit reflects expenses that did not occur in the historical test year but are anticipated in the projected test year:

- The first adjustment of \$4.8 million is associated with the O&M savings of steam baseload units being in economic reserve shutdown during 2023. Typically, baseload units operate every hour they are available. However, based on the electric market conditions in 2023, the Company's steam baseload units spent more than a combined 200 days offline but available for generation. Due to this lower demand for generation, the steam baseload power plants experienced lower wear and tear, chemical usage, and labor than would otherwise have occurred. The Company is not forecasting elevated levels of reserve shutdowns on steam baseload units to repeat in 2026.
- The second adjustment of \$4.0 million is related to normalizing the forced outage spend. During 2023, steam units collectively spent less than \$10 million to perform forced outage repairs. In years prior, the steam units required \$12 to \$13 million (without considering inflation) of labor, maintenance and materials to perform necessary repairs related to forced outages.
- The third adjustment of \$11.6 million is related to normalizing the required periodic outage expenses. During 2023, only one major periodic outage was performed in the fossil steam generation fleet. Typically, at least two major periodic outages are performed annually in the fossil steam generation fleet.

Line  
No.

1 As a result, the 2023 periodic outage spend was well below the historical  
2 norm.

3

4 **Q88. What are the inflation factors shown in Note 6 of Exhibit A-13 Schedule C5.1?**

5 A88. Note 6 contains the inflation factors that are utilized to forecast the changes  
6 necessary to transition needed O&M funding from the historic test year of 2023 to  
7 the projected test year ending December 31, 2026. The labor and material inflation  
8 adjustment factor of 3.4% for 2024, 3.0% for 2025, and 3.1% for 2026 is supported  
9 by Witness Uzenski.

10

11 **Q89. Can you provide a further explanation of the \$13.8 million projected test year**  
12 **adjustment shown on Note 7 of Exhibit A-13, Schedule C5.1?**

13 A89. Yes. The \$13.8 million projected test year adjustment shown in this exhibit in eight  
14 parts reflects projected test year modifications needed to transition from 2023 actual  
15 O&M expenses to those required in the 12 months ending December 31, 2026:

16 • The first adjustment in this category is a credit of \$3.2 million and represents  
17 Energy Supply's estimated savings related to the Company's Voluntary  
18 Separation Incentive Program (VSIP). Witness Leslie explains this program  
19 and the associated savings in further detail.

20 • The second adjustment equaling \$2.2 million represents the expenses to  
21 monitor and maintain environmental compliance at two of the Company's  
22 retired coal-fired power plants, namely the River Rouge and St. Clair Power  
23 Plants. In 2023, environmental monitoring and compliance was performed  
24 under the active decommissioning projects at both plants. In 2026, the

Line  
No.

- 1 decommissioning projects will not be active and the costs to monitor and  
2 maintain environmental compliance will be expensed.
- 3 • The third adjustment equaling \$2.4 million represents the future costs to  
4 monitor groundwater at CCRMUs as required by the CCR regulations. As  
5 described above in the non-routine capital section of testimony, the  
6 Company will install groundwater monitoring wells at CCRMUs in 2025.  
7 Beginning in 2026, the Company will be analyzing groundwater samples  
8 from the newly installed wells on a routine basis.
  - 9 • The fourth adjustment is a credit of \$9.0 million and represents the reduction  
10 in O&M expense associated with Belle River Unit 1 converting from coal-  
11 fired to natural gas-fired operation. Natural gas-fired operations are  
12 expected to result in lower plant utilization (capacity factor) as compared to  
13 their operations as coal-fired units. As such, less equipment wear and tear  
14 expense is anticipated. Additionally, maintenance of certain equipment,  
15 such as coal mills and ash handling systems, will no longer be required after  
16 the natural gas conversion.
  - 17 • The fifth adjustment of \$4.7 million is associated with the restoration of the  
18 Belle River Unit 2 turbine support structure. Over time, vibration has  
19 developed in the intermediate and low pressure turbine assemblies.  
20 Restoration work is needed on the pedestal and associated supports to reduce  
21 turbine vibration. The work will mitigate potential unit forced outages due  
22 to turbine vibration-related trips and limited-load operation.
  - 23 • The sixth adjustment equaling \$5.8 million supports operational  
24 improvements on Belle River Unit 1 after converting to gas-fired operations.  
25 Opportunities exist to create a more flexible, efficient, and reliable natural-

Line  
No.

- 1 gas-fired peaking unit. Of the \$5.8 million projected, \$0.5 million would  
2 support achieving quicker startups and lower minimum load operation,  
3 similar to work that has been performed at Greenwood Power Plant. \$3.6  
4 million is projected to perform a chemical cleaning of the boiler tubes.  
5 Chemical cleanings remove deposits in boiler tubes, resulting in better heat  
6 transfer (higher boiler efficiency) and better long-term boiler reliability due  
7 to fewer tube leaks. Finally, \$1.6 million is projected to replace the ion  
8 exchange resin in all condensate polishers and demineralizers. Cycling  
9 operations causes more startups and hence more strain on boiler water  
10 treatment systems. Replacing the resin maintains the reliability and  
11 capability of the water treatment system which supports reliable plant  
12 operation.
- 13 • The seventh adjustment of \$7.7 million supports Monroe reliability  
14 maintenance. Of the total projected amount, \$2.2 million is forecasted for  
15 sootblower preventative maintenance. Sootblowers clean the outside surface  
16 of boiler tubes to maintain cleanliness and boiler efficiency. \$1.2 million is  
17 projected for coal mill maintenance inspections and repairs. Coal mills grind  
18 lump coal to a fine powder consistency suitable for efficient boiler  
19 combustion. Without maintenance, coal mills can perform poorly, resulting  
20 in lower boiler efficiency and unit derates. \$1.4 million is projected to  
21 support metal spray restoration of the induced draft (ID) fans. In recent  
22 years, erosion has been identified on ID fan blades on all four Monroe units.  
23 Correcting the material loss through metal spray restoration will maintain  
24 reliability and mitigate derates. \$0.9 million is projected to replace polisher  
25 resin. Replacing the resin maintains the reliability and capability of the

Line  
No.

1 water treatment system which supports reliable plant operation. Also, \$2.0  
2 million is forecasted to support cleanings of major equipment, including  
3 transformers, air heaters, and boiler backpasses. Removing ash and dirt from  
4 equipment supports efficient plant operations (lowers heat rate) and  
5 mitigates potential for unit derates and outages due to pluggage.

6 • Finally, the eighth adjustment totaling \$3.3 million is associated with  
7 maintenance of the Monroe Power Plant fuel unloading systems. After  
8 MERC closes in mid-2026, Monroe Power Plant will no longer receive low  
9 sulfur western coal by vessel from MERC. Instead, all western coal will  
10 come by rail. In order to maintain coal inventory at the plant, a very reliable  
11 rail car dumper and supporting equipment will be needed year-round. Due  
12 to the increase in rail deliveries and associated coal tonnages, additional  
13 maintenance will be needed on the rail car dumper equipment and other fuel  
14 supply coal handling equipment and infrastructure.

15

16 **Q90. Can you summarize Exhibit A-13, Schedule C5.4, entitled “Operations and**  
17 **Maintenance Expenses - Hydraulic Power Generation”?**

18 A90. Exhibit A-13, Schedule C5.4 represents DTE Electric’s share of the continuing  
19 operation and maintenance expense of the Ludington Pumped Storage facility. As  
20 a 49 percent owner of this facility, the Company incurs expenses for operating and  
21 maintaining the facility. The forecasts for these expenses through the projected test  
22 period are based on the historic labor and materials expenses adjusted for inflation.  
23 The labor and material inflation adjustment factor of 3.4% for 2024, 3.0% for 2025,  
24 and 3.1% for 2026 is supported by Witness Uzenski. No other historical or

Line  
No.

1 projected adjustments were made to Hydraulic Power Generation Projected  
2 Operation and Maintenance expenses.

3

4 **Q91. Can you summarize Exhibit A-13, Schedule C5.5, entitled “Operations and**  
5 **Maintenance Expenses - Other Power Generation?**

6 A91. Exhibit A-13, Schedule C5.5 represents DTE Electric’s peaker fleet O&M costs, as  
7 well as non-fuel O&M costs for Blue Water Energy Center, which began  
8 commercial operations in June 2022. DTE Electric owns and operates a number of  
9 peaking units ranging from 2.5 MW diesel-fueled engines to newer 163 MW natural  
10 gas-fired combustion turbines. The main driver of projections for these expenses  
11 through the projected test period is the labor and material required to support these  
12 peaker assets and Blue Water Energy Center. Included in this category will also be  
13 the labor expenses for the Generation Optimization and Integrated Resource  
14 Planning teams. The forecasts for these expenses through the projected test period  
15 are based on the historic labor and materials expenses as adjusted for inflation. The  
16 labor and material inflation adjustment factor of 3.4% for 2024, 3.0% for 2025, and  
17 3.1% for 2026 is supported by Witness Uzenski.

18

19 **Q92. Did you make any adjustments to the historical test period operations and**  
20 **maintenance expenses for other power generation?**

21 A92. Yes. \$40.4 million of total 2023 test year O&M, listed in column (d) of Exhibit A-  
22 13, Schedule C5.5 was removed because these expenses are related to the  
23 renewable energy program that are not associated with the instant case.

24

Line  
No.

1 **Q93. What normalizations were made to the historical test period amounts for other**  
2 **power generation?**

3 A93. In column (e) detailed in Note 2 of Exhibit A-13, Schedule C5.5, there is an upward  
4 adjustment for \$0.7 million in support of routine maintenance at Blue Water Energy  
5 Center. During the first two years of operation, equipment that fails will be covered  
6 under warranty with the OEM paying for the labor and materials to repair or replace  
7 failed components. In 2026, equipment that fails will not be covered by the  
8 warranty terms of the construction contract. The \$0.7 million normalization is an  
9 estimate of warranty compensated repair costs incurred in 2023.

10

11 **Q94. Can you provide a further explanation of the \$13.2 million projected test year**  
12 **adjustment shown on Note 4 of Exhibit A-13, Schedule C5.5?**

13 A94. Yes. The \$13.2 million projected test year adjustment shown in this exhibit in four  
14 parts reflects projected test year modifications needed to transition from 2023 actual  
15 O&M expenses to those required in the 12 months ending December 31, 2026:

- 16 • The first adjustment for \$3.6 million is in support of levelizing major  
17 periodic outage expenses for Blue Water Energy Center. The BWEC plant  
18 is anticipated to be removed from service every four years in order to  
19 perform major equipment maintenance. The first major outage will be in  
20 2026. The amount included in the adjustment is only the portion of O&M  
21 expense not covered by the contract service agreement with the OEM.
- 22 • The second adjustment of \$1.2 million is forecasted in 2026 to support  
23 Slocum BESS and Trenton Channel BESS operations. The Slocum BESS  
24 started commercial operations in February 2025. Trenton Channel BESS is  
25 anticipated to reach commercial operations in 2026.

Line  
No.

- 1           • The 3<sup>rd</sup> adjustment equaling \$8.6 million is related to increased peaker  
2           maintenance. Peaking unit operation has increased over the past few years  
3           which causes the frequency in which maintenance activities need to be  
4           performed to change. This is expected to continue into the future as the  
5           entire MISO generation portfolio transitions toward more intermittent  
6           resources which places a greater reliance on the Company's dispatchable  
7           peaker fleet. For example, capacity factors on large gas turbines more than  
8           doubled from 7% in the 2021-2022 period to 16% in the 2023-2024 period.  
9           As maintenance cycles are determined by operating hours and number of  
10          equipment starts, more starts and longer periods of operation during each  
11          start period require more frequent maintenance. This increase in O&M is  
12          required to support additional maintenance during 2026.
- 13          • Finally, the fourth adjustment is a decrease of \$0.2 million related to the  
14          retirement and suspension of operations of thirteen (13) peaker units (River  
15          Rouge 11-1 through 11-4 retirements, Slocum 11-1 through 11-5  
16          retirements, St. Clair 12-1 and 12-2 retirements, and Fermi 11-3 and Fermi  
17          11-4 suspension of operations).

18  
19   **Q95. What are your thoughts concerning the level of DTE Electric's historical and**  
20   **projected capital and O&M expenses contained in your testimony?**

21   A95. DTE Electric has been reasonable and prudent in past capital and O&M  
22   expenditures, and I anticipate this to continue through the projected test period and  
23   beyond. During this same timeframe, generation unit availability is managed  
24   through a rigorous process that continues to be focused on prudent capital and  
25   O&M expenditures. I believe that DTE Electric has fully justified as reasonable



Line  
No.

1 and prudent its request for recovery of the Energy Supply plant expenditures that  
2 are set forth in my testimony and associated exhibits.

3

4 **Q96. Does this complete your direct testimony?**

5 A96. 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- 21860

QUALIFICATIONS  
  
AND  
  
DIRECT TESTIMONY  
  
OF  
  
ROBERT J. LEE

**DTE ELECTRIC COMPANY**  
**QUALIFICATIONS AND DIRECT TESTIMONY OF ROBERT J. LEE**

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

2    A1.   My name is Robert J. Lee (he/him/his) and my business address is One Energy  
3           Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate  
4           Services, LLC within DTE's Environmental Management and Safety team and I  
5           am currently the Manager of Environmental Strategy for the Company.

6

7    **Q2.   On whose behalf are you testifying?**

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

9

10   **Q3.   What is your educational background?**

11   A3.   I received a Bachelor of Science Degree in Geology in 1992 and a Master of  
12          Science Degree in Environmental Geochemistry in 1994 from the University of  
13          Wales.

14

15   **Q4.   What is your work experience?**

16   A4.   Since completing my formal education, I have practiced continuously in the  
17          environmental field with a focus on State and Federal programs mostly in  
18          Michigan. My past and current responsibilities include management of several  
19          environmental program areas, including Effluent Limitations Guidelines (ELG)  
20          and water permit management, Coal Combustion Residual (CCR) program  
21          management, remediation program management, State and Federal construction  
22          permit programs, and coal plant retirement. Additionally, I have State and Federal  
23          level experience supporting and developing legislative and rule-making initiatives.

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1 From 1994 to 2004, I worked in environmental consulting and environmental  
2 engineering. I managed a wide variety of projects for various industries focusing  
3 on remediation project management, solid waste compliance, coal ash  
4 management, National Pollutant Discharge Elimination System (NPDES) permit  
5 management and obtaining and managing State and Federal permits. I also  
6 performed complex multi-site due diligence and liability management. I worked  
7 for a variety of industries including utility, cement production, and landfill industry  
8 sectors.

9

10 **Q5. What are your current duties and responsibilities?**

11 A5. I have worked for DTE Energy for 20 years. I am currently the Manager of  
12 Environmental Strategy, and my focus is on complex and strategic environmental  
13 initiatives that are critical to DTE. In this role I focus on environmental strategy,  
14 policy, and regulatory development and am responsible for key environmental  
15 programs at the State and Federal level that are critical to the Company's  
16 compliance, strategic direction, and generation strategy. I am responsible for the  
17 Company's strategy and approach for compliance with the CCR and ELG  
18 programs, waste program, and renewable energy development, contaminated site  
19 remediation, and environmental due diligence.

20

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

23 A6. Yes. I have sponsored testimony in the following cases:

24 U-16999 2012 DTE Gas General Rate Case

25 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 |
| 5 | U-21534 | 2024 DTE Electric General Rate Case |

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1 **Purpose of Testimony**

2 **Q7. What is the purpose of your testimony?**

3 A7. I will describe the status of two significant Environmental Protection Agency  
4 (EPA) regulations, the Steam Electric Power Generating Effluent Limitation  
5 Guidelines (ELG) Rule and the Coal Combustion Residuals (CCR) Rule. These  
6 rules affect the Company's current and former coal-fired power plants. I will  
7 address the following additional topics in my testimony:

8 1) I will explain the ELG Rule, recent revisions, and compliance strategies in  
9 support of Witness Guillaumin's discussion of ELG-related capital  
10 expenditures.

11 2) I will describe how the EPA's CCR Rule affects coal ash management at the  
12 Company's coal-fired units in support of Witness Guillaumin's discussion of  
13 CCR-related capital expenditures.

14

15 **Q8. Are you sponsoring any exhibits in this proceeding?**

16 A8. No.

17

18 **Q9. Is the Company requesting recovery of capital expenditures associated with**  
19 **compliance with EPA regulations?**

20 A9. Yes. As shown in Company Witness Guillaumin's Exhibit A-12, Schedule B5.1,  
21 the Company is in the process of developing and implementing several ELG and  
22 CCR compliance projects necessitating capital expenditures, including:

- 23 • Monroe Dry Fly Ash Conversion (ELG)
- 24 • Monroe Bottom Ash Conversion (ELG)
- 25 • Monroe FGD Wastewater (ELG)

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- 1 • Sibley Quarry Landfill Modification (CCR)
- 2 • Sibley Quarry Infrastructure Modification (CCR)
- 3 • Sibley Quarry Landfill Dewatering and Discharging Line (CCR)
- 4 • Monroe Bottom Ash Basin Closure (CCR)
- 5 • St. Clair Bottom Ash Basin Closure (CCR)
- 6 • Belle River Bottom Ash Basin Modification (CCR)
- 7 • Monroe Fly Ash Basin Closure (CCR)
- 8 • Legacy CCR Evaluation and Monitoring (CCR)

9

10 **Effluent Limit Guidelines**

11 **Q10. What are Effluent Limit Guidelines (ELGs)?**

12 A10. Effluent Limit Guidelines are national wastewater discharge standards developed  
13 by the EPA on an industry-by-industry basis. These technology-based regulations  
14 and are intended to represent the greatest pollutant reductions that are economically  
15 achievable for an industry. The EPA first promulgated the Steam Electric Power  
16 Generating (SEPG) ELGs in 1974, and subsequently amended the regulations in  
17 1977, 1978, 1980, 1982, 2015, 2020 and 2024. The regulations govern wastewater  
18 discharges from steam electric power plants operated by utilities. The Steam  
19 Electric ELGs are incorporated into National Pollutant Discharge Elimination  
20 System (NPDES) permits issued by the Michigan Department of Environment,  
21 Great Lakes & Energy (EGLE).

22

23 **Q11. Can you describe the recent revisions to EPA's SEPG ELGs?**

24 A11. Yes. The EPA's SEPG ELGs regulate how electric utilities must manage certain  
25 wastewaters. On October 13, 2020, the EPA finalized the 2020 ELG

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1 Reconsideration Rule (herein referred to as Reconsideration Rule) which revised  
2 some requirements from the 2015 version of the ELG rule. The Reconsideration  
3 Rule revised requirements for two specific waste streams produced by steam  
4 electric power plants: flue gas desulfurization (FGD) wastewater and bottom ash  
5 transport water (BATW). The Reconsideration Rule provides additional  
6 compliance opportunities by finalizing subcategories, such as for the cessation of  
7 coal burning activities. Therefore, steam electric plants can comply with ELG  
8 requirements for FGD and BATW by either meeting discharge requirements or  
9 those of a subcategory. On March 29, 2023, EPA published a direct final rule (DFR)  
10 to update the Reconsideration Rule by extending the date for existing coal-fired  
11 power plants to submit a notice of planned participation for the permanent cessation  
12 of coal combustion subcategory from October 13, 2021, to June 27, 2023.

13  
14 Recently, the EPA completed a supplemental rulemaking to address discharge  
15 limits in the SEPG ELGs following a science-based review of the Reconsideration  
16 Rule under Executive Order 13990. The EPA finalized the Supplemental ELG Rule  
17 (herein referred to as the Supplemental Rule) on May 9, 2024, subsequently  
18 updating the regulations from the Reconsideration Rule for FGD wastewater,  
19 BATW, Combustion Residual Leachate (CRL), and Legacy Wastewater  
20 (LWW). The Supplemental Rule established new technology-based effluent  
21 limitations guidelines and standards applicable to FGD wastewater, BATW, CRL,  
22 and LWW.

23  
24 The Supplemental Rule supports the Company's ongoing compliance path for  
25 BATW and FGD compliance at Monroe Power Plant and affirms that installation



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of BATW projects, by the end of 2025, and FGD wastewater projects, by the end of 2028, are needed for Units 1 and 2. While the Supplemental Rule does not change the projects that are currently required and necessary; the Company is evaluating effects on future compliance projects.

**Q12. When must DTE Electric comply with the 2020 Reconsideration Rule, 2023 DFR, and 2024 Supplemental Rule?**

A12. The Reconsideration Rule provided 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 rule revisions. The EPA set the applicability dates for BATW and FGD wastewater retrofits in the Reconsideration Rule to be "as soon as possible" beginning October 13, 2021, and no later than December 31, 2025. The Supplemental Rule revised applicability dates for BATW and FGD to be "as soon as possible" beginning July 8, 2024, and no later than December 31, 2029. However, for facilities pursuing the FGD wastewater Voluntary Incentives Program (VIP), detailed further below, compliance shall be achieved no later than December 31, 2028. For facilities pursuing the cessation of coal burning activities compliance subcategory from the Reconsideration Rule, 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 NPDES permits by EGLE.

For Monroe Power Plant, the NPDES permit contains compliance deadlines of December 31, 2023 for fly ash transport water (FATW), December 31, 2025 for

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1 BATW and December 31, 2028, for FGD. For Belle River Power Plant, the  
2 NPDES permit contains a compliance deadline of December 31, 2028 for BATW.

3

4 **Q13. If the Supplemental Rule revised and extended applicability dates for best**  
5 **available technology-based compliance for FGD and BATW, is DTE Electric**  
6 **changing its current compliance deadlines?**

7 A13. No. DTE Electric is only pursuing the best available technology compliance option  
8 for BATW at Monroe Units 1 and 2. During development of the Supplemental Rule  
9 by EPA, the Company remained subject to the requirements of the Reconsideration  
10 Rule as EPA required permitting authorities to continue to implement these  
11 requirements while the EPA undertook the rulemaking process to revise the  
12 Reconsideration Rule. The current BATW compliance deadline for Units 1 and 2  
13 in Monroe's NPDES permit is December 31, 2025. The Company had already made  
14 strategic and financial decisions regarding implementation for the project in order  
15 to meet the December 31, 2025 deadline in the NPDES permit prior to the  
16 Supplemental Rule being finalized. Therefore, DTE Electric will meet a December  
17 31, 2025 compliance date. For FGD compliance at Monroe Units 1 and 2, the  
18 Supplemental Rule did not change VIP compliance requirements, see Q18 for more  
19 details. See Company Witness Guillaumin's testimony at Q43 and Q44 for more  
20 information on the projects.

21

22 **Q14. What is DTE Electric's plan to comply with the Reconsideration Rule and**  
23 **Supplemental Rule?**

24 A14. The Company has two options to achieve compliance under the Reconsideration  
25 Rule and Supplemental Rule for BATW and FGD wastewater. The first option is

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1 to design and engineer new technologies that comply with the ELG requirements  
2 for BATW and FGD wastewater. The second option is to pursue a compliance  
3 subcategory for BATW and FGD wastewater that EPA established within the  
4 Reconsideration Rule. The compliance subcategories established in 2020 for the  
5 Reconsideration Rule were maintained and not impacted by the Supplemental Rule.

6

7 **Q15. What compliance subcategories established within the Reconsideration Rule**  
8 **and maintained by the Supplemental Rule is the Company pursuing?**

9 A15. One subcategory allows companies to attain compliance with the ELGs for both  
10 BATW and FGD wastewater by ceasing coal burning activities, which includes  
11 retiring coal-fired unit(s) or converting unit(s) to other fuels. If companies certify  
12 that unit(s) will cease the use of coal, they can continue to operate those units until  
13 the specified coal retirement date, which is required to be no later than December  
14 31, 2028. For the electrical generating unit(s) that certify under this subcategory,  
15 companies need to maintain the existing standard limits already in effect for BATW  
16 and FGD wastewater discharges until the day of unit shut down.

17

18 In addition to the cessation of coal burning activities subcategory, the  
19 Reconsideration Rule also provides a second subcategory specific to FGD  
20 wastewater. The Reconsideration Rule established Best Available Technology  
21 (BAT) standard discharge limits for FGD wastewater discharges, and further,  
22 finalized a subcategory called the Voluntary Incentive Program (VIP). Under the  
23 VIP, companies could choose to meet more stringent effluent limits established by  
24 EPA. If a company chooses the VIP option, then the applicability date for FGD  
25 wastewater compliance will be no later than December 31, 2028. The Supplemental

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1 Rule maintained, and did not change, the compliance subcategories for ceasing coal  
2 burning activities and VIP from the Reconsideration Rule.

3

4 **Q16. How does a company pursue compliance under a compliance subcategory**  
5 **from the ELG Rule(s)?**

6 A16. To establish compliance for either of these subcategories, companies were required  
7 to submit a Notice of Planned Participation (NOPP) to EGLE before specified  
8 deadlines established in the 2020 Reconsideration Rule and 2023 DFR. Once  
9 submitted, companies are required to submit annual progress reports to EGLE to  
10 ensure the commitment of compliance under the subcategories.

11

12 **Q17. Did the Company submit an NOPP filing for ELG compliance subcategories?**

13 A17. Yes, three NOPPs have been submitted. A cessation of coal NOPP was submitted  
14 for Belle River Power Plant on October 13, 2021. A VIP NOPP was submitted for  
15 Monroe Power Plant Units 1 and 2 on October 13, 2021. Lastly, a cessation of coal  
16 NOPP was submitted for Units 3 and 4 at Monroe Power Plant on April 27, 2023.

17

18 **Q18. Why did DTE Electric submit the VIP NOPP for FGD ELG compliance?**

19 A18. For FGD compliance the Company evaluated a suite of technology options that  
20 would achieve both BAT and VIP compliance requirements for ELG FGD  
21 compliance. At the time of NOPP development, the Company was still evaluating  
22 the suite of potential compliant technologies. To ensure the Company could  
23 continue to evaluate all available technologies, including those that achieved VIP  
24 compliance, the decision was made to submit the VIP NOPP. By submitting the

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1 VIP NOPP, it allowed the Company to continue evaluating all technologies  
2 available on the market and not just technologies capable of achieving BAT.

3

4 In 2022, the Company identified a set of FGD compliance technologies that met  
5 the VIP compliance requirements and committed the Company to the VIP NOPP.  
6 Consistent with the Order in the Company's 2022 Integrated Resource Plan (IRP)  
7 filing, Case No. U-21193, Monroe Units 1 and 2 will continue to operate until 2032,  
8 and FGD compliance will be achieved by December 31, 2028, for those two units  
9 by meeting VIP requirements; see Company Witness Guillaumin's testimony at  
10 Q44. As detailed above, Monroe Units 3 and 4 will achieve compliance via  
11 cessation of coal as indicated by the Company's April 27, 2023 NOPP submittal.  
12 With the submittal of the VIP NOPP, DTE Electric can no longer pursue BAT  
13 compliant technology options.

14

15 **Q19. What is DTE Electric's compliance strategy for Belle River Power Plant?**

16 A19. At Belle River Power Plant, fly ash is collected dry and therefore there is no Fly  
17 Ash Transport Water (FATW). Additionally, the power plant was constructed and  
18 operates without FGDs. Therefore, there is no FGD wastewater. Bottom ash is  
19 collected using transport water and the Reconsideration and Supplemental Rules  
20 require the Company to achieve compliance with BATW discharge requirements.  
21 DTE Electric submitted a NOPP on October 13, 2021 for the cessation of coal at  
22 Belle River Power Plant. Please see Company Witness Guillaumin's testimony  
23 regarding the Company's commitment to convert from coal-fired to natural gas-  
24 fired operations by the end of 2026.

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1   **Q20.   What is DTE Electric’s compliance strategy for Monroe Power Plant?**

2   A20.   At Monroe Power Plant, the Company completed projects for FATW ELG  
3           compliance according to the 2015 ELG Rule and ceased water discharges related  
4           to the transport of fly ash. For BATW wastewater, the Company must achieve  
5           compliance by the end of 2025 as detailed in Q&A13 and will terminate the use of  
6           water for bottom ash transport at Monroe Units 1 and 2. For Units 3 and 4 at  
7           Monroe, the Company submitted a cessation of coal compliance subcategory NOPP  
8           on April 27, 2023. For FGD wastewater, the Company is pursuing VIP compliance  
9           for Units 1 and 2 and cessation of coal NOPP for Units 3 and 4. The Company will  
10          install a VIP compliant option for Monroe Units 1 and 2 no later than December  
11          31, 2028. Monroe Units 3 and 4 will retire in 2028 according to the Company’s  
12          2022 IRP, therefore a cessation of coal NOPP was submitted providing compliance  
13          with the FGD wastewater requirements as retirement will eliminate FGD  
14          wastewater from these units.

15

16   **Q21.   Can the Company avoid capital expenditure for bottom ash compliance on the**  
17           **two units proposed to retire in 2028 at Monroe Power Plant?**

18   A21.   Yes. Compliance for bottom ash ELG requirements must be met no later than  
19          December 31, 2025 in accordance with Monroe Power Plant’s NPDES permit.  
20          However, the EPA finalized the DFR on May 30, 2023, that reopened and extended  
21          the timeframe within the Reconsideration Rule that NOPPs for the cessation of coal  
22          compliance subcategory could be submitted. The Company utilized the opportunity  
23          presented in the DFR and submitted a cessation of coal NOPP for Monroe Units 3  
24          and 4, which are committed to retire in 2028. Consistent with the Order in the  
25          Company’s 2022 IRP, Case No. U-21193, Monroe Power Plant Units 1 and 2 will

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1 continue to operate until 2032 and so a bottom ash compliance project will still be  
2 implemented for ELG compliance.

3

4 **Q22. Does EPA's Supplemental Rule affect or alter planned capital projects to**  
5 **comply with ELG requirements?**

6 A22. No. The Supplemental Rule did not change the need for the BATW and FGD capital  
7 projects for Monroe Units 1 and 2. Both projects rely on technology options that  
8 will result in no discharge of BATW or FGD wastewater. Zero liquid discharge  
9 technologies will always be compliant with ELG requirements as there is no  
10 discharge to regulate.

11

12 **Q23. Does EPA's Supplemental Rule impose new requirements on the Company**  
13 **beyond the compliance projects identified above?**

14 A23. Yes. The Company is currently evaluating the compliance obligations that could  
15 affect certain LWW and CRL at our SEPG sites and licensed CCR landfills.  
16 Potential outcomes of the Supplemental Rule could include new or updated leachate  
17 treatment systems at the Company's CCR landfills.

18

19 **Coal Combustion Residuals**

20 **Q24. What is the Coal Combustion Residuals (CCR) Rule?**

21 A24. The EPA's CCR Rule regulates how electric utilities must manage and dispose of  
22 coal combustion residuals in landfills and impoundments. The CCR Rule was  
23 initially promulgated in 2015 with various amendments that have supported  
24 implementation of State programs, and forced closure of certain impoundments that  
25 were considered unlined. The most recent amendments, included in the Final 2024

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1 Legacy CCR Rule, broadly expanded the regulations governing CCR disposal to  
2 include previously unregulated CCR that exists at certain facilities. Specifically,  
3 the EPA established regulatory requirements for two new classes of CCR units;  
4 legacy CCR surface impoundments which are inactive CCR surface impoundments  
5 at inactive utilities, and any other non-containerized accumulation of CCR known  
6 as CCR Management Units (CCRMU) at certain facilities. Compliance activities  
7 associated with the Final 2024 Legacy CCR Rule are discussed further in question  
8 32 of my testimony.

9

10 **Q25. Can you describe how the EPA's 2020 amendments to the CCR Rule affect the**  
11 **Company locations with coal-fired units?**

12 A25. Yes. On August 28, 2020, the EPA published an amendment to the CCR Rule (the  
13 Part A Rule) that required all unlined surface impoundments to cease receipt of  
14 waste and initiate closure as soon as technically feasible but by no later than April  
15 11, 2021. The August 28, 2020, amendment also provided utilities the ability to  
16 request site-specific alternative closure deadlines through a demonstration process  
17 requiring EPA approval. On November 12, 2020, EPA published an additional  
18 amendment to the CCR rule (the Part B Rule) that allowed utilities the opportunity  
19 to demonstrate that their unlined surface impoundments have an alternate liner  
20 system that is as protective as a CCR rule compliant liner system. The  
21 demonstration processes included in the Part A Rule and Part B Rule required EPA  
22 approval to continue operating CCR surface impoundments.

23

24 **Q26. Can you describe the Company's strategy for each CCR unit to comply with**  
25 **the "Part A" amended closure provisions of the CCR Rule?**



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1     A26.   Yes. The Company submitted a Part A Rule Demonstration for the St. Clair Bottom  
2           Ash Basins on November 25, 2020, in accordance with 40 C.F.R. §257.103(f)(2).  
3           The Demonstration requested an alternative closure deadline based on cessation of  
4           coal fired generation in spring of 2022, and a commitment to complete closure of  
5           the unit by October 17, 2023. Submission of the Part A Rule Demonstration paused  
6           the April 11, 2021 deadline for the unit to cease receipt of waste. On January 11,  
7           2022, the Company received written notice that the Part A Rule Demonstration was  
8           administratively complete and confirmed that the cease receipt of waste deadline  
9           had been paused until EPA issues a final decision on the Demonstration. The  
10          Company ceased operation of the coal-fired boilers at St. Clair Power Plant on May  
11          31, 2022, completed washdowns of CCR containing equipment on August 12,  
12          2022, and commenced physical isolation of the St. Clair Bottom Ash Basins from  
13          power plant infrastructure on September 1, 2022. These actions demonstrated that  
14          the Company had permanently ceased receipt of CCR and non-CCR waste streams  
15          at the St. Clair Bottom Ash Basins and had initiated closure by removal pursuant to  
16          40 C.F.R. §257.102(c). Since the Company ceased receipt of all waste streams to  
17          the St. Clair Bottom Ash Basins prior to any determination by the EPA, the Part A  
18          Demonstration was withdrawn. As discussed further in Company Witness  
19          Guillaumin's testimony at question 50, the Company subsequently completed  
20          dewatering and CCR removal activities in February 2023. The St. Clair Bottom  
21          Ash Basins were backfilled concurrent with and following CCR removal, and  
22          topsoil, seed and mulch placement were complete by May 2023.  
23  
24          On September 13, 2023, EPA acknowledged withdrawal of the Part A  
25          demonstration, stating that EPA reviewed the Demonstration and determined that

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1 it included the required information, analyses and documentation specified under  
2 40 C.F.R § 257.103(f)(2), and consequently determined on January 11, 2022, that  
3 the Demonstration was complete. Accordingly, EPA updated the Part A webpage<sup>1</sup>  
4 to reflect that the Bottom Ash Basins no longer receive waste and that DTE Electric  
5 has withdrawn its Demonstration.

6  
7 Following closure by removal activities, two rounds of samples were collected from  
8 the St. Clair Bottom Ash Basins groundwater monitoring well network.  
9 Groundwater constituent concentrations fall below groundwater protection  
10 standards as documented in the Company's Annual Groundwater Monitoring and  
11 Corrective Action Report (January 2024). Therefore, the Company completed a  
12 notification of closure in accordance with C.F.R. § 257.102(h).

13  
14 **Q27. Can you describe the Company's strategy for each CCR unit to comply with**  
15 **the "Part B" alternate liner provisions of the CCR Rule?**

16 A27. Yes. The Company submitted Part B applications to EPA on November 30, 2020,  
17 to perform Alternate Liner Demonstrations for Belle River Bottom Ash Basins,  
18 Belle River Diversion Basin, and Monroe Fly Ash Basin. The Company received  
19 notice of the EPA's proposed denial on January 25, 2023. The Company is  
20 continuing with projects at each facility to comply with the CCR rules and support  
21 operating the plants. The proposed denials affect each facility as follows:

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<sup>1</sup> 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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1 Belle River Bottom Ash Basins and Diversion Basin:

2 As discussed further in question 41 of Company Witness Guillaumin's testimony,  
3 the Company executed a project to retrofit the Bottom Ash Basins with a CCR-  
4 compliant liner system and close the Diversion Basin by removal. The project was  
5 completed in 2023 in accordance with regulatory timelines. On September 21,  
6 2023, the Company withdrew the Part B application since it had already ceased  
7 receipt of waste in any unlined portion of the units.

8

9 On October 30, 2023, the EPA acknowledged withdrawal of the Part B application,  
10 stating that the EPA reviewed the application and determined that it included the  
11 required information, analyses and documentation specified under 40 C.F.R. §  
12 257.71(d)(1). Consequently, on January 11, 2022, the EPA determined that the  
13 application for the Bottom Ash Basins and the Diversion Basin was complete.

14

15 Following closure by removal activities for the Diversion Basin, two rounds of  
16 samples were collected from the groundwater monitoring well network to certify  
17 that closure by removal is complete. The final notification of completion of closure  
18 was certified on August 29, 2024. The Company is currently discussing acceptance  
19 of the closure with EGLE.

20

21 Monroe Fly Ash Basin:

22 The Company was already in process of developing alternative capacity at Monroe  
23 by converting the existing wet fly ash handling system to a dry system in  
24 accordance with the 2015 ELG rule. The dry fly ash conversion is complete, and  
25 the Fly Ash Basin received its last known shipment of waste on December 29, 2023.

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1 As discussed in the Notification of Intent to Close, the Company has initiated  
2 closure within the appropriate regulatory timeframes. Therefore, on January 25,  
3 2024, the Company withdrew the Monroe Fly Ash Basin Part B Application.

4  
5 The Company is closing the Monroe Fly Ash Basin in place and with an alternative  
6 cover system designed to meet both state and federal requirements. Closure  
7 activities will require drainage (unwatering of free water and dewatering of  
8 separable pore water) to stabilize the existing CCR material, grading of the CCR  
9 material to drain, and installation of the final cover system over the CCR material  
10 to minimize erosion and infiltration. Unwatering and dewatering activities will be  
11 performed throughout construction, as necessary, to manage water within the Fly  
12 Ash Basin. Closure activities, including closure design, permitting, contracting,  
13 and studies are underway. Closure construction is anticipated to be completed in  
14 phases and take a minimum of five years.

15

16 **Q28. Can you describe the Company's strategy for closure of Monroe Bottom Ash**  
17 **Basin?**

18 A28. Yes. The Company ceased receipt of CCR at the Monroe Bottom Ash Basin prior  
19 to the effective date of the 2015 CCR rule. Consequently, the Company prepared  
20 and placed in the facility's operating record a notice of intent to initiate closure on  
21 December 11, 2015, in accordance with §257.100. The Monroe Bottom Ash Basin  
22 was therefore considered an inactive CCR surface impoundment. Section 257.100  
23 was later remanded and revised by EPA, subjecting inactive CCR surface  
24 impoundments to all the requirements applicable to existing CCR surface  
25 impoundments but on an alternative timeframe. In April 2020, it was determined

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1 that the Monroe Bottom Ash Basin did not meet the requirements of §257.60  
2 (placement above the uppermost aquifer) and was subject to closure under the  
3 requirements of §257.101(b)(1)(i). Therefore, it had to cease receipt of both CCR  
4 and non-CCR waste streams as soon as technically feasible, but no later than April  
5 11, 2021, and close in accordance with §257.102. The Company ceased receipt of  
6 non-CCR waste streams and initiated closure on October 21, 2020. As further  
7 discussed in question 47 of Company Witness Guillaumin's testimony, the  
8 Company completed removal of all CCR in October 2024, and is working to  
9 compile the certification report.

10  
11 Following closure by removal construction activities, two rounds of samples will  
12 be collected from the groundwater monitoring well network to ensure that  
13 groundwater constituent concentrations fall below groundwater protection  
14 standards. Upon making that demonstration, the Company estimates preparing the  
15 notification of completion of closure in the second half of 2025.

16  
17 **Q29. Please explain why the site improvements at Sibley Quarry Landfill are**  
18 **necessary and needed to support CCR compliance.**

19 A29. Improvements to infrastructure at Sibley Quarry Landfill have been made to  
20 enhance the storage capability to accept the CCR material from the Monroe Bottom  
21 Ash Basin and Monroe Power Plant production CCR. These improvement projects  
22 were necessary because the Monroe Fly Ash Basin could not accept CCR beyond  
23 2023. Sibley Quarry Landfill has ample permitted capacity and was therefore  
24 selected as the disposal location for the CCR material removed from the Monroe  
25 Bottom Ash Basin and Monroe production CCR. Question 46 of Company Witness

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1           Guillaumin's direct testimony details the costs associated with these improvement  
2           projects.

3

4   **Q30. Please explain why the Monroe Fly Ash Basin Closure project is necessary and**  
5   **what are the required closure time frames.**

6   A30. The Monroe Fly Ash Basin is an existing unlined CCR surface impoundment as  
7       determined under 40 C.F.R. §257.71(a). Therefore, it is subject to the requirements  
8       of 40 C.F.R. §257.101(a)(1), which states that the unit must cease receipt of waste  
9       and initiate closure as soon as technically feasible, but by no later than April 11,  
10      2021. As discussed in the response to Question 27 above, the Company submitted  
11      a Part B Alternate Liner Demonstration Application for the Monroe Fly Ash Basin  
12      on November 30, 2020, in accordance with 40 C.F.R. §257.71(d)(1). On January  
13      11, 2022, the EPA notified the Company that the application was administratively  
14      complete, and that the EPA will pause the facility's deadline to cease receipt of  
15      waste until issuance of a final decision under 40 C.F.R. §257.71(d)(2)(iii)(C). The  
16      Monroe Fly Ash Basin received the known final receipt of waste on December 29,  
17      2023, and initiated closure within 30 days to comply with 40 C.F.R. §257.102(e)(1).  
18      The Company has ceased receipt of waste and initiated closure. Question 48 of  
19      Company Witness Guillaumin's testimony further discusses the details of the  
20      closure project.

21

22           To comply with the closure timeframes of 40 C.F.R. §257.102(f)(1), the Company  
23           must complete closure within five years of commencing closure activities. If  
24           needed, 40 C.F.R. §257.102(f)(2) provides an opportunity for up to five 2-year  
25           extensions, provided the owner or operator can demonstrate the factual

Line  
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1 circumstances which prevented completion of closure within the baseline five  
2 years.

3

4 **Q31. Can you describe how EPA’s Final 2024 Legacy CCR Rule could affect or alter**  
5 **planned capital projects to comply with the previously promulgated CCR**  
6 **rule?**

7 A31. Yes. On May 8, 2024, the EPA published a final rule titled “Hazardous and Solid  
8 Waste Management System: Disposal of Coal Combustion Residuals from Electric  
9 Utilities; Legacy CCR Surface Impoundments.” The final rule established  
10 regulatory requirements for inactive surface impoundments at inactive facilities,  
11 including groundwater monitoring, corrective action, closure, and post closure care  
12 requirements for all CCRMU at regulated CCR facilities. Importantly, the rule  
13 applies to previously unregulated CCR. The 2024 Legacy CCR Rule does not  
14 affect the planned capital projects being implemented to comply with the pre-  
15 existing CCR Rule.

16

17 **Q32. Can you describe how EPA’s Final 2024 Legacy CCR Rule affects current and**  
18 **future capital projects?**

19 A32. Yes. As mentioned above, the new Legacy CCR Rule imposes new requirements  
20 on CCR units that were previously not regulated by the pre-existing CCR rule.  
21 Specifically, the 2024 rule establishes two new classes of regulated CCR units  
22 under the federal CCR rules: legacy CCR surface impoundments and CCRMU.  
23 The Company does not own any legacy CCR surface impoundments and therefore  
24 the impact of the rule to the Company is focused on CCRMU, i.e., any area of land  
25 on which any non-containerized accumulation of CCR is received, is placed, or is

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1 otherwise managed, that is not a regulated CCR unit. The rule requires  
2 owners/operators of all active facilities to undertake a site assessment to identify  
3 any CCRMUs containing one ton or more of CCR. Any CCRMUs that contain  
4 CCR in amounts equal to or greater than 1,000 tons are subject to the CCR rule's  
5 groundwater monitoring, corrective action, closure, and post-closure care  
6 requirements. Any CCRMUs that fall below 1,000 tons would not be subject to the  
7 requirements of the CCR rule but will instead be subject to future permitting to  
8 determine whether additional actions are needed. Question 49 of Company Witness  
9 Guillaumin's testimony describes how the Company is currently evaluating  
10 magnitude of CCRMU at Sibley Quarry Landfill and Belle River, St. Clair, Delray,  
11 River Rouge, Trenton Channel, and Monroe Power Plants, to identify and delineate  
12 any CCRMUs that may be present.

13

14 **Q33. Does this complete your direct testimony?**

15 A33. 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-21860

QUALIFICATIONS  
  
AND  
  
DIRECT TESTIMONY  
  
OF  
  
DAVID C. MILO

**DTE ELECTRIC COMPANY**  
**QUALIFICATIONS AND DIRECT TESTIMONY OF DAVID C. MILO**

Line  
No.

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

2    A1.    My name is David C. Milo. My business address is One Energy Plaza, Detroit,  
3           Michigan 48226. I am employed by DTE Electric as a Fuel Resources Specialist in  
4           the Operations and Logistics group within the Fuel Supply department.

6   **Q2.    On whose behalf are you testifying?**

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

9   **Q3.    What is your educational background?**

10   A3.    I have a Bachelor of Arts Degree in Accounting and a Master of Business  
11           Administration Degree, in Finance, both from Michigan State University, East  
12           Lansing, Michigan.

14   **Q4.    Please summarize your professional experience.**

15   A4.    In 2004, I joined DTE Energy in the Property Tax department as a Senior Tax  
16           Advisor. In this capacity, I was responsible for property tax compliance for  
17           Michigan Consolidated Gas Company and various other subsidiaries of DTE  
18           Energy.

20           In 2008, I transferred to the Budget, Forecast and Reporting group as a Principal  
21           Analyst. In this capacity, my responsibility was to assist in the preparation of  
22           corporate budgets and forecasts and to prepare reports for management on various  
23           financial performance measures for DTE Energy.

Line  
No.

1 In 2010, I transferred to the Asset Management group where I prepared reports on  
2 capital asset expenditures for DTE Energy. In November of that same year, I  
3 transferred to the Gross Margin group as the fuel accountant. In this capacity, my  
4 responsibilities were to prepare the accounting for the purchase and expense of all  
5 fuels used in the production of electricity for DTE Electric and preparation of  
6 internal and regulatory reports thereon.

7

8 In 2013, I transferred to the Fuel Supply department of DTE Electric as a Fuel  
9 Resources Specialist in the Planning and Procurement group. My responsibilities  
10 included preparation of the budget and forecasts regarding all fossil fuels (i.e., coal,  
11 natural gas & oil) used by DTE Electric for electric generation, preparing  
12 management reports on DTE Electric's fossil fuels, and assisting in various  
13 accounting activities.

14

15 **Q5. What are your current duties and responsibilities?**

16 A5. In 2016, I moved to the Operations and Logistics group of Fuel Supply where I  
17 currently manage the Company's railcar fleet. I am responsible for the procurement  
18 and maintenance of the Company's railcar fleet. My duties include ensuring an  
19 adequate number of railcars are under the Company's control to meet coal delivery  
20 needs and they are maintained to meet operational, safety and contractual standards.  
21 In that role, I work with Midwest Energy Resources Company (MERC) personnel  
22 and their operations to coordinate coal deliveries and movements of railcars.

Line  
No.

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

3   A6.   Yes. I have sponsored testimony in the following cases:

4           U-17097-R    2013 Power Supply Cost Recovery (PSCR) Reconciliation

5           U-17319       2014 PSCR Plan

6           U-17319-R   2014 PSCR Reconciliation

7           U-17680       2015 PSCR Plan

8           U-18014       2016 DTE Electric Rate Case

9           U-18255       2017 DTE Electric Rate Case

10          U-20162       2018 DTE Electric Rate Case

11          U-20561       2019 DTE Electric Rate Case

12          U-20836       2022 DTE Electric Rate Case

13          U-21297       2023 DTE Electric Rate Case

14          U-21534       2024 DTE Electric Rate Case

Line  
No.

1 **Purpose of Testimony**

2 **Q7. What is the purpose of your testimony?**

3 A7. The purpose of my testimony is to discuss and support the reasonableness and  
4 prudence of DTE Electric Fuel Supply's and MERC's Fuel Handling actual \$7.51  
5 million of O&M expenses for the 12-month adjusted historic period ended  
6 December 31, 2023, and the projected \$6.26 million O&M expenses for the 12-  
7 month projected test period ending December 31, 2026. I also discuss and support  
8 the reasonableness and prudence of Fuel Supply's \$0.62 million, and MERC's  
9 \$0.87 million, of capital expenditures for historical test year ended December 31,  
10 2023, Fuel Supply's projected capital expenditures of \$1.99 million and MERC's  
11 \$0.42 million from January 1, 2024, through the projected bridge period ending  
12 December 31, 2025. I include an explanation for why there are no projected capital  
13 expenditures for the 12-month test period ending December 31, 2026, for Fuel  
14 Supply and MERC. I also address how the Company's transition away from coal  
15 generated electricity, as explained in the Company's Integrated Resource Plan  
16 (IRP) Case No. U-21193, will affect MERC transshipment operations and the  
17 railcar fleet for the Company. Furthermore, I specifically address the planned  
18 retirement of operations at MERC as directed in the December 1, 2023,  
19 Commission Order in Case No. U-21297 (December 1 Order).

20

21 **Q8. Are you sponsoring any exhibits in this proceeding?**

22 A8. Yes. I am sponsoring the following exhibits:

| 23 | <u>Exhibit</u> | <u>Schedule</u> | <u>Description</u>                             |
|----|----------------|-----------------|------------------------------------------------|
| 24 | A-12           | B5.2            | Projected Capital Expenditures – Fuel Supply & |
| 25 |                |                 | Midwest Energy Resources Company (MERC)        |

|   |      |      |                                                |
|---|------|------|------------------------------------------------|
| 1 | A-13 | C5.2 | Projected Operation and Maintenance Expenses – |
| 2 |      |      | Fuel Supply & Midwest Energy Resources Company |
| 3 |      |      | (MERC)                                         |

6     A9.     Yes, they were.

9 A10. My testimony consists of the following three (3) parts:

|    |          |                                                        |
|----|----------|--------------------------------------------------------|
| 12 | Part III | Fuel Supply and MERC Operations & Maintenance Expenses |
|----|----------|--------------------------------------------------------|

15 **Q11. What is the function of the Fuel Supply department of the Company?**

21 **Q12. Can you describe the railcar fleet and its role in supplying fuel to the power**  
22 **plants that rely on coal for the generation of electricity?**

A12. The Company, through its Fuel Supply department, currently controls a fleet of railcars to transport coal from the mines in Wyoming, Montana, Pennsylvania and West Virginia to the Company's power plants. This fleet is critical to delivering the

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1 required large amounts of coal at the lowest reasonable cost. Each car has the  
2 capacity to hold approximately 120 tons of coal. The coal is moved from the mines  
3 to the Company's power plants in a group of 130 connected railcars (using  
4 couplers), commonly referred to as a unit train, and a railcar can travel over a  
5 hundred thousand miles in a single year. This method is standard across the utility  
6 industry and has been used for decades.

7

8 **Q13. How does railcar fleet maintenance affect Company operations?**

9 A13. It is important for ensuring railcar regulatory compliance and meeting the  
10 Company's coal delivery requirements to regularly maintain railcars. The railroad  
11 industry is highly regulated with governing agencies including the Surface  
12 Transportation Board (STB), Federal Railroad Administration (FRA) and  
13 American Association of Railroads (AAR) that ensure a safe system. Accordingly,  
14 the railroads have implemented a rigorous inspection protocol for the railcars  
15 operating on their railroad system. The inspections can result in unilateral removal  
16 of defective railcars from service due to the attendant operating risks, which  
17 requires the Company to replace an equivalent number of railcars to meet its  
18 delivery requirements. The Company's capital program is designed to limit and/or  
19 avoid repairs to structural aspects of the railcar and other components, including  
20 the wheels and bearings, and the costs incurred for such repairs.

21

22 **Q14. What is the planned future of the railcar fleet?**

23 A14. The Company is currently planning for the retirement of the railcar fleet in 2032,  
24 consistent with the planned retirement of the last two remaining coal fired units at  
25 Monroe Power Plant (MNPP) as explained in the Case No. U-21193 IRP case. The

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1 size of the railcar fleet will be reduced as the amount of expected coal deliveries  
2 decrease due to retirement of coal burning electric generation units at the  
3 Company's two remaining plants over the remaining period.

4

5 **Q15. What is MERC?**

6 A15. MERC is a wholly owned subsidiary of DTE Electric, consisting of a coal terminal  
7 which provides coal transportation and transshipment services to DTE Electric and  
8 other third-party customers through its Superior, Wisconsin terminal. MERC  
9 accepts coal deliveries by rail from the western United States and loads those coal  
10 deliveries onto Great Lakes freighters for delivery to the Company's power plants  
11 and industrial customers around the Great Lakes basin.

12

13 **Q16. Why is MERC included in this rate case filing?**

14 A16. As a wholly owned subsidiary of DTE Electric, MERC is fully consolidated into  
15 DTE Electric. The accounting and ratemaking treatment of MERC's revenues and  
16 costs are specified by MPSC Orders in Case No. U-5041<sup>1</sup>, dated September 17,  
17 1976, and Case No. U-5108<sup>2</sup>, dated May 27, 1977.

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<sup>1</sup> <https://adms.apps.lara.state.mi.us/Mpsc/ViewCommissionOrderDocument/16522>, Order MPSC Case No. U-5041, accessed March 19, 2025.

<sup>2</sup> <https://adms.apps.lara.state.mi.us/Mpsc/ViewCommissionOrderDocument/16595>, Order MPSC Case No. U-5108, accessed March 19, 2025.



Line  
No.

1   **Q17. What is MERC's role in coal transportation to the Company's two remaining**  
2       **operating coal-generation power plants?**

3   A17. MERC is critical to the Belle River Power Plant (BRPP) as it is the only source of  
4       low-sulfur western (LSW) coal for the plant. MERC is also used for coal delivery  
5       of LSW coal to the Company's MNPP. BRPP does not have the rail unloading  
6       system capacity capable of supplying its coal consumption requirements and can  
7       only be supplied by lake vessel deliveries. There are no other facilities or options  
8       for delivering the large coal quantities to BRPP, since other U.S. coal terminals  
9       cannot consistently accommodate the required lake vessel sizes. The continued  
10      utilization of MERC is the most economic method of delivering LSW coal to the  
11      BRPP through the period of the plant's planned cessation of coal-fired operation in  
12      2026, as explained in Case No. U-21193. Regarding MNPP, MERC supplies a large  
13      amount of LSW coal to the plant. These deliveries through MERC are utilized to  
14      maintain reliable coal supply to MNPP and are currently the most economical  
15      means to supplement rail deliveries to MNPP.

16

17   **Q18. What is the planned future of MERC?**

18   A18. The planned future of MERC, considering the Commission's Order in Case No. U-  
19      21193 approving a fuel conversion from coal to natural gas at BRPP, is to cease  
20      MERC transshipment operations at the end of June 2026. This timing coincides  
21      with the projected end of coal deliveries to BRPP. Given this planned retirement  
22      date for MERC, any spending will be limited to reasonable, prudent and necessary  
23      costs for maintaining safe and environmentally compliant operations.

Line  
No.

1 **Part II – Fuel Supply and MERC Capital Investments**

2 **Q19. What does the capital program for the railcar fleet entail, what is the spending**  
3 **plan, and why is it important for the Company's customers?**

4 A19. The capital program for the Company's railcar fleet addresses two key structural  
5 components of the railcars; the truck and the draft systems. The truck system is a  
6 chassis or framework-like structure underneath a railroad car to which wheel axles  
7 and connected wheels and bearings are attached. The draft system is an assembly  
8 behind the couplers at each end of the car to manage the compression and tension  
9 forces between the cars of the unit train as it decelerates and accelerates. These  
10 railcar components are subject to significant physical forces, especially when  
11 loaded with 120 tons of coal and incur wear and tear over time and need to be  
12 replaced. The railcar industry recommendation is that the truck and draft assembly  
13 be rebuilt after 1 million miles of operations. The Company's capital program  
14 focuses on those cars with over 1 million miles of operation and allocates one  
15 million dollars per year to replacing components on these railcars. The program  
16 was implemented almost a decade ago and is expected to be completed in 2025.  
17 This program is important to our customers, since it is designed to limit and/or  
18 avoid repairs and related costs to structural aspects of the railcar and other  
19 components, including the wheels and bearings. The program work accomplished  
20 proactively by the Company at private shops also lowers expenditures by avoiding  
21 repairs performed at the costlier shops owned by the railroads after inspection and  
22 unilateral directives from railroad personnel.

Line  
No.

1   **Q20. How does the transition from coal-fired generation at BRPP and MNPP affect**  
2       **the railcar capital investment program?**

3   A20. As mentioned earlier, the capital investment program the Company implemented is  
4       scheduled to be completed at the end of 2025. The Company will use the railcars  
5       through the life of MNPP, therefore it is reasonable and prudent to complete the  
6       capital program. It should be noted the program is focused only on the railcars that  
7       will still be required through the life of MNPP. The Company expects to have no  
8       capital expenditures from 2026 - 2032 for the railcar fleet. However, the Company  
9       will hire an independent inspector to perform a “teardown” of a sample of railcars  
10      during 2025 to examine the components. Any further spending on the program will  
11      be based on the results of this independent assessment of the condition of the  
12      railcars to ensure the fleet is kept in safe operating order. The inspector’s last  
13      assessment in 2023 indicated that the Company’s railcars were well maintained and  
14      should have minimal issues continuing in service through 2032.

15

16   **Q21. Can you explain the nature of MERC's capital expenditures and how declining**  
17       **coal delivery volumes affect the economics?**

18   A21. The MERC capital expenditures are required to ensure safe operation of the coal  
19       terminal that processes rail shipments of LSW coal for lake vessel delivery to DTE  
20       Electric’s power generation plants in southern Michigan. MERC is a large  
21       industrial facility and has unavoidable fixed costs such as rail tracks, conveyor belts  
22       and equipment to move coal. The decline in the amount of coal being transshipped  
23       necessarily results in a higher dollar per ton cost metric compared to higher volume  
24       periods in the past, as unavoidable fixed costs can’t be lowered without risk to safe  
25       and reliable operations. MERC transshipped slightly lower volumes in 2024 as

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1 compared to the amount in 2023, and expects a further decrease in volume during  
2 2025, and just a portion of those amounts in the projected test period ending  
3 December 31, 2026. This decrease will result in lower total cost as discussed  
4 below.

5

6 **Q22. How does the amount of MERC capital expenditures change from the**  
7 **historical year ended December 31, 2023 through the projected test period**  
8 **ending December 31, 2026?**

9 A22. The amount of capital expenditures decreases for MERC from \$0.87 million in  
10 2023 and \$0.31 million in 2024, to only \$0.11 million in 2025 and then to zero for  
11 2026. The diminished amounts are a result of limiting expenditures to only critical  
12 items that could stop operations if not addressed considering the transition from  
13 coal generation addressed in the Case No. U-21193 IRP Order.

14

15 **Q23. What does Exhibit A-12, Schedule B5.2 show and what should be noted?**

16 A23. Exhibit A-12, Schedule B5.2 shows capital expenditures for Fuel Supply and  
17 MERC for the historical test period 2023, as well as forecasted capital expenditures  
18 for the 24-month projected bridge period (January 1, 2024, through December 31,  
19 2025) and the 12-month projected test year ending December 31, 2026. It should  
20 be noted that in Case No. U-21534, the Company proposed that any net assets  
21 remaining at MERC after operations cease, be securitized (along with the Belle  
22 River coal assets). The following explanations provide a description, purpose and  
23 the necessity for the Fuel Supply and MERC capital expenditures.

Line  
No.

1   **Q24. What is the rationale for Fuel Supply and MERC capital expenditures shown**  
2       **on Exhibit A-12, Schedule B5.2?**

3   A24. All the expenditures described in Q25 and Q26, for the period of January 2023  
4       through December 2025 are related to maintaining safety, meeting environmental  
5       requirements, operating reliably, and/or replacing end-of-life equipment. These  
6       expenditures are not avoidable and are reasonable, prudent and necessary for Fuel  
7       Supply railcar availability and MERC's coal transshipment capabilities to both  
8       BRPP and MNPP.

9

10   **Q25. What are the total capital expenditures for Fuel Supply and MERC for the**  
11       **historical test year 2023 included on Exhibit A-12, Schedule B5.2, column (b),**  
12       **lines 3 and 10?**

13   A25. For Fuel Supply, as described earlier, there is a program to rebuild railcar trucks  
14       and draft system components. The railcar capital program extends the trucks and  
15       draft systems useful life consistent with expected operations and mitigates future  
16       potential railcar repair costs. The costs for these railcar truck and draft system  
17       rebUILds during the January 2023 through December 2023 period were \$0.62  
18       million as shown on Exhibit A-12, Schedule B5.2, line 2, column (b). This was  
19       lower than the planned amount of one million dollars due to a shortage of parts to  
20       perform work requested.

21

22       The total MERC expenditures on line 10 of \$0.87 million consists of \$0.14 million  
23       for conveyor belting to replace damaged belting needed to move coal through the  
24       facility from train unloading to vessel loading, \$0.25 million for components of  
25       large mobile equipment needed to move and form coal piles at the facility and other

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1 heavy movements, \$0.10 for roadways and rail tracks, \$0.16 million for electric  
2 transformers needed to operate heavy machinery and dumpers, and \$0.22 million  
3 for various capital projects that are each less than \$100,000.

4

5 **Q26. What are the projected capital expenditures for Fuel Supply and MERC for**  
6 **the 24 months from January 2024 through December 2025 as reflected on**  
7 **Exhibit A-12, Schedule B5.2, column (e)?**

8 A26. As reflected on line 2 of the Exhibit, Fuel Supply continues the project to rebuild  
9 railcar trucks and draft system components on cars to extend the trucks and draft  
10 systems' useful life and operability consistent with expected operations and to  
11 mitigate future potential railcar repair costs. Fuel Supply is projected to spend  
12 almost \$2.00 million on this truck and draft system rebuilding project over the 24-  
13 month period January 2024 through December 2025, with 2025 being the final year.  
14 Even with the slight adjustment in 2023 capital spending compared to one million  
15 dollars approved, the Company expects 2025 to be the final year of the capital  
16 program, based on the prior number of truck and draft systems replaced with past  
17 funding approvals. As mentioned, a teardown of selected cars will be performed  
18 during 2025 to confirm that the completion of the railcar capital program in 2025  
19 is reasonable and prudent.

20

21 MERC's total capital expenditures for January 2024 through December 2025 are  
22 estimated to be \$0.42 million as exhibited on line 10 column (e). MERC capital  
23 spend will focus on unavoidable expenditures related to safety and replacement of  
24 equipment that becomes obsolete or fails and is necessary for continued operations.  
25 There are no plans to spend capital on items that are not critical to continued safe,

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1 environmentally compliant, and reliable operations consistent with MERC's  
2 planned retirement. As detailed on lines 5 through 9 of the Exhibit, the capital  
3 projects at MERC for the 24 months ending December 31, 2025 consist of \$0.02  
4 million for conveyor belting and associated structures to replace end-of-life  
5 equipment, \$0.17 million for large mobile equipment components to replace  
6 engines and transmissions per manufacturers' recommendations, and \$0.23 million  
7 for capital projects that are less than \$100,000 each to address small emergent  
8 required capital projects related to maintaining reliable and safe operations.

9

10 **Q27. What are the projected capital expenditures for Fuel Supply and MERC for**  
11 **the projected test period, January 1, 2026, through December 31, 2026, as**  
12 **reflected on Exhibit A-12, Schedule B5.2, column (f)?**

13 A27. No capital expenditures are estimated for both entities for the projected test period  
14 January 1, 2026, through December 31, 2026. This is consistent with plans to end  
15 MERC operations after June 30, 2026, and the completion of Fuel Supply's capital  
16 program in 2025, as discussed above.

17

18 **Part III – Fuel Supply and MERC Operations and Maintenance Expenses**

19 **Q28. Can you explain what Fuel Supply and MERC operations and maintenance**  
20 **expenditures are comprised of?**

21 A28. Fuel Supply's expenditures are primarily for the planning, procurement, and  
22 contract administration of the fuel commodities including transportation to plants  
23 and the costs to maintain the Company's railcar fleet. The MERC expenditures are  
24 primarily for the operation of the coal terminal that processes rail shipments of

Line  
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1 western coal for lake vessel delivery to DTE Electric's power generation plants in  
2 southern Michigan.

3

4 **Q29. What does Exhibit A-13, Schedule C5.2, show?**

5 A29. Exhibit A-13, Schedule C5.2, shows historical and projected operation and  
6 maintenance (O&M) expenses associated with the DTE Electric Fuel Supply  
7 department, on lines 1 through 7, and MERC Fuel Handling, on lines 8 through 15.

8

9 **Q30. What were Fuel Supply and MERC's adjusted historical O&M expenses for**  
10 **2023 as shown on Exhibit A-13, Schedule C5.2?**

11 A30. Fuel Supply and MERC Fuel Handling adjusted historical O&M expenses for 2023  
12 totaled \$7.51 million as shown in column (f), line 16. This is comprised of \$4.16  
13 million for Fuel Supply in column (f), line 7, and \$3.35 million for MERC Fuel  
14 Handling in column (f), line 15.

15

16 Fuel Supply O&M expenses include \$0.53 million for operation supervision and  
17 engineering, \$0.04 million for miscellaneous steam power expenses, \$0.08 million  
18 for maintenance supervision and engineering, and \$1.02 million for maintenance of  
19 miscellaneous steam plant in column (f), as well as a Fuel Handling Reclass to  
20 O&M of \$2.48 million in column (d), line 3, for the Fuel Supply department's  
21 portion of Fuel Handling O&M expense recorded in Fuel Account 501.

22

23 MERC's Fuel Handling expenses charged to Fuel Account 501 are shown on lines  
24 10 through 14, column (d), which reflect components of fuel handling costs that are  
25 reclassified to other expense categories on DTE Electric's adjusted historical



Line  
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1 financial statements, as explained by Witness Uzenski (see Exhibit A-3, Schedule  
2 C.16, Page 2 of 2). Therefore, an adjustment is made in column (e) to remove these  
3 cost items from O&M. The remaining amount of \$3.35 million in column (f), line  
4 15 is the total MERC Fuel Handling expenses included in O&M.

5

6 **Q31. What are Fuel Supply and MERC's Fuel Handling projected O&M expenses**  
7 **for the projected test period ending December 31, 2026, as shown on Exhibit**  
8 **A-13, Schedule C5.2?**

9 A31. The total projected test period O&M expense for both groups equals \$6.26 million,  
10 comprised of \$4.56 million for DTE Electric's Fuel Supply in column (l), line 7,  
11 and \$1.70 million for MERC's Fuel Handling in column (l), line 15. These amounts  
12 were based on the adjusted historical 2023 O&M expenses adjusted for inflation  
13 and an adjustment described in response to Q32 below. The inflation adjustment  
14 factors of 3.40% for 2024, 3.00% for 2025, and 3.10% for 2026 are supported by  
15 Company Witness Ms. Uzenski.

16

17 **Q32. Were any adjustments made to derive the January 1, 2026, through December**  
18 **31, 2026, projected test period O&M expense?**

19 A32. Yes, there is an almost two-million-dollar reduction of the expected O&M for  
20 MERC Fuel Handling represented in column (j) line 9. This reduction of MERC's  
21 O&M expense is a result of the expected decrease of O&M costs as operations  
22 cease at the end of June 2026. As with capital, the resulting \$1.70 million of MERC  
23 fuel handling O&M represents the minimum expenses required to operate the  
24 facility safely, reliably, and in an environmentally compliant manner, which are  
25 necessary to ensure that critical coal deliveries are made to the Company's power

Line  
No.

1 plants. As Company Witness Uzenski states in Q194, the Company proposes to  
2 defer as a regulatory liability any O&M costs at MERC that continue to be  
3 recovered in rates above the actual amount incurred, until rates are reset in a future  
4 rate case.

5

6 **Q33. What are your thoughts regarding the Company's MERC and Fuel Supply**  
7 **programs and expenditures?**

8 A33. I believe that the Company's MERC and Fuel Supply programs and expenditures  
9 are reasonable and prudent and properly balance the circumstances involved in  
10 DTE Electric's transition from coal-fired generation with the near-term need for  
11 reliable coal deliveries. The Company has reasonably and prudently minimized its  
12 MERC and Fuel Supply expenditures to those necessary to maintain safe, reliable,  
13 and environmentally compliant operations consistent with its future generation  
14 plans.

15

16 **Q34. Does this complete your direct testimony?**

17 A34. 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-21860

QUALIFICATIONS  
  
AND  
  
DIRECT TESTIMONY  
  
OF  
  
SHAWN D. BURGDORF

**DTE ELECTRIC COMPANY**  
**QUALIFICATIONS AND DIRECT TESTIMONY OF SHAWN D. BURGDORF**

Line  
No.

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

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

6

7   **Q2.   On whose behalf are you testifying?**

8   A2.   I am testifying on behalf of DTE Electric.

9

10   **Q3.   What is your educational background?**

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

14

15   **Q4.   What is your work experience?**

16   A4.   After receiving my Bachelor's degree from the University of Michigan in 2005, I  
17       was employed by Consumers Energy Company (Consumers Energy). During my  
18       initial employment at Consumers Energy, I worked in their production cost  
19       modeling group where I supported the development of power supply forecasts using  
20       the PROMOD® model. In 2009, I transferred positions to Transmission and  
21       Regulatory Strategies where I was responsible for monitoring and analyzing filings  
22       by the Midcontinent Independent System Operator (MISO) at the Federal Energy  
23       Regulatory Commission (FERC). I was also responsible for forecasting future  
24       transmission and certain energy market-related costs in Power Supply Cost

Line  
No.

1 Recovery (PSCR) proceedings before the Michigan Public Service Commission  
2 (Commission or MPSC).

3

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

8

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

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

15

16 **Q6. What are your current duties and responsibilities?**

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

Line  
No.

- 1   **Q7.    Have you previously sponsored testimony before the Michigan Public Service**  
2           **Commission (MPSC or Commission)?**
- 3    A7.    Yes. I have sponsored testimony in the following MPSC cases:
- |    |           |                                                           |
|----|-----------|-----------------------------------------------------------|
| 4  | U-16149   | Consumers Energy's 2010-2011 Gas Cost Recovery (GCR) Plan |
| 5  | U-16485   | Consumers Energy's 2011-2012 GCR Plan                     |
| 6  | U-16924   | Consumers Energy's 2012-2013 GCR Plan                     |
| 7  | U-16890   | Consumers Energy's 2012 PSCR Plan                         |
| 8  | U-17097-R | DTE Electric's 2013 PSCR Reconciliation                   |
| 9  | U-17319-R | DTE Electric's 2014 PSCR Reconciliation                   |
| 10 | U-17632   | DTE Electric's 2013 Renewable Energy Plan Reconciliation  |
| 11 | U-17680   | DTE Electric's 2015 PSCR Plan                             |
| 12 | U-17793   | DTE Electric's 2015 Amended Renewable Energy Plan         |
| 13 | U-17804   | DTE Electric's 2014 Renewable Energy Plan Reconciliation  |
| 14 | U-17920   | DTE Electric's 2016 PSCR Plan                             |
| 15 | U-17680-R | DTE Electric's 2015 PSCR Reconciliation                   |
| 16 | U-18111   | DTE Electric's 2016 Amended Renewable Energy Plan         |
| 17 | U-18082   | DTE Electric's 2015 Renewable Energy Plan Reconciliation  |
| 18 | U-18143   | DTE Electric's 2017 PSCR Plan                             |
| 19 | U-17920-R | DTE Electric's 2016 PSCR Reconciliation                   |
| 20 | U-20069   | DTE Electric's 2017 PSCR Reconciliation                   |
| 21 | U-20221   | DTE Electric's 2019 PSCR Plan                             |
| 22 | U-20471   | DTE Electric's 2019 Integrated Resource Plan (IRP)        |
| 23 | U-20561   | DTE Electric's 2019 Main Rate Case                        |
| 24 | U-20528   | DTE Electric's 2020 PSCR Reconciliation                   |
| 25 | U-18091   | DTE Electric's 2021 PURPA Avoided Cost                    |

Line  
No.

|   |         |                                    |
|---|---------|------------------------------------|
| 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 |
| 4 | U-21534 | DTE Electric's 2024 Main Rate Case |

Line  
No.

1 **Purpose of Testimony**

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

3 A8. The purpose of my testimony is to support capacity-related costs that are part of the  
4 Company's power supply costs, establish the projected wholesale market energy  
5 sales revenue, net of fuel, and to discuss future MISO rule changes associated with  
6 Load Modifying Resources (LMRs). My testimony consists of the following two  
7 sections:

8 **Section I:** Calculation of projected capacity-related generation costs that  
9 are part of the Company's power supply costs and projected wholesale  
10 market energy sales revenue, net of fuel, including a reconciliation of costs  
11 in 2024.

12

13 **Section II:** Discussion of the MISO rule changes for LMRs to support  
14 Witness Leuker's testimony on the potential impact to DTE Electric's  
15 current and future LMR programs.

16

17 **Q9. Are you sponsoring any exhibits in this proceeding?**

18 A9. Yes, I am sponsoring the following exhibits:

| 19 | <u>Exhibit</u> | <u>Schedule</u> | <u>Description</u>                            |
|----|----------------|-----------------|-----------------------------------------------|
| 20 | A-26           | P1              | Projected 2026 PURPA Capacity-Related         |
| 21 |                |                 | Generation Cost                               |
| 22 | A-26           | P2              | Projected 2026 PA 295/PA 342 Capacity-Related |
| 23 |                |                 | Generation Cost                               |



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1 A-26 P3 Projected 2026 Capacity-Related Generation Cost &  
2 Energy Sales Revenue, Net of Fuel, Cost Including  
3 2024 Reconciliation

4 A-26 P4 2024 Energy Sales Revenue, Net of Fuel

5  
6 **Q10. Were these exhibits prepared by you or under your direction?**

7 A10. Yes, they were.

8

9 **Section I: Calculation of projected capacity-related generation costs that are part of**  
10 **the Company's power supply costs and projected wholesale market energy sales**  
11 **revenue, net of fuel, including 2024 reconciliation.**

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

16 A11. The Company's PSCR mechanism includes capacity-related generation costs  
17 associated with Public Utility Regulatory Policies Act of 1978 (PURPA) power  
18 purchase agreements (PPAs), PA 295/PA 342 Company-owned renewable energy  
19 systems, PA 295/PA 342 renewable energy contracts, and capacity purchases.

20

21 **Q12. How did the Company project the 2026 capacity-related generation costs for**  
22 **PURPA PPAs included in its PSCR plan filing in Case No. U-21594?**

23 A12. Most of the Company's PURPA contracts have three rate components: fixed,  
24 operation and maintenance (O&M), and variable. Two of the Company's PURPA  
25 contracts only have a capacity component. The projections for the fixed, O&M,

Line  
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1 and capacity components are included in the capacity-related generation costs. The  
2 total projected 2026 PURPA capacity-related generation cost is \$8.1 million as  
3 shown on Exhibit A-26, Schedule P1, line 12, column (e).

4

5 **Q13. What costs associated with PA 295/PA 342 Company-owned renewable energy**  
6 **systems and PPAs are included in the PSCR?**

7 A13. The portion of the cost of PA 295/PA 342 Company-owned renewable energy  
8 systems that is passed through the PSCR Transfer Price mechanism is the approved  
9 Transfer Price Schedule or the levelized cost of energy for the renewable energy  
10 systems. The portion of the cost of PA 295/PA 342 PPAs (i.e., non-Company  
11 owned) that is passed through the PSCR mechanism is the lower of: the Transfer  
12 Price approved for the PPA or the contract price of the agreement.

13

14 The Transfer Price is a proxy for the incremental non-renewable capacity and  
15 energy expense that would be passed to customers if the renewable energy resource  
16 was not developed. The relevant statute explains that when setting the Transfer  
17 Price the Commission shall consider factors including, but not limited to, projected  
18 capacity, energy, maintenance, and operating costs, information filed under Section  
19 6j of 1939 PA 3 (MCL 460.6j), and wholesale market data including, but not limited  
20 to, locational marginal pricing.

21

22 **Q14. How did the Company project the 2026 capacity-related generation costs for**  
23 **PA 295/PA 342 Company-owned renewable energy systems and PPAs?**

24 A14. The capacity-related generation cost for PA 295/PA 342 Company-owned  
25 renewable energy systems and PPAs is the approved Transfer Price fixed

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No.

1 component for each specific renewable energy system. The total projected 2026  
2 PA 295/PA 342 capacity-related generation cost is \$145.8 million as shown on  
3 Exhibit A-26, Schedule P2, line 41, column (i).

4

5 **Q15. How did the Company project the 2026 cost of capacity purchases?**

6 A15. The Company included the net capacity purchase costs based on the 2025 PSCR  
7 Plan (Case No. U-21594) forecasted expense for the calendar year 2026. The  
8 expense includes the Company's net transactions from the MISO annual Planning  
9 Resource Auctions (PRA) covering the 2026 calendar year<sup>1</sup>. Consistent with the  
10 amount filed in Case No. U-21594, the Company is projected to purchase short-  
11 term capacity in the amount of \$7.4 million as shown on Exhibit A-26, Schedule  
12 P3, line 6, column (b).

13

14 **Q16. How did the Company calculate the projected 2026 energy sales revenue net**  
15 **of projected fuel costs per Section 6w(3)(b) of PA 341?**

16 A16. Section 6w(3)(b) of PA 341 requires that the revenue, net of projected fuel costs,  
17 from energy market sales, off-system energy sales, ancillary services sales, and  
18 energy sales under unit-specific bilateral contracts be subtracted from the  
19 Company's capacity costs before calculating its capacity charge. I performed the  
20 calculation using the forecasted assumptions from the Company's 2025 PSCR Plan,  
21 Case No. U-21594. To calculate the energy sales revenue net of projected fuel costs,  
22 first the projected wholesale energy revenue from the Company's generation  
23 resources (including PPAs) was determined (Exhibit A-26, Schedule P3, line 11).

---

<sup>1</sup> MISO annual resource adequacy auctions cover the Planning Year from June 1st – May 31st. The 2025/26 Planning Year auction covers January 1st – May 31st, 2026 and the 2026/27 Planning Year auction covers June 1st – December 31st, 2026.

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No.

1 Next, the projected wholesale revenue associated with ancillary services provided  
2 by the Company's generation resources was determined (Exhibit A-26, Schedule  
3 P3, line 14). Finally, all fuel expenses associated with the wholesale energy and  
4 ancillary services were determined (Exhibit A-26, Schedule P3, line 21) and  
5 subtracted from the projected wholesale revenues (Exhibit A-26, Schedule P3, line  
6 16) resulting in the energy sales revenue net of projected fuel costs (Exhibit A-26,  
7 Schedule P3, line 23).

8

9 **Q17. What is the projected revenue associated with wholesale energy sales from the**  
10 **Company's generation resources in 2026?**

11 A17. The Company receives wholesale energy revenues from the MISO wholesale  
12 energy market for the electricity produced by its generation assets. The wholesale  
13 energy revenues forecasted for all Company assets (including PPAs) in the  
14 Company's 2025 PSCR Plan (U-21594) was calculated as approximately \$2.1  
15 billion shown on Exhibit A-26, Schedule P3, line 11, column (b). This was  
16 accomplished by summing the hourly generation multiplied by the corresponding  
17 hourly market price.

18

19 **Q18. Is the Company projecting any off-system energy sales or sales under unit**  
20 **specific bilateral contracts in 2026?**

21 A18. No, these values are shown as zero on Exhibit A-26, Schedule P3, line 12 and 13.

22

23 **Q19. What is the projected ancillary services revenue from the Company's**  
24 **generation resources in 2026?**

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No.

1 A19. The Company receives wholesale revenue for providing the following ancillary  
2 services: regulation reserves, spinning reserves, supplemental, and short-term  
3 reserves (all settled via MISO's energy and ancillary services market). The  
4 Company's 2025 PSCR Plan projected that Company's generation resources would  
5 generate \$4.4 million of wholesale revenue associated with regulation, spinning,  
6 and supplemental reserves. The projected wholesale ancillary services revenues  
7 from the Company's generation resources in 2026 are shown on Exhibit A-26,  
8 Schedule P3, line 14. Schedule 2 Reactive Ancillary Services Revenue is no longer  
9 included since FERC approved elimination of Schedule 2 compensation in 2023.

10

11 **Q20. What is the total projected wholesale energy sales revenue including ancillary**  
12 **services in 2026?**

13 A20. The total projected wholesale energy sales revenue including ancillary services in  
14 2026 is approximately \$2.1 billion as shown on Exhibit A-26, Schedule P3, line 16,  
15 column (b).

16

17 **Q21. What is the projected fuel cost required to generate the projected wholesale**  
18 **energy and ancillary services sales from the Company's generation resources**  
19 **in 2026?**

20 A21. The projected fuel cost required to make the energy and ancillary services market  
21 sales is projected from the generation in the 2025 PSCR Plan and includes: fuel,  
22 variable component of PPAs, and the variable component of renewables (based on  
23 removing the fixed component of the MPSC-approved Transfer Prices from the  
24 overall Transfer Price). Total projected fuel costs for the Company's generation

Line  
No.

1 fleet are approximately \$1.2 billion as shown on Exhibit A-26, Schedule P3, line  
2 21, column (b).

3

4 **Q22. How did you address the MISO market administrative costs associated with**  
5 **Schedule 17 as well as chemical and emission expenses?**

6 A22. The Schedule 17 costs from the fuel cost amount were removed in accordance with  
7 the Commission Order in Case No. U-20836. However, these costs should be  
8 included in fuel costs under Section 6w(3)(b) of PA 341, as they are directly  
9 attributable to “injections” of energy into MISO and must be incurred to effectuate  
10 the generation sales.

11

12 The chemical and emission costs were also removed, which amount to \$28.1  
13 million, in accordance with the Commission Order in Case No. U-21297, yet this  
14 is misguided. Chemical and emission costs are required to produce the energy from  
15 some of the Company’s generation assets; the revenues associated with the energy  
16 sales would not be possible without these expenses. To provide the “benefit” of the  
17 energy sales to customers being assessed a capacity charge per the State Reliability  
18 Mechanism (SRM) without including all the attributable costs required to produce  
19 the energy associated with the sales is not fair to the Company’s PSCR customers  
20 who ultimately bear the burden for such extra costs, effectively subsidizing  
21 customers assigned the SRM Capacity Charge.

22

23 The SRM originated to ensure all electric suppliers plan for reliable energy  
24 supplies, respectively; and it also allows for electric choice customers to obtain  
25 temporary capacity from the incumbent utility while continuing to receive energy

Line  
No.

1 from their respective alternative electric supplier. This flexibility already allows  
2 electric choice customers to receive the benefit of short-term market trends without  
3 committing to the long-term investments needed for reliability. It should not  
4 inappropriately burden the Company's full-service customers by providing  
5 additional, unwarranted subsidies to electric choice customers.

6

7 **Q23. What was the Company's actual wholesale energy sales revenue net of fuel**  
8 **related costs in 2024?**

9 A23. I calculated the Company's actual wholesale energy sales revenue net of fuel  
10 related costs in 2024; this amount is \$300.0 million, which is shown on Exhibit A-  
11 26, Schedule P4, line 12, column (c). That actual amount was \$1,119.7 million less  
12 than the projected wholesale energy sales revenue net of fuel related costs  
13 embedded in the Company's rate design in effect in 2024.

14

15 **Q24. What is the Company's projected wholesale energy sales revenue, net of**  
16 **projected fuel costs, per Section 6w(3)(b) of PA 341 for 2026 including the**  
17 **reconciliation of 2024?**

18 A24. The total projected 2026 wholesale energy sales revenue of \$2.1 billion, net of \$1.2  
19 billion in fuel costs equates to approximately \$916.6 million wholesale energy sales  
20 revenue, net of fuel, costs as shown on Exhibit A-26, Schedule P3, line 23, column  
21 (b). The reconciliation of the net sales benefit difference for 2024 of (\$1,119.7)  
22 million (Exhibit A-26, Schedule P4, line 12, column (d)) was added to the 2026  
23 projection resulting in an amount of (\$203.2) million (Exhibit A-26, Schedule P3,  
24 line 25, column (b)). This amount was provided to Company Witness Cejas  
25 Goyanes to develop his capacity-related cost of service.

Line  
No.

1 **Section II: Discussion of the future MISO rule changes for LMRs**

2 **Q25. Why is MISO making tariff changes for LMRs?**

3 A25. Historically, LMRs were primarily utilized by utilities and load serving entities that  
4 were overseen by state regulatory agencies. This has changed as more third-party  
5 marketers have registered LMRs with MISO. In addition, the generation  
6 transformation occurring across the industry is placing a focus on ensuring that  
7 resources are reliable. This has created a need for greater visibility on LMRs to  
8 ensure they actually exist and can perform as expected when needed by MISO.  
9 Recently, there have been a number of third-party aggregators, as mentioned by  
10 Company Witness Leuker, that have taken advantage of the less restrictive MISO  
11 tariff rules regarding LMRs to inappropriately benefit while not providing the  
12 reliability benefits expected by MISO. MISO's proposed changes will help  
13 mitigate the potential gaming by third-party aggregators and ensure reliability from  
14 LMRs.

15

16 **Q26. What are the major changes to MISO's rules relating to LMRs?**

17 A26. MISO has filed with FERC on April 4, 2025 tariff changes for LMRs that are  
18 expected to impact DTE Electric's LMR portfolio as further discussed by Witness  
19 Leuker. The major changes include: 1) notification time and associated  
20 deployment, 2) testing requirements, 3) meter data reporting, and 4) number of  
21 interruptions per season.

22 1) MISO is changing "emergency use only" LMRs to be divided into two  
23 types: Type I and Type II. The types are bifurcated by how quickly a  
24 LMR can respond to MISO's notifications, with Type I deploying  
25 within six hours of notification and Type II deploying within 30 minutes



Line  
No.

1 of notification. It is expected that Type I LMRs will be deployed more  
2 frequently as they will be deployed sooner in MISO's maximum  
3 generation emergency steps while Type II LMRs would still be made  
4 available but deployed later in the MISO emergency steps.

5 2) MISO is proposing more stringent testing requirements for both LMR  
6 types. Type I will be required to test upon initial registration and only  
7 again if the amount of megawatts registered changes. Type II LMRs  
8 will be required to test annually. Testing will be done at random by  
9 MISO with limited "opt-out" provisions.

10 3) MISO is proposing to require meter data submission to determine LMR  
11 accreditation amounts. Accreditation will be based on actual availability  
12 during MISO's seasonal capacity advisory hours over the last planning  
13 year.

14 4) MISO is proposing to remove any limits on the number of interruptions  
15 (currently five times in summer and winter seasons and three times in  
16 fall and spring seasons) and to be available whenever an emergency is  
17 declared.

18

19 **Q27. What is the expected timeframe for when these tariff changes will go into**  
20 **effect?**

21 A27. MISO filed the LMR tariff changes with FERC on April 4, 2025. MISO's  
22 requested effective date for all changes is the start of Planning Year 2028 (June 1,  
23 2028) with the testing requirements potentially effective sooner.

Line  
No.

1     **Q28. Does this complete your direct testimony?**

2     A28. Yes.

**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-21860

QUALIFICATIONS  
  
AND  
  
DIRECT TESTIMONY  
  
OF  
  
JEFFREY C. DAVIS

**DTE ELECTRIC COMPANY**  
**QUALIFICATIONS AND DIRECT TESTIMONY OF JEFFREY C. DAVIS**

Line  
No.

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

2   A1.   My name is Jeffrey C. Davis (he/him/his). My business address is: 6400 North  
3       Dixie Highway, Newport, Michigan, 48166. I am employed by DTE Electric  
4       Company at the Fermi 2 Nuclear Power Plant as Expert - Nuclear Strategic  
5       Business Operations.

6

7   **Q2.   On whose behalf are you testifying?**

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

9

10   **Q3.   What is your educational background?**

11   A3.   I graduated from the University of Michigan with bachelor's degrees in nuclear  
12       engineering and radiological sciences (NERS) and engineering physics. I have also  
13       earned a master's degree and doctorate in NERS from the University of Michigan.

14

15   **Q4.   Please summarize your professional experience.**

16   A4.   I have been employed by DTE Energy since 2008. Prior to my current position, I  
17       was Manager – Nuclear Strategy and Business Support with responsibility for  
18       developing the strategic financial plan and goals for the Nuclear Generation  
19       organization. From 2008-2015, I was a principal financial analyst with  
20       responsibility for budgeting, forecasting, and reporting operations and maintenance  
21       (O&M) and capital expenditures for the Nuclear Generation organization.

22

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

25   A5.   I am a member of the American Nuclear Society.

Line  
No.

1   **Q6.   What are your current duties and responsibilities?**

2   A6.   I am responsible for advancing the strategic financial and operational plan and goals  
3           for the Nuclear Generation organization.

4

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

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

8           U-20203       2018 Power Supply Cost Recovery (PSCR) Reconciliation

9           U-20528       2020 PSCR Reconciliation

10          U-20162       2018 DTE Electric Rate Case

11          U-20561       2019 DTE Electric Rate Case

12          U-20836       2022 DTE Electric Rate Case

13          U-21297       2023 DTE Electric Rate Case

14          U-21534       2024 DTE Electric Rate Case

Line  
No.

1 **Purpose of Testimony**

2 **Q8. What is the purpose of your testimony?**

3 A8. The purpose of my testimony is to discuss and support the reasonableness of the  
4 Company's actual nuclear O&M and capital expenditures for the 12-month  
5 historical test period ended December 31, 2023. I will also discuss and support the  
6 reasonableness of the projected nuclear O&M and capital expenditures for the  
7 bridge forecast period and the 12-month projected test period ending December 31,  
8 2026. In addition, I will discuss and support the reasonableness of the projected  
9 Nuclear Surcharge for the projected test period ending December 31, 2026.

10

11 **Q9. Are you sponsoring any exhibits in this proceeding?**

12 A9. Yes. I am sponsoring the following exhibits:

| 13 | Exhibit | Schedule | Description                               |
|----|---------|----------|-------------------------------------------|
| 14 | A-12    | B5.3     | Projected Capital Expenditures - Nuclear  |
| 15 |         |          | Production Plant and Nuclear Fuel         |
| 16 | A-13    | C5.3     | Projected Operation and Maintenance       |
| 17 |         |          | Expenses - Nuclear Power Generation       |
| 18 | A-13    | C5.16    | Nuclear Power Generation - Projected      |
| 19 |         |          | PERC O&M Expenditures                     |
| 20 | A-20    | J1       | Proposed Nuclear Surcharge Projected Test |
| 21 |         |          | Period – 12 Months Ending December 31,    |
| 22 |         |          | 2026                                      |
| 23 | A-20    | J2       | Nuclear Plant Capital Project Detail –    |
| 24 |         |          | Routine and Small Projects                |

Line  
No.

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

2   A10.   Yes, they were.

3

4   **Q11.   How do you plan to proceed with your testimony?**

5   A11.   I will begin my testimony with the Nuclear Generation capital expenditures;  
6           discussing and supporting the actual capital expenditures for the historical test year  
7           ended December 31, 2023, the projected capital expenditures for the bridge forecast  
8           period and the 12-month projected test period ending December 31, 2026. I have  
9           divided my Nuclear Generation capital expenditure discussion into five sections of  
10          expenditures: Routine and Small Projects, Non-Routine and Large Projects,  
11          Nuclear Fuel, Allowance for Funds Used During Construction (AFUDC), and Plant  
12          Activity (removal costs, plant in service and CWIP).

13

14         I will then discuss and support the actual O&M expenses for the historical test year  
15         ended December 31, 2023 and the forecasted O&M expenses for the 12-month  
16         projected test period ending December 31, 2026 for Nuclear Generation. I have  
17         divided the Nuclear Generation O&M expenses discussion into three sections: rate  
18         case adjustments, adjusted historical test period and projected adjustments.

19

20         I will then discuss and support the Nuclear Surcharge for the 12-month projected  
21         test period ending December 31, 2026 for Nuclear Generation.

22

23         The Fermi 2 Power Plant is licensed by the Nuclear Regulatory Commission (NRC)  
24         to operate through 2045. The capital and O&M expenditures discussed for the  
25         historical, bridge, and projected test periods throughout my testimony reflect

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1 appropriate measures to ensure safe and reliable operation of the Fermi 2 Power  
2 Plant through 2045.

3

4 **Nuclear Generation Capital Expenditures**

5 **Q12. Can you provide an outline of your Nuclear Generation capital expenditures**  
6 **discussion?**

7 A12. My testimony will begin with the 2023 – 2026 Capital Projects Overview and then  
8 discuss and support the additional details regarding:

- 9 • Routine and Small Projects  
10 • Non-Routine and Large Projects  
11 • Total Nuclear Fuel  
12 • AFUDC Forecast  
13 • Plant Activity (Removal Costs, Plant in Service and CWIP)

14

15 **2023 - 2026 Capital Projects Overview**

16 **Q13. Can you provide an overview of the Nuclear Generation capital expenditures**  
17 **you support?**

18 A13. I refer you to Exhibit A-12, Schedule B5.3, page 1 which depicts the actual capital  
19 expenditures for the historical test year ended December 31, 2023, projected capital  
20 expenditures for the bridge forecast period and projected capital expenditures for  
21 the 12-month projected test period ending December 31, 2026.

22

23 Total capital expenditures are composed of Routine and Small Projects, Non-  
24 Routine and Large Projects, and Total Nuclear Fuel. Nuclear Generation actual  
25 capital expenditures for historical test year ended December 31, 2023, totaled



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1 \$264.0 million as shown on line 11, column (b) of the exhibit. Nuclear Generation  
2 forecasts total capital expenditures for the projected bridge forecast period at  
3 \$399.6 million as shown on line 11, column (e) and for the 12-month projected test  
4 period ending December 31, 2026, at \$187.4 million as shown on line 11, column  
5 (f).

6

7 I describe and support a portfolio of discrete reasonable and prudent projects and  
8 capital fuel expenditures which provides the basis for the historical actual and  
9 forecasted Total Capital Expenditures for January 1, 2023, through December 31,  
10 2026.

11

12 **Q14. How do the historical actuals for the 12-month period ending December 31,**  
13 **2023, compare to the Nuclear Generation capital (including nuclear fuel)**  
14 **expenditures projected for the same period in the Case No. U-21534 DTE**  
15 **Electric rate case?**

16 A14. The Company's Case No. U-21534 projected Nuclear Generation capital  
17 expenditures were \$266.7 million for the 12-month period ending December 31,  
18 2023. The actual Nuclear Generation capital expenditures for the same period were  
19 \$264.0 million. The total variance is approximately 1.0% of projected total Nuclear  
20 Generation capital expenditures for the referenced period.

21

22 **Q15. What was the Commission's treatment of Nuclear Generation capital**  
23 **expenditures in the Case No. U-21534 Order, dated January 23, 2025?**

24 A15. DTE Electric's Nuclear Generation capital expenditures depicted in Case No. U-  
25 21534 were generally accepted and allowed for recovery with the notable exception

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1 that the Commission did not approve for present recovery projected capital  
2 expenditures through April 2024 in variance to the actual capital expenditures  
3 through April 2024. In addition, the Commission generally did not approve for  
4 present recovery 15 – 20% of projected capital expenditures for the 20-month  
5 projected period ending December 31, 2025, based on an application of Association  
6 for the Advancement of Cost Engineers (AACE) cost estimate classifications for  
7 assigning uncertainties to certain project estimates.

8

9 **Q16. Do you agree with the application of AACE cost estimate classifications with**  
10 **regards to Nuclear Generation capital expenditures?**

11 A16. No. I discuss the rationale for my conclusion that the use of AACE cost estimate  
12 classifications are not representative of the projected-expenditure uncertainty that  
13 may or may not exist in Nuclear Generation's capital expenditure projections  
14 below. Also note, Company Witness Ludlow provides his insights and  
15 recommendations regarding AACE class cost estimate classifications in his direct  
16 testimony.

17

18 **Q17. Can a definitive certainty or range of uncertainty, such as those used by the**  
19 **AACE project cost estimate classifications, be applied to Nuclear Generation**  
20 **projected capital expenditures?**

21 A17. No; however, I consider the projected expenditures a reasonable and prudent  
22 commitment by DTE Electric to operate the Fermi 2 Power Plant safely and reliably  
23 through expending the projected amounts as depicted, in total, and consistent with  
24 Fermi 2's operating priorities. DTE Electric proactively manages its portfolio of  
25 capital projects to deliver outcomes consistent with Fermi 2's operating priorities.

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1 Determination of projected-expenditure uncertainty requires statistical analysis of  
2 a sufficient population of project outcomes with proper application of adjustments  
3 for proactive management decisions, scope changes and timing outcomes that may  
4 impact final project expenditures. The data to perform such a statistical analysis  
5 does not readily exist and thus definitive application of any project cost estimation  
6 classification, AACE or otherwise, is not reasonable. DTE Electric can demonstrate  
7 through historical analysis, however, that projected amounts depicted can be  
8 reasonably expected to be expended in total for projected periods because of DTE  
9 Electric's proactive approach to nuclear project management and its adherence to  
10 DTE Electric's nuclear-safety priority.

11

12 **Q18. Are Nuclear Generation's projected expenditures created using AACE**  
13 **framework?**

14 A18. No. Nuclear Generation projected expenditures use a combination of historical  
15 analysis, technical and supplier feedback, and existing contracts for skilled labor  
16 and regularly executed equipment purchases to provide high confidence that  
17 Nuclear Generation's projected expenditures are reasonable and prudent and  
18 committed to be expended, in total, as depicted in Exhibit A-12, Schedule B5.3. As  
19 an illustrative example: The control rod blade (CRB) replacements project (Exhibit  
20 A-12, Schedule B5.3, page 3, line 10) has projected expenditures based solely on  
21 quantity of CRBs projected to be replaced in the upcoming Refueling Outage 23  
22 (RF23) and the known cost to purchase these CRBs under an existing contract with  
23 the only available manufacturer of CRBs qualified for Fermi 2; the projected  
24 amounts should be considered highly certain and should be considered the lower  
25 bounds of the projected expenditures for this cycle of CRB purchases.

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1 I also note that Nuclear Generation projections depicted in Exhibit A-12, Schedule  
2 B5.3 are fully supported in workbooks and supplemental filings by-month, by-cost  
3 element and by-cost element-by-month using multiple formats and demonstrate the  
4 projected amounts exclude contingencies. If projections were not supported with  
5 reasonable specificity, it would not be possible for these projects to precisely tie  
6 across the supporting documentation.

7

8 **Q19. Has the Commission reviewed DTE Electric's Nuclear Generation historical**  
9 **actuals for the 12-month period ending December 31, 2023, in U-21534?**

10 A19. Yes. When DTE Electric filed Case No. U-21534 in 2024, the projected 12-month  
11 period ending December 31, 2023, included eleven months of actuals and only one  
12 month of forecast. Most expenditures were complete, known and actuals already  
13 included in the expenditures depicted in the Case No. U-21534 Exhibit A-12,  
14 Schedule B5.3; therefore, I will focus on highlighting projects that are more  
15 significant in the bridge and projected test years. Moreover, during the course of  
16 the Case No. U-21534 proceeding, the full 12 months of 2023 actual capital  
17 expenditures as well as the 8-month period ending August 31, 2024, actual  
18 expenditures were included in the record.

19

20 **Q20. What are your thoughts on the historical accuracy of Nuclear Generation's**  
21 **capital projections?**

22 A20. In general, Nuclear Generation projections are accurate, in total. DTE Electric  
23 projected 2021 capital expenditures at \$150.9 million in Case No. U-20836 and  
24 then reported actual 2021 capital expenditures at \$149.7 million in the subsequent  
25 Case No. U-21297. DTE Electric projected 2022 capital expenditures at \$255.5

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1 million in Case No. U-21297 and then reported actual 2022 capital expenditures at  
2 \$254.5 million in the subsequent Case No. U-21534. DTE Electric projected 2023  
3 capital expenditures at \$156.7 million and projected 2024 capital expenditures at  
4 \$182.8 million in Case No. U-21534 and then reported actual 2023 capital  
5 expenditures at \$154.0 million and actual 2024 capital expenditures at \$186.9  
6 million in this proceeding. In aggregate, the Nuclear Generation actual expenditures  
7 discussed were within 0.1% of each previous rate-case's projected amounts.

8

9 **Q21. Do decisions made in the Commission's rate orders also impact historical**  
10 **projected expenditure performance?**

11 A21. Potentially, yes. Recall, that the Commission did not approve a significant portion  
12 of DTE Electric's incremental revenue requirement in its Case No. U-20836 Order,  
13 dated, November 18, 2022. Because of Company-wide impacts as a result of that  
14 Order, DTE Electric's projected the 2023 Nuclear Generation capital expenditures  
15 of \$200.7 million were ultimately reprioritized and managed to achieve 2023 actual  
16 expenditures of \$154.0 million.

17

18 More recently, proposed Staff disallowances based on AACE (that the Commission  
19 ultimately authorized) caused Nuclear Generation to reevaluate the urgency of  
20 certain projects to reduce financial risk to the Company. Projects such as plant  
21 wireless and sanitary sewer system replacements have the same importance for  
22 DTE Electric as discussed in Case No. U-21534 but timing has been adjusted to be  
23 better aligned with Commission's feedback.

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1   **Q22. Has the Commission not approved Nuclear Generation projected expenditures**  
2       **for not being reasonable or prudent?**

3   A22. No. At least not in the recent past. The Commission has not approved Nuclear  
4       Generation projected expenditures for having potentially uncertain projected  
5       amounts – and as I discuss throughout my direct testimony, DTE Electric has taken  
6       reasonable and prudent actions to address those previous concerns - but the  
7       Commission has been generally supportive of DTE Electric’s reasonable and  
8       prudent management of the Fermi 2 Power Plant and the prioritization of project  
9       expenditures to support safe and reliable operations.

10

11   **Q23. Before you discuss the discrete projects within the Nuclear Generation**  
12       **portfolio, can you summarize the principles and conduct of asset maintenance**  
13       **at a nuclear generation unit such as Fermi 2?**

14   A23. Nuclear safety is our overriding priority at Fermi 2 and, indeed, throughout the  
15       nuclear industry. Our operational and strategic decisions preserve this priority.

16

17   **Q24. What do you mean by nuclear safety?**

18   A24. Nuclear safety is focused on ensuring that we maintain and operate the Fermi 2  
19       nuclear asset with a high degree of rigor. Conservatism is necessary to minimize  
20       risk and ensure the safe and reliable use of nuclear material.

21

22   **Q25. What was the precipitating event that caused the US nuclear industry to**  
23       **prioritize nuclear safety?**

24   A25. The 1979 incident at Three Mile Island (TMI). The US nuclear industry formed the  
25       Institute of Nuclear Power Operations (INPO) as a direct result of the events at TMI

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1 and ultimately seeks to fulfill the recommendation of The President's Commission  
2 on the Accident at Three Mile Island (also known as the "Kemeny Commission")  
3 that the industry "set and police its own standards of excellence to ensure effective  
4 management and safe operation of nuclear power plants" after the Kemeny  
5 Commission concluded "that merely meeting the requirements of a government  
6 regulation does not guarantee safety."

7  
8 The Kemeny Commission changed the mind-set of the nuclear industry and its  
9 regulator – the Nuclear Regulatory Commission (NRC). The Kemeny Commission  
10 recognized that the nuclear industry leading into the TMI accident had the mind-  
11 set that the risk of nuclear accidents could be completely eliminated through better  
12 engineering and design of nuclear power plants and equipment and that this focus  
13 on design and equipment blinded the industry to the risks associated with human  
14 behavior and deprioritized efforts to establish sound radiological emergency plans  
15 to the federal, state and local levels. The Kemeny Commission recommendations  
16 forced an industry-wide reckoning of the human element within safe nuclear  
17 operations that called on the NRC, the commercial operators and even state rate-  
18 making agencies to recognize, change their mind-set, and reorganize themselves  
19 around the importance of human performance and leadership's priority of nuclear  
20 safety in all aspects of work.

21  
22 Post-Kemeny, the NRC reorganized into the modern agency we recognize today as  
23 not only licensing designs and plant construction but also overseeing ongoing  
24 operational nuclear safety. The Kemeny Commission recommendations can be  
25 considered the roots of the nuclear industry's self-critiquing/self-correcting

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1 behavior, its integrated and accredited training, its nuclear professionalism, and its  
2 development of high-quality and highly coordinated radiological emergency plans  
3 at federal, state, local and plant operator levels where nuclear safety is the  
4 overriding priority.

5

6 **Q26. How does DTE Electric manage nuclear safety risk?**

7 A26. DTE Electric manages nuclear safety risk through proper training, procedures and  
8 governance, operating the plant consistent with Fermi 2's Nuclear Regulatory  
9 Commission (NRC) operating license, operating the plant using the traits of a  
10 healthy nuclear safety culture (outlined in the World Association of Nuclear  
11 Operators (WANO) Principles PL 2013-1), and maintenance of the asset to support  
12 operation through 2045.

13

14 **Q27. What are the key principles the DTE Electric organization uses for**  
15 **maintaining the Fermi 2 nuclear asset?**

16 A27. I would summarize our key maintenance principles as:

17 1. Implementation of inspection, surveillance, maintenance and project activities  
18 are proactive and condition- or time-based to preclude a failure. Unanticipated  
19 equipment failures challenge plant operators and result in unplanned shutdowns  
20 or derates of the unit; our strategies are designed to minimize the probabilities  
21 of unanticipated equipment failures.

22 2. Work such as capital replacements and modifications are implemented when the  
23 plant is in the safest condition to do so. For most of our work at Nuclear  
24 Generation, that safest condition is when the Fermi 2 plant is shut down for a  
25 refueling outage.



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- 1           3. Work such as capital replacements and modifications are planned and executed  
2           in a reasonable and prudent manner consistent with the other key maintenance  
3           and project management principles.

4

5   **Q28. Why is it safest to perform maintenance on the Fermi 2 plant during a**  
6   **refueling outage?**

7   A28. Refueling outages are the safest time to perform maintenance for the following  
8   reasons:

- 9           1. Nuclear safety - our operating license issued by the NRC requires the plant to be  
10          shut down prior to taking many systems out of service for maintenance. These  
11          licensing requirements align with minimizing risks to health and safety.
- 12          2. Personnel safety – many areas of the plant are behind locked doors during  
13          operations due to the radiological or atmospheric conditions of the area.  
14          Refueling outages offer opportunities to access these otherwise inhospitable  
15          areas of the plant for maintenance.

16

17   **Q29. What is the cadence for the Fermi 2 plant refueling outages?**

18   A29. The Fermi 2 plant operates on a 24-month cycle, meaning every 24 months the  
19   Fermi 2 plant shuts down for a refueling outage. The Fermi 2 refueling outages are  
20   numbered sequentially and named as such: our winter/spring 2024 refueling outage,  
21   which was Fermi 2's twenty-second refueling outage, was named Refueling Outage  
22   22 or RF22 and Fermi 2's twenty-third refueling outage scheduled in the spring of  
23   2026 (approximately 24 months after RF22) is named Refueling Outage 23 or  
24   RF23.

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1   **Q30. What is the typical planning cadence for a Fermi 2 plant refueling outage?**

2   A30. Refueling outages are highly complex and require an integrated work plan to  
3       execute thousands of activities in a relatively short duration.

4  
5       Planning for a refueling outage is generally a two-year effort with many  
6       intermediate milestones guiding the planning effort; completion of these milestones  
7       requires consideration of the existing and projected material condition of the Fermi  
8       2 Power Plant as well as any practical constraints for safe execution of the projected  
9       work. The two most relevant of these milestones for capital expenditures are (1)  
10      two years prior to the refueling outage (T-24 months) Nuclear Generation confirms  
11      the Non-Routine and Large Projects for implementation in the outage and (2) at one  
12      year prior to the refueling outage (T-12 months) Nuclear Generation confirms for  
13      the Routine and Small Projects to be completed in the outage.

14

15   **Q31. How does the highly complex and integrated characteristic of refueling outage**  
16       **work impact project planning and execution?**

17   A31. Projects implemented during refueling outages are not stand-alone, independent  
18       projects as one may typically think of projects.

19

20       For example, plant workers such as plant operators, radiation protection, building  
21       trades and supervision are not dedicated to individual projects but must be shared  
22       across different projects and maintenance because qualified nuclear professionals  
23       are finite, nuclear standards are exacting, and gaining clearance to work at a U.S.  
24       nuclear plant is non-trivial; suppliers performing work must be chosen to globally  
25       improve outage execution - selecting suppliers as if projects were independent

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1 would lead to more expensive work, unnecessary duplication of oversight and  
2 potential conflicts between suppliers.

3  
4 As a second example, projects and maintenance activities may only occur in a  
5 specific schedule sequence which means performance of one project may impact  
6 performance of another project or projects.

7  
8 As I said, this coordination of work and resources is important to finalizing refueling  
9 outage plans and takes place in the cycle leading up to the refueling outage.

10

11 **Q32. How are suppliers chosen to globally improve work execution?**

12 A32. Suppliers of nuclear equipment, components and services are relatively limited and  
13 serve a relatively small group of U.S. nuclear power stations. As of December 31,  
14 2024, 94 U.S. commercial nuclear reactors were in commercial operations - and  
15 consolidation of suppliers is such that in many instances only one or two suppliers  
16 are qualified to provide certain nuclear components, equipment or services to  
17 nuclear power plants. Fermi 2 is further unique in that the plant is a General Electric  
18 Boiling Water Reactor Type 4 design (GE BWR/IV) with a Mark I containment  
19 structure and English Electric turbine/generator system. To be reasonable and  
20 prudent, selecting suppliers generally requires DTE Electric to weigh more than  
21 just the competitively bid costs: DTE Electric must consider supplier qualifications,  
22 safety record, original equipment manufacturer (OEM) status, incumbency, market  
23 share, industry operating experience and industry feedback, locality, ownership,  
24 union status and integration with the local building trades (if applicable), proposed  
25 schedule and costs, terms and conditions, likelihood of outcomes, amongst other

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1 factors. If a new participant enters a market, then supporting overall market  
2 competition can become a factor as well.

3

4 In general, DTE Electric secures long-term supplier agreements for Fermi 2 nuclear  
5 fuel, reactor services, turbine services, major maintenance services, heavy  
6 construction services, radiation protection services and engineering design services  
7 through competitive supplier sourcing and negotiation; DTE Electric periodically  
8 reviews or re-opens these long-term supplier agreements to ensure suppliers'  
9 pricing and quality remain competitive. Individual projects can then source, as  
10 needed, suppliers using these long-term agreements which facilitates each major  
11 supplier's resources being integrated into the overall work plan. DTE Electric  
12 sources other components, equipment and services in a reasonable and prudent  
13 manner consistent with the factors I outlined above.

14

15 **Q33. How does the highly complex and integrated characteristic of refueling outage**  
16 **work impact Nuclear Generation's project management phases?**

17 A33. As O&M activities and capital activities are highly integrated and closely  
18 coordinated at Fermi 2, Nuclear Generation's project management processes are  
19 interwoven with other work processes such that Nuclear Generation's project  
20 management processes may not be recognizable to those trained within a traditional  
21 engineering, procurement, construction (EPC) project management background.  
22 Nuclear Generation uses nuclear work management processes to manage capital  
23 projects as graded or modified approaches to capital project management is  
24 reasonable and prudent based on the scope and implementation of the capital  
25 projects. Nuclear Generation does not use a phase-gate approval process because

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1 the majority of Nuclear Generation's capital work is asset replacement, not new  
2 construction, and though there may be a design change (described later in my direct  
3 testimony), design change at a nuclear power plant is generally to maintain  
4 configuration control, not to necessarily design new equipment. This means that a  
5 generalized understanding of project management that may apply in other fields,  
6 such as new building construction, that includes steps such as (1) identify problem,  
7 (2) design solution, (3) solicit material and labor contracts, and (4) execute work,  
8 is not necessarily applicable to an operating nuclear power plant which more  
9 frequently engages in a "like-for-like"-type equipment replacement process. There  
10 are construction progress steps involved, but they are subject to substantial external  
11 constraints in terms of regulatory compliance, qualified vendors, and the ultimately  
12 required fit and function.

13

14 For example, when a pump motor is at end of life – this pump motor must be  
15 replaced because the Fermi 2 license requires the pump motor. DTE Electric  
16 identifies the new pump motor (likely from the only supplier that sells such a pump  
17 motor); however, the closest match to the existing pump motor is slightly different  
18 in electrical draw, mechanical mounting and fitting and size and weight. DTE  
19 Electric purchases the pump motor but now must perform a design change (plant  
20 modification) and update calculations to ensure the new electrical draw is  
21 accounted for and the weight of the new pump motor is seismically accounted for  
22 (a regulatory requirement). As the design change is occurring, DTE Electric may  
23 also be performing implementation tasks using its pre-approved labor suppliers.

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1 A rigid adherence to a phase-gate approval process would result in decision-making  
2 paralysis because the new pump motor must be purchased well before the design  
3 would ever be completed. It is this dynamic that leads Nuclear Generation to  
4 sometimes use a “partial” appropriation and then follow-up with a “full”  
5 appropriation to allow solicitation, procurement, design and implementation  
6 planning to all occur simultaneously at the initial stages, then as this initial work  
7 progresses, the full scope and expense of the project becomes clearer and the full  
8 appropriation can be reasonably authorized. Internal Company approvals for  
9 Nuclear Generation capital expenditures are provided in the Company’s Part III  
10 Attachment 15 supplemental filing materials. This approach is necessary,  
11 reasonable, and prudent.

12

13 **Q34. What work management/ project management milestones does DTE Electric**  
14 **status for Nuclear Generation capital expenditures?**

15 A34. Consistent with the industry’s refueling outage milestone processes, DTE Electric  
16 generally monitors a project’s appropriation status: no appropriation, initial/partial  
17 appropriation, full appropriation; a project’s modification status: no modification,  
18 modification in-progress, modification issued; a project’s scope status: initial  
19 scoping in-progress, initial scope complete, initial scope approved; a project’s  
20 commercial procurement status: procurement requires engineering, supplier  
21 sourcing event in-progress, contract awarded, material/service awarded; a project’s  
22 implementation status: in planning/ planning complete, ready-for-  
23 scheduling/scheduled, pre-outage activities in-progress/complete, outage activities  
24 in-progress/complete; and a project’s close-out status: in-service/not in-service,  
25 engineering and as-built documentation complete, and commercial documents

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1 closed. These project statuses can occur in parallel, in series, and in varying  
2 sequence depending on external constraints.

3

4 **Q35. How long has Fermi 2 been commercially operating?**

5 A35. Fermi 2 started commercial operations in 1988; however, Fermi 2's initial 40-year  
6 operating license term started March 20, 1985. The NRC approved Fermi 2's  
7 application for an initial 20-year license renewal in 2016. The term of Fermi 2's  
8 renewed operating license started March 20, 2025, at which time Fermi 2 began its  
9 Period of Extended Operations. Fermi 2's 20-year renewed operating license term  
10 ends March 20, 2045.

11

12 **Routine and Small Projects Capital Expenditures**

13 **Q36. Can you further explain the Routine and Small Projects summarized on line 2**  
14 **of Exhibit A-12, Schedule B5.3, page 1?**

15 A36. Routine and Small Projects are those capital expenditures associated with  
16 maintaining the various assets that support the safe operation of Fermi 2 and  
17 includes work such as pump, motor, valve and reactor control component  
18 replacements and can typically be expressed in number of units replaced. Routine  
19 and Small Projects are reasonable and prudent because these types of projects  
20 address commonly activated and used equipment that are the core of our proactive  
21 maintenance regime to maintain nuclear safety. Proactive replacement of these  
22 Fermi 2 components is essential to prioritizing nuclear safety by minimizing the  
23 potential for unanticipated or unrecoverable failures during plant operation.

Line  
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1 Pages 2-3 of Exhibit A-12, Schedule B5.3 provide a listing of the Routine and Small  
2 Projects that support page 1, line 2.

3

4 **Q37. Can you explain the Routine and Small Projects detailed in Exhibit A-12,**  
5 **Schedule B5.3, pages 2-3?**

6 A37. Exhibit A-12, Schedule B5.3, pages 2-3 show the by-project capital expenditures  
7 for Routine and Small Projects for the historical test year and the projected  
8 expenditures for the 24-month bridge forecast period ending December 31, 2025  
9 and the 12-month projected test period ending December 31, 2026 which total  
10 \$64.8 million, \$120.1 million and \$72.7 million respectively. Additional details for  
11 select routine and small projects are provided in Exhibit A-20, Schedule J2 and are  
12 also provided in the Part III (Attachments 9, 10 and 15) supplemental filing  
13 requirements.

14

15 The expenditures and project make-up are generally consistent each operating cycle  
16 and peak during refueling outage periods because of the regulatory and safety  
17 requirements governing Routine and Small Projects. I will later highlight specific  
18 Routine and Small Projects to help convey the type of projects that comprise  
19 Routine and Small Projects in my testimony.

20

21 **Q38. Prior to discussing the highlighted projects, can you please generally discuss**  
22 **the capital expenditures for the historical year ending December 31, 2023, the**  
23 **projected bridge years ending December 31, 2024 and December 31, 2025, and**  
24 **the projected test year ending December 31, 2026?**



Line  
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1 A38. Historical year ending December 31, 2023, was the year preceding a refueling  
2 outage (RF22 in spring 2024); many of the project expenditures (such as control  
3 rod drive mechanism (CRDM) replacements) in 2023 were associated with  
4 planning, readying and material procurement for RF22, which occurred in 2024.

5

6 The projected bridge year ending December 31, 2024, is the year that includes RF22  
7 and, as such, most of the Small and Routine expenditures are associated with  
8 projects (such as the Residual Heat Removal Service Water (RHRSW) outlet valve  
9 (F068A/B) replacement) which are now complete and went into service during  
10 RF22.

11

12 The projected bridge year ending December 31, 2025, is again a year that precedes  
13 a refueling outage (RF23 in spring 2026), and similar to the projected bridge year  
14 ending December 31, 2023, many project expenditures (such as control rod drive  
15 mechanism (CRDM) replacements) in 2025 are associated with planning, readying,  
16 and material procurement for RF23.

17

18 The projected test period ending projected bridge year ending December 31, 2026  
19 is the year that includes RF23 and, as such, most of the Small and Routine  
20 expenditures are associated with projects which are projected to complete and to be  
21 placed into service during RF23 as well as Large and Non-Routine projects such as  
22 the Main Unit Generator Replacement and Feed Water Heater Replacements.

23

24 **Q39. Does the general expenditure pattern just described apply to multi-year**  
25 **projects such as the Security System Computer replacement project shown on**

Line  
No.

1           **line 2, Plant Radio System project shown on line 3, and Plant Wireless project**  
2           **shown on line 13 on Exhibit A-12, Schedule B5.3, page 2?**

3    A39.   No. Security System Computer, Plant Radio System and Plant Wireless projects  
4           are examples of multi-year Routine and Small Projects with predominately online  
5           implementation, so the general pattern of Routine and Small Projects expenditures  
6           just discussed is not as relevant to these projects. Because these projects are multi-  
7           year, I previously discussed these three projects in DTE Electric Rate Case Nos. U-  
8           20836, U-21297 and U-21534; nonetheless, because of their continued importance  
9           to our nuclear safety paradigm, I will again highlight these projects here.

10

11   **Q40. Can you discuss the expenditures and rationale for the Security System**  
12           **Computer replacement project shown on Exhibit A-12, Schedule B5.3, page 2,**  
13           **line 2?**

14    A40.   The Security System Computer replacement project replaced the Fermi 2 Security  
15           System Computer which includes specialized computer servers, video cameras,  
16           other access control and detection devices, and communication cabling. The  
17           replacement project was completed and the project was placed in-service in  
18           February 2025. The Security System Computer replacement project capital  
19           expenditures for the historical test year, projected bridge forecast period and  
20           projected test period are \$17.0 million, \$16.1 million and \$0.0 million respectively.

21

22           The Security System Computer replacement project addressed aging and  
23           obsolescence of the existing security system; this replacement project also included  
24           construction of an additional access control building to improve security response  
25           margins. This major plant security system is an aspect of the regulatory-required

Line  
No.

1 Fermi 2 Security Protection Plan per Code of Federal Regulation 10 CFR 73.55  
2 which requires a physical security plan that must “ensure that the capabilities to  
3 detect, assess, interdict, and neutralize threats up to and including the design basis  
4 threat of radiological sabotage as stated in 10 CFR 73.1, are maintained at all times”  
5 and “provide defense-in-depth through the integration of systems, technologies,  
6 programs, equipment, supporting processes, and implementing procedures as  
7 needed to ensure the effectiveness of the physical protection program.”

8

9 **Q41. Why was replacement of the security system computer necessary within the**  
10 **projected test period?**

11 A41. Components of the existing security system computer have exhibited decreased  
12 performance as service time has increased. Degradation of security equipment  
13 results in multiple alarms that distract the security force from core activities,  
14 requires compensatory measures which require unscheduled overtime, requires  
15 emergent maintenance, and increases the risk of gaps in meeting the regulatory  
16 requirements. In 2022, one of the intrusion detection systems accumulated three  
17 times more annual out of service time than it did in 2021, indicating a need to  
18 replace the system. Repair and replacement of existing components has become  
19 increasingly difficult as equipment becomes obsolete; for example, vendor  
20 supported software updates ceased for the security system computer’s video  
21 monitoring software, video server operating system, and the server and workstation  
22 operating system in 2015, 2016 and 2020 respectively. Lack of vendor support for  
23 these operating systems or video monitoring systems could lead to extended loss of  
24 security video feeds which would require additional security personnel to  
25 compensate for the loss of video surveillance.

Line  
No.

1 A security system computer used in the security of a nuclear power plant can be  
2 reasonably expected to be in service for approximately 10 – 15 years based on  
3 anticipated aging and obsolescence factors. Aspects of the Fermi 2 security system  
4 computer such as the communications cabling have been in service for more than  
5 thirty years; while the security system computer servers, workstations and access  
6 controls hardware is comparatively newer – this hardware still relies on late-2000s  
7 vintage technology. NRC cyber security regulations and the deeply integrated  
8 nature of the security system computer makes replacement components  
9 increasingly impractical to procure.

10

11 Preemptive replacement of the security system computer and its constituent  
12 components is a reasonable and prudent action, consistent with our nuclear safety  
13 priorities to support DTE Electric continuing to meet its regulatory commitments  
14 into the 2030s when DTE Electric anticipates the next routine replacement of the  
15 security system computer to occur. Several portions of this project also bring  
16 equipment and strategy up to nuclear industry standards. Additionally, these  
17 replacements will allow for more efficient equipment maintenance.

18

19 The integrated project also includes the addition of equipment, for example,  
20 additional cameras, and changes to the location of some equipment to support  
21 satisfactory outcomes from NRC-graded Force-on-Force exercises as well as a  
22 formal assessment of the Security Strategy.

Line  
No.

1   **Q42. What is the role of the security system computer within the nuclear safety**  
2   **paradigm you discussed earlier in your testimony?**

3   A42. The security system computer itself is an aspect of the Fermi 2 Physical Security  
4   Plan (the exact details of physical security plans are safeguarded and protected per  
5   regulation) – having and maintaining Fermi 2’s security equipment in accordance  
6   with the approved physical security plan is a regulatory requirement and a condition  
7   to maintaining the Fermi 2 operating license. Because the consequences of hostile  
8   actors acting against a U.S. commercial nuclear plant are significant, each U.S.  
9   commercial nuclear site’s physical security plan is routinely inspected and tested  
10   by the NRC to ensure compliance. DTE Electric has an obligation to ensure that all  
11   aspects of the Fermi 2 physical security plan work and will continue to work in the  
12   future – hence a preemptive replacement regimen is necessary to ensure  
13   components of the security computer systems do not unexpectedly or  
14   unrecoverably fail.

15

16   As DTE Electric replaces the existing security computer systems, Fermi 2 must  
17   remain in compliance with regulations such that: (1) the functions and capabilities  
18   of the existing security computer systems must be maintained while the new system  
19   is being installed, (2) design, configuration control and work to replace the existing  
20   security computer systems must be performed so as to maintain operability of other  
21   Fermi 2 plant systems including taking special care when excavating to replace  
22   cabling and other components, (3) the new security computer systems must meet  
23   NRC cyber security requirements, (4) the new system must be designed and tested  
24   for continuous operations with minimal maintenance time. Total project  
25   expenditures are commensurate with these regulatory requirements.

Line  
No.

1   **Q43. Was the Security System Computer project competitively sourced?**

2   A43. Yes. Consistent with the commercial principles I discussed earlier, the Security  
3       System Computer project uses competitively-sourced suppliers. While commercial  
4       processes and agreements are sensitive information, DTE Electric provides relevant  
5       sourcing documents, subject to Protective Orders, in the ordinary course of  
6       proceedings; other supplier and project information can be found in this  
7       proceeding's Part III, Attachment 9 supplement filing.

8

9       Total project costs reasonably and prudently reflect actual and projected costs based  
10      on the commercial solicitations and agreements. As I discussed earlier, commercial  
11      solicitation processes, such as competitive sourcing, is a principle of prioritizing  
12      nuclear safety to support safe, reliable and efficient project execution and post-  
13      implementation equipment operations.

14

15   **Q44. Can you discuss the expenditures and rationale for the Plant Radio System**  
16       **replacement project shown on Exhibit A-12, Schedule B5.3, page 2, line 3?**

17   A44. The Plant Radio System replaced the existing Fermi 2 plant radio system which  
18       includes computers, radio repeaters, radio antenna, uninterruptible power supplies  
19       and communications cabling. This replacement project was completed in 2025 and  
20       placed in-service in February 2025. The Plant Radio System replacement project  
21       capital expenditures for the historical test year, projected bridge forecast period and  
22       the projected test period are \$6.0 million, \$5.1 million and \$0.0 million  
23       respectively.

Line  
No.

1 This major system is an aspect of the regulatory-required Fermi 2 Physical Security  
2 Plan and the regulatory-required Fermi 2 Radiological Emergency Response Plan  
3 and has the purpose to be the primary means of communication for plant personnel  
4 including site security and fire brigade during operations and potential accident  
5 scenarios; loss of the plant radio system would degrade plant operators' ability to  
6 safely operate the Fermi 2 Power Plant.

7

8 **Q45. Why is replacement of the plant radio system necessary within the projected**  
9 **test period?**

10 A45. Security and operations vulnerabilities. Replacement of the plant radio system  
11 began in 2017 with the replacement of plant radio equipment in the Fermi 2 Main  
12 Control Room (MCR); field radio communications to the MCR were becoming  
13 increasingly inaudible within the MCR which was unduly burdening plant  
14 operators during plant operations. Additionally, radio communications within the  
15 power plant uses an antenna system installed in the early 1980s, experiences a  
16 significant signal loss between the base station and the distributed antennas and is  
17 capable of transmitting only the UHS frequency band. Replacement of the plant  
18 radio system distributed antenna system, communications cabling and  
19 uninterruptible power supplies (which is the scope of work during the bridge and  
20 projected test periods in this case) will improve plant radio signal fidelity  
21 throughout the plant and add two additional radio frequencies bands (VHS and 800  
22 MHZ) within the power plant.

Line  
No.

1 Improving plant radio signal fidelity within the plant supports improved operations  
2 communications, especially for emergency responders such as fire brigade in all  
3 areas of the plant.

4  
5 Adding the two additional radio frequency bands also allows DTE Electric to  
6 evaluate changes to the Fermi 2 Physical Security Plan, further improves Fermi 2's  
7 security posture and enhances security's communication capabilities with outside  
8 emergency responders such as the Michigan State Police.

9

10 **Q46. What is the role of the plant radio system within the nuclear safety paradigm**  
11 **you discussed earlier in your testimony?**

12 A46. The plant radio system is an aspect of the Fermi 2 Radiological Emergency  
13 Response Plan – having and maintaining Fermi 2's plant radio equipment in  
14 accordance with the approved emergency response plan is a regulatory requirement  
15 and a condition to maintaining the Fermi 2 operating license. Because the  
16 consequences of an ineffective radiological emergency response are significant,  
17 each U.S. commercial nuclear site's emergency response plan is routinely inspected  
18 and tested by the NRC and the Federal Emergency Management Agency (FEMA)  
19 to ensure compliance. DTE Electric has an obligation to ensure that the components  
20 of the Fermi 2 Radiological Emergency Response Plan work and will continue to  
21 work in the future – hence a preemptive replacement regimen is reasonable and  
22 prudent.

23

24 The plant radio system is the primary communication means for plant operators and  
25 security officers responding to emergency conditions – unexpected or unrestorable



Line  
No.

1 failure or interruption of this equipment would be an unacceptable risk to first  
2 responders to any Fermi 2 plant emergency; it is imperative that the plant radio  
3 system maintains its capabilities throughout the plant and through all postulated  
4 operating scenarios.

5  
6 As Fermi 2 replaces the existing plant radio system, the Company must remain in  
7 compliance with regulations such that: (1) the functions and capabilities of the  
8 existing plant radio system must be maintained while the new system is being  
9 installed, (2) design, configuration control and work to replace the existing plant  
10 radio system must be performed as to maintain operability of other Fermi 2 plant  
11 systems, (3) the new plant radio system must meet NRC cyber security  
12 requirements, and (4) the new system must be designed and tested for continuous  
13 operations with minimal maintenance time. This requires installing 16 new  
14 antennae and approximately 5800 feet of new conduit and cable. Total project  
15 expenditures are commensurate with these regulatory requirements.

16  
17 **Q47. Can you discuss the expenditures and rationale for the Plant Wireless project**  
18 **shown on Exhibit A-12, Schedule B5.3, page 2, line 13?**

19 A47. The Plant Wireless project as depicted on Exhibit A-12, Schedule B5.3, page 2, line  
20 13 replaces and expands the existing Fermi 2 plant wireless system which includes  
21 modems, network switches, and wireless antennae. This replacement and expansion  
22 project is projected to be complete and placed in-service in 2028. The Plant  
23 Wireless project capital expenditures for the historical test year, projected bridge  
24 forecast period and the projected test period are \$1.9 million, \$2.7 million and \$0.0  
25 million respectively and would extend beyond the projected test period.

Line  
No.

1 The purpose of the plant wireless system is to provide wireless data communications  
2 capacity to plant personnel during normal operations; not replacing and expanding  
3 the plant wireless system would challenge operations to effectively operate the  
4 plant. In addition, the Plant Wireless project is resource-optimized with the Plant  
5 Radio System replacement project by sharing the conduit and cable trays.

6

7 **Q48. What is the role of the plant wireless system within the nuclear safety**  
8 **paradigm you discussed earlier in your testimony?**

9 A48. Installation of a wireless communication backbone throughout the nuclear power  
10 block directly impacts the ability to progress with other cost-savings and  
11 radiological dose-savings initiatives (maintaining acceptable radiological dose for  
12 plant workers is a regulatory requirement and reducing radiological dose wherever  
13 possible is a continuing industry safety practice) including Electronic Work Orders,  
14 Electronic Operator Rounds, remote dose monitoring and remote equipment  
15 monitoring. NRC regulations require management measures which include  
16 configuration management, maintenance, training and certification, procedures,  
17 records management, and other quality assurance methods, generally on a  
18 continuing basis, that are applied to items relied on for safety, to ensure the items  
19 are available and reliable to perform their functions when needed. Plant wireless  
20 system provides the networking infrastructure and capacity necessary for Fermi 2  
21 to modernize and maintain these management measures. Plant wireless networks  
22 are used in the nuclear industry to provide efficiency in recording and automatically  
23 storing regulatory-required documentation and for additional monitoring of  
24 equipment important to nuclear safety and plant reliability without incurring the  
25 large costs of permanent imbedded cabling.

Line  
No.

1 Existing management measures require controlled paper copies of work orders,  
2 plant drawings, engineering design documents, purchasing agreements, time sheets  
3 and procedures in the field – not that different from when the Fermi 2 first started  
4 commercial operations in 1988. While these paper-document management  
5 measures continue to support safe and reliable operations, modern industry-best  
6 practices have evolved to use paperless work orders and procedures, automated  
7 document control and records management, and electronic time keeping systems to  
8 reduce human error precursors and to maintain positive configuration control of the  
9 plant.

10

11 As DTE Electric replaces and expands the existing plant wireless system, the  
12 Company must remain in compliance with regulations such that: (1) design,  
13 configuration control and work to replace and expand the existing plant wireless  
14 system must be performed so as to maintain operability of other Fermi 2 plant  
15 systems, (2) wireless network signals from the plant wireless system must strike a  
16 difficult engineering balance between strong signal strength and bandwidth against  
17 requirements that the signals not interfere with the function of other plant  
18 equipment and (3) the new plant wireless system must meet NRC cyber security  
19 requirements. Total project expenditures are commensurate with these regulatory  
20 requirements.

21

22 **Q49. What do you mean by “aging and obsolescence?”**

23 A49. Aging in the context of nuclear plant operations refers to the general process in  
24 which characteristics of equipment or components gradually degrade with time or  
25 use.

Line  
No.

1 Component obsolescence in the context of nuclear plant operations refers to  
2 equipment or components that are no longer manufactured or qualified by their  
3 original manufacturers.

4

5 **Q50. Why is obsolescence a particular concern for DTE Electric at the Fermi 2**  
6 **Power Plant?**

7 A50. I have discussed aging and obsolescence a few times already because aging and  
8 obsolescence concerns are not just a focus for DTE Electric, but a focus for the  
9 entire U.S. nuclear industry. Configuration management at a nuclear power plant  
10 specifies allowed components by manufacturer and model number. Once  
11 manufacturers cease operations, change ownership or cease production of a  
12 particular model, nuclear operators must identify potential replacements. This  
13 process of identifying potential replacements is rigorous as all aspects of the  
14 potential replacement's fit, form, and function must be evaluated by qualified  
15 engineers. Potential replacements may also require physical modification to the  
16 plant to be usable – Security System Computer is one such project that required  
17 modifications to the Fermi 2 plant to address aging and obsolescence.

18

19 Unexpected or unrecoverable failures of obsolete components are a vulnerability to  
20 safe and reliable plant operations. Of course, as components age, the vulnerability  
21 of unrecoverable failure increases. Unexpected or unrecoverable failures of  
22 obsolete components could result in the extended compensatory measures that  
23 burden operations, security, or other plant personnel; shutdown of the plant is also  
24 a possibility until potential replacements are identified and actions are taken to  
25 make the replacement usable within the plant.

Line  
No.

1   **Q51. What actions must a nuclear operator such as DTE Electric take to physically**  
2       **modify the plant?**

3   A51. When new or replacement components or equipment require a plant modification,  
4       in addition to the physical field work of the modification there are several  
5       management actions required: (1) plant drawings and component databases must  
6       be updated, (2) plant calculations must be revised to ensure sufficient structural  
7       loading or electrical loading margins exist, (3) physical security and emergency  
8       response plans must be evaluated and possibly revised, (4) operating license and  
9       safety analysis reporting must be evaluated and possibly revised, and (5) training,  
10      operations and maintenance programs must be evaluated and possibly revised.

11

12      The resources, time, and costs of these regulatory-required management measures  
13      are non-trivial.

14

15   **Q52. Can you discuss the expenditures and rationale for the Undervessel**  
16       **Replacements project shown on Exhibit A-12, Schedule B5.3, page 2, line 31?**

17   A52. I previously discussed the routine Undervessel Replacements project, as well as the  
18       related projects involving Control Rod Blade Replacements and Control Rod Drive  
19       Mechanisms Replacements, in Case No. U-21534. DTE Electric has depicted the  
20       ongoing and updated capital expenditures for these projects in each DTE Electric  
21       rate case dating back to at least U-16472 without contention. I would like to again  
22       explain the importance of these Routine and Small Projects with a discussion here,  
23       starting with the Undervessel Replacements project. The Undervessel  
24       Replacements capital expenditures for the historical test year, projected bridge  
25       forecast period and projected test period are \$0.2 million, \$10.2 million, and \$8.0

Line  
No.

1 million respectively. These expenditures do extend beyond the projected test period  
2 and through the balance-of-life of the Fermi 2 Power Plant, address component  
3 aging, and support the necessary replacement of undervessel components which  
4 include control rod drives and nuclear instrumentation such as local power range  
5 monitors (LPRMs). The purpose of undervessel components goes to the heart of  
6 safely operating a nuclear reactor and directly affects control and monitoring of  
7 power levels throughout the reactor core (undervessel components are so named  
8 because the components are driven by equipment located underneath the reactor  
9 pressure vessel); unplanned or unrecoverable loss of these components would  
10 challenge plant operator's ability to safely operate the Fermi 2 plant.

11

12 **Q53. Can you discuss the expenditures and rationale for the Control Rod Blade**  
13 **Replacements project shown on Exhibit A-12, Schedule B5.3, page 2, line 10?**

14 A53. The Control Rod Blade (CRB) Replacement project capital expenditures for the  
15 historical test year, projected bridge forecast period and projected test period are  
16 \$2.5 million, \$0.8 million, and \$1.2 million respectively, do extend beyond the  
17 projected test period and through the balance-of-life of the Fermi 2 Power Plant,  
18 closely relates to the Undervessel Replacements projects, address CRB component  
19 aging, and support the necessary replacement of the CRBs (DTE Electric replaced  
20 22 CRBs in RF22 and projects replacement of 19 CRBs in RF23). The purpose of  
21 Fermi 2's 185 CRBs is to control power levels within the reactor core and to  
22 ultimately safely accomplish shut down of the reactor when appropriate; unplanned  
23 or unrecoverable loss of the CRBs would challenge plant operator's ability to safely  
24 operate the Fermi 2 plant.

Line  
No.

1   **Q54. Can you discuss the expenditures and rationale for the Control Rod Drive**  
2       **Mechanism Replacement project shown on Exhibit A-12, Schedule B5.3, page**  
3       **2, line 4?**

4   A54. The Control Rod Drive Mechanism (CRDM) replacement project capital  
5       expenditures for the historical test year, projected bridge forecast period and  
6       projected test period are \$4.6 million, \$4.6 million, and \$0.5 million respectively,  
7       do extend beyond the projected test period and through the balance-of-life of the  
8       Fermi 2 Power Plant, closely relates to the Undervessel Replacements projects,  
9       address CRDM component aging, and support the necessary replacement of the  
10      CRDMs (DTE Electric replaced 20 CRDMs in RF22 and projects to replace 20  
11      CRDMs in RF23 (spring 2026)). The purpose of Fermi 2's 185 CRDMs is to control  
12      power levels within the reactor core and to ultimately safely accomplish shut down  
13      of the reactor upon receiving either manual or automatic signals; unplanned or  
14      unrecoverable loss of the CRDMs would challenge plant operator's ability to safely  
15      operate the Fermi 2 plant.

16

17   **Q55. Why is Fermi projecting to replace 19 CRBs in RF23 and 20 CDRMs in RF23?**

18   A55. Although CRBs and CRDMs are part of the same control rod drive system, the  
19      aging mechanism is very different between CRDMs and CRBs. CRDMs (hydraulic  
20      piston assemblies located underneath the reactor pressure vessel) are subject to  
21      harsh environmental conditions such as extreme heat, moisture and radiation; after  
22      time, the components of the CRDM will naturally stress, fatigue and wear and must  
23      be replaced. CRBs (crucible-shaped, metal-tube components that contain a neutron-  
24      absorbing material located inside the reactor core adjacent to fuel assemblies) are  
25      subject to the extreme environment of the reactor itself; after time, the neutron-

Line  
No.

1 absorbing material is consumed preventing it from fully performing its function to  
2 shutdown the reactor or the CRB structural material will stress, fatigue and wear  
3 and may become damaged during operation which could directly impact fuel  
4 integrity.

5  
6 Each component of the control rod drive system must be evaluated and replaced on  
7 its own schedule. For CRBs, DTE Electric determines this schedule based on  
8 analysis of the operational history of the individual CRBs, calculates remaining  
9 useful core life, and performs confirmatory testing to ensure the CRBs perform as  
10 expected. For CRDMs, DTE Electric levelizes the replacements of the CRDMs  
11 over their approximately 12-cycle in-service life.

12

13 **Q56. What is the status of the commercial agreements for the Undervessel**  
14 **Replacements, CRBs and CRDMs?**

15 A56. DTE Electric has negotiated long-term commercial agreements (using the  
16 commercial principles I discussed earlier) for the OEM suppliers to provide these  
17 vital nuclear components and services through at least 2027. These long-term  
18 agreements provide DTE Electric with high assurance of adequate supply of  
19 nuclear-quality plant components at predictable quality, compatibility and cost –  
20 which is certainly reasonable and prudent.

21

22 **Non-Routine and Large Projects Capital Expenditures**

23 **Q57. Can you discuss the Non-Routine and Large Projects summarized on line 3 of**  
24 **Exhibit A-12, Schedule B5.3, page 1?**



Line  
No.

1 A57. Non-Routine and Large Projects are projects that are necessary to properly maintain  
2 the Fermi 2 asset and are incremental to normal routine capital expenditures. Non-  
3 Routine and Large Projects also include the once-in-a-plant-lifetime replacements  
4 which would not have been otherwise required except for Fermi 2 beginning its  
5 Period of Extended Operations which starts in March 2025.

6

7 Refer to Page 4 of Exhibit A-12, Schedule B5.3 for a listing of the projects that  
8 support page 1, line 3.

9

10 **Q58. Can you explain the Non-Routine and Large Projects detailed in Exhibit A-12,**  
11 **Schedule B5.3, page 4?**

12 A58. Yes. This exhibit shows the by-project capital expenditures for Non-Routine and  
13 Large Projects, as noted by line 3 of Exhibit A-12, Schedule B5.3, page 1. These  
14 projects for the historical test year, the projected expenditures for the 24-month  
15 bridge forecast period ending December 31, 2025, and the 12-month projected test  
16 period ending December 31, 2026, total \$89.2 million, \$145.1 million and \$114.5  
17 million respectively. A discussion of certain Non-Routine and Large Projects  
18 follows with additional details for other Non-Routine and Large Projects provided  
19 in the Part III (Questions 9 and 10) supplemental filing documents.

20

21 **Q59. Can you explain the expenditures and rationale for the Main Unit Generator**  
22 **project shown on line 2 of Exhibit A-12, Schedule B5.3, page 4?**

23 A59. The Main Unit Generator Replacement project as depicted on line 2 is to replace  
24 the Fermi 2 main unit generator stator and rotor. This replacement is projected to  
25 occur during RF23 (Spring 2026) and the project has a projected in-service year of

Line  
No.

1 2026. This project has capital expenditures for the historical test year, projected  
2 bridge forecast period and projected test period of \$33.8 million, \$61.5 million and  
3 \$45.8 million respectively.

4  
5 The main unit generator project replaces the Fermi 2 main unit generator which is  
6 original to plant construction and at the end of its service life; this replacement also  
7 serves to address an Original Equipment Manufacturer (OEM) design vulnerability  
8 and to improve overall reliability through 2045. Replacement of this model of  
9 generator is the identical approach other nuclear generation owners have taken over  
10 the years to mitigate operational risk.

11

12 **Q60. Does DTE Electric have possession of the replacement main unit generator**  
13 **stator?**

14 A60. Yes. As of January 1, 2025, the replacement main unit generator stator was safely  
15 staged on the Fermi 2 turbine deck inside the Fermi 2 Turbine Building and is  
16 awaiting installation in RF23.

17

18 **Q61. Can you discuss the operational history of the Fermi 2 main unit generator?**

19 A61. The existing Fermi 2 generator experienced a stator coil leak that resulted in a 43.8-  
20 day outage in 2009, again experienced a stator coil leak that resulted in a 55.2-day  
21 outage in 2012 and had an indication of a ground within its rotor in 2019 that  
22 resulted in a 25.8-day outage. To date, multiple known vulnerabilities and  
23 degradation have been mitigated through increased maintenance bridging  
24 strategies; however, unique-to-model design vulnerabilities associated with the  
25 existing stator continue to represent increased risk for sudden failure. Unplanned or

Line  
No.

1 unexpected failures not only present a generation risk but also present operational  
2 risk to the plant operators responsible for maneuvering the plant to a shutdown  
3 condition following a generator failure.

4

5 **Q62. What is the purpose of the Fermi 2 main unit generator?**

6 A62. The Fermi 2 main unit generator is a component of the Fermi 2 power conversion  
7 systems which is more fully described in Fermi 2's USFAR Chapter 10 Steam and  
8 Power Conversion (publicly available at nrc.gov) and, for convenience, is included  
9 in the supplemental filing materials. The purpose of the Fermi 2 main unit generator  
10 is to convert the mechanical, rotational energy of the Fermi 2 main turbine into  
11 electrical energy.

12

13 **Q63. Does the main unit generator have a nuclear safety function?**

14 A63. No. As explained in Chapter 10 of the Fermi 2 USFAR, none of the components of  
15 the power conversion systems are required to operate to ensure a safe reactor  
16 shutdown. Fermi 2's reactor safety systems are designed to protect the reactor under  
17 all conditions which includes complete isolation from the power conversion  
18 systems; therefore, reliability of power conversion systems, with the exception for  
19 control of radioactivity, is primarily a function of electrical grid system operating  
20 requirements.

21

22 Though the main unit generator is not required for safe reactor shutdown, an  
23 unexpected or sudden failure of the generator could still challenge plant equipment  
24 and operators' ability to shut down the reactor without complications; as such,  
25 pursuit of a reliable main unit generator is a reasonable and prudent objective.

Line  
No.

1   **Q64. How does replacement of the Fermi 2 main unit generator provide a benefit to**  
2       **the community?**

3   A64. Fermi 2's nuclear generation technology is amongst the most resilient electricity  
4       generation sources available to our community – the Fermi 2 Power Plant operates  
5       day and night, wind and no-wind, freezing-cold and sweltering-hot, generating  
6       approximately 1170 MWs of carbon-free electricity . Unlike other forms of thermal  
7       generation where a unit may have multiple generators, the main unit generator is  
8       the single asset at Fermi 2 Power Plant designed to convert mechanical energy into  
9       electricity for transmission to the electric grid and because the plant operates at its  
10      full generation capacity throughout the two-year operating cycle the safety and  
11      reliability of the main unit generator must be reasonably assured for Fermi 2 Power  
12      Plant to continue to provide such benefits to our communities.

13

14      The existing Fermi 2 main unit generator is simply not reliable enough to provide  
15      long-term reasonable assurance of reliable operations, especially considering Fermi  
16      2 is licensed to operate until 2045 with potential to subsequently renew the Fermi  
17      2 license for operations to continue until 2065. The existing Fermi 2 generator  
18      (stator) is the original plant equipment, manufactured in the early 1970s using the  
19      technology of that time and has reached its end of life (EOL). The existing generator  
20      has been the cause of three Fermi 2 outages since 2009. Because of the design of  
21      the existing generator, replacement of the main unit generator is the only action that  
22      will result in a reduction of risk to Fermi 2's generation reliability which, in turn,  
23      will result in potential incremental carbon-free electricity generation for the  
24      community.

Line  
No.

1 Also, we must recognize the potentially immense value of the Inflation Reduction  
2 Act (IRA) of 2022 nuclear production tax credits (PTCs) for existing nuclear power  
3 plants – which have a maximum value of \$15/MWH. In 2024, DTE Electric  
4 recognized a PSCR reduction of approximately \$120 million due to the IRA’s  
5 nuclear PTCs resulting from Fermi 2’s safe, reliable generation (See DTE Electric  
6 2024 PSCR Reconciliation Case No. U-21426, Exhibit A-13). The replacement of  
7 the main unit generator is necessary to maintain margins for safe, reliable Fermi 2  
8 operations (as a degraded or damaged main unit generator results in a complete  
9 shutdown of the Fermi 2 Power Plant to remediate) which in turn maximizes DTE  
10 Electric’s opportunity to earn these valuable nuclear PTCs.

11

12 Implementing the Main Unit Generator Replacement project in RF23 is a  
13 reasonable and prudent action because of the current state described above. DTE  
14 Electric has taken reasonable and prudent measures to ensure this once-in-a-plant-  
15 lifetime replacement was manufactured to a standard supporting safe and reliable  
16 plant operations through at least 2045 while also mitigating the short-term  
17 reliability risks associated with the existing Fermi 2 main unit generator.

18

19 **Q65. Can you discuss the expenditures and rationale for the General Service Water**  
20 **(GSW) intake groin replacement shown on line 3 of Exhibit A-12, Schedule**  
21 **B5.3, page 4?**

22 A65. The General Service Water (GSW) intake groin replacement project depicted on  
23 line 3 restored the GSW intake groins. This project completed in 2024 and the  
24 project has been placed in-service. The General Service Water (GSW) intake groin  
25 replacement project capital expenditures for the historical test year, projected

Line  
No.

1 bridge forecast period and projected test period are \$18.0 million, \$0.1 million, and  
2 \$0.0 million respectively, and do not extend beyond the projected test period.

3

4 The GSW intake groin replacement project addressed natural erosion of the existing  
5 GSW intake groin structure which was original to plant construction and at the end  
6 of its service life.

7

8 **Q66. What is the purpose of the Fermi 2 GSW intake groins?**

9 A66. The Fermi 2 GSW intake groins are a component of the Fermi 2 General Service  
10 Water system which is more fully described in Fermi 2's USFAR Chapter 9  
11 Auxiliary Systems. The Fermi 2 GSW system provides cooling water (directly  
12 drawn from Lake Erie) to remove various plant heat loads during normal operation;  
13 unplanned or unrecoverable loss of the GSW would challenge the plant operator's  
14 ability to safely operate the Fermi 2 plant.

15

16 The Fermi 2 GSW intake groin structure is comprised of two armored-earthen  
17 jetties that jut into Lake Erie; the jetties' armor is a layered system of rock and  
18 concrete tetrapods which are designed to mitigate Lake Erie erosion action and yet  
19 allow enough movement within the armor structure itself to mitigate Lake Erie ice  
20 action from damaging the armor. The purpose of the Fermi 2 GSW intake groin  
21 structure is to protect the Fermi 2 GSW intakes from Lake Erie wave action,  
22 minimize bio-material accumulation at the GSW intake and to minimize sediment  
23 accumulation at the GSW intake.

24

25 **Q67. Does the GSW intake structure have a nuclear safety function?**

Line  
No.

1 A67. No. As explained in Chapter 9 of the Fermi 2 USFAR, none of the components of  
2 the GSW system are required to be operable to effect safe shutdown of the Fermi 2  
3 Power Plant; therefore, reliability of the GSW system is primarily a function of  
4 electrical grid system operating requirements.

5  
6 **Q68. How does replacement of the Fermi 2 GSW intake groins provide a benefit to**  
7 **the community?**

8 A68. Replacement of the GSW intake groins provided the Fermi 2 Power Plant with  
9 improved margins against risk of loss of GSW which, in turn, results in potential  
10 incremental carbon-free generation for the community.

11  
12 **Q69. Can you discuss the expenditures and rationale for the Underground Safety-**  
13 **Related Service Water Piping project shown on line 4 of Exhibit A-12,**  
14 **Schedule B5.3, page 4?**

15 A69. The Underground Safety-Related Service Water Piping project as depicted on line  
16 4 is to replace the Fermi 2 underground portions of the safety-related service water  
17 piping associated with the Emergency Equipment Service Water (EESW) and the  
18 Residual Heat Removal System Water (RHRSW) systems. This replacement  
19 project completed during RF22 (Spring 2024) and the project has been placed in-  
20 service. This project has capital expenditures for the historical test year, projected  
21 bridge forecast period and projected test period of \$10.5 million, \$18.8 million and  
22 \$0.0 million respectively.

23  
24 The prior underground safety-related service water piping was original to plant  
25 construction and had been in service for over forty years. Replacement of the

Line  
No.

1 underground safety-related service water piping was necessary to address age-  
2 related degrading pipe-wall thickness and to ensure this pipe will continue to  
3 support plant operations through the end of the operating license in 2045.

4

5 **Q70. What does it mean to be “safety-related” piping?**

6 A70. In the U.S. nuclear industry, the term “safety-related” applies to systems, structures,  
7 components, procedures, and controls that are relied upon to remain functional  
8 during and following design-basis events. Per NRC regulations, materials,  
9 equipment and components of safety-related systems have very strict  
10 manufacturing tolerances and quality control; new materials, equipment and  
11 components are inspected against technically developed procurement  
12 specifications. Post-delivery modifications to safety-related materials such as  
13 cutting, fitting and welding pipe must be to design, properly controlled, traceable,  
14 and work inspected by qualified inspectors. Work on safety-related equipment  
15 requires an exactness in performance that is not common in non-nuclear industry.

16

17 **Q71. What is the purpose of the safety-related service water piping?**

18 A71. The Fermi 2 EESW and RHRSW systems are a component of the Fermi 2 auxiliary  
19 systems which is more fully described Fermi 2’s USFAR Chapter 9 Auxiliary  
20 Systems. The purpose of the Fermi 2 RHRSW and EESW piping is to transport  
21 equipment cooling water from the Fermi 2 emergency water reservoir (known as  
22 the Ultimate Heat Sink) to Fermi 2 safety systems.

23

24 **Q72. Does the safety-related service water piping have a nuclear safety function?**



Line  
No.

1 A72. Yes. As explained in Chapter 9 of the Fermi 2 USFAR, the ultimate heat sink  
2 consists of a single highly reliable water source with fully redundant cooling  
3 towers, pumps, and conduits capable of providing sufficient cooling for 7 days to  
4 permit safe shutdown and cooldown of the nuclear unit in the event of a design-  
5 basis accident.

6

7 **Q73. How does replacement of the underground safety-related service water piping**  
8 **provide a benefit to the community?**

9 A73. Replacement of the underground safety-related service water piping provided the  
10 Fermi 2 Power Plant with restored margins against risk of safety-related service  
11 water piping leaks which, in turn, results in potential incremental carbon-free  
12 generation for the community.

13

14 **Q74. Can you discuss the expenditures and rationale for the License Renewal**  
15 **Implementation (LRI) project shown on line 5 of Exhibit A-12, Schedule B5.3,**  
16 **page 4?**

17 A74. The License Renewal Implementation (LRI) capital project activities are DTE  
18 Electric's NRC renewed license commitments of first-time and one-time plant  
19 equipment inspections required to operate during its Period of Extended Operations  
20 which begins in 2025. The LPR is projected to complete in 2025, and the project  
21 has a projected in-service date of 2025 (along with the Fermi 2 License Renewal  
22 project held in Future Use). The License Renewal Implementation (LRI) project  
23 capital expenditures for the historical test year, projected bridge forecast period and  
24 projected test period are \$7.7 million, \$6.3 million, and \$0.0 million respectively  
25 and do not extend beyond the projected test period.

Line  
No.

1 To ensure safe operations during a plant's Period of Extended Operation, the NRC  
2 mandates programs to monitor and intrusively inspect passive plant systems that  
3 may be impacted by plant age; the Fermi 2 LRI project coordinates and conducts  
4 the first-time and one-time inspections associated with this new and regulatorily-  
5 required monitoring and inspection regime; failure to complete these first-time and  
6 one-time inspections would result in NRC violations and possible suspension of  
7 Fermi 2's renewed operating license.

8

9 **Q75. What is the purpose of the LRI project?**

10 A75. The Fermi 2 LRI is a component of the Fermi 2 Aging Management and Activities  
11 program which is more fully described in Appendix B of the Fermi 2 USFAR.

12

13 **Q76. Does the LRI have a nuclear safety function?**

14 A76. Yes. As explained in Appendix B of the Fermi 2 USFAR, Fermi 2's aging  
15 management programs provide reasonable assurance that components and  
16 equipment within the scope of license renewal (and LRI project) will continue to  
17 perform their intended functions consistent with the current Fermi 2 licensing basis  
18 for the period of extended operation.

19

20 **Q77. How does the completion of the Fermi 2 LRI project provide a benefit to the**  
21 **community?**

22 A77. Completion of the Fermi 2 LRI activities allow Fermi 2 to operate Fermi 2 for the  
23 period of extended operation which, in turn, provides the community with Fermi  
24 2's carbon-free generation for twenty years through March 2045.

Line  
No.

1   **Q78. Can you discuss the expenditures and rationale for the Feed Water Heaters**  
2       **Replacements project shown on line 6 of Exhibit A-12, Schedule B5.3, page 4?**

3   A78. The Feed Water Heater (FWH) replacements project as depicted on line 6 replaces  
4       six Fermi 2 feed water heaters. This replacement project is expected to complete  
5       during RF23 and the project has a projected in-service year of 2026. The FWH  
6       replacements capital expenditures for the historical test year, projected bridge  
7       forecast period and projected test period are \$7.0 million, \$16.0 million and \$33.1  
8       million respectively.

9  
10       The FWH replacement project replaces six feed water heaters (#3N (north), #3S  
11       (south), #4N, #4S, #5N and #5S) which are original plant equipment and are at the  
12       end of their service life; this project also serves to improve operational margins and  
13       reduce radiological dose rates within the plant.

14  
15   **Q79. Are there logistical complexities associated with the replacement of the feed**  
16       **water heaters?**

17   A79. These feed water heaters are quite large (i.e. approximately the size of a semi-trailer  
18       and weighing between 80,000 and 130,000 pounds each) and located in enclosed  
19       rooms within the Fermi 2 Turbine Building, surrounded by pipes. To get these feed  
20       water heaters into the Turbine Building requires disassembly of the east wall of the  
21       Turbine Building and relocation of structures within the building. Additionally,  
22       each of the piping interferences must be removed from the feed water heater rooms  
23       to allow the existing feed water heaters enough space to be removed and new feed  
24       water heaters moved into place; the interference piping must then be restored along  
25       with the Turbine Building wall prior to unit startup.

Line  
No.

1    **Q80. What is the purpose of the Fermi 2 feed water heaters?**

2    A80. The Fermi 2 feed water heaters are components within the Fermi 2 feed water  
3       system which is more fully described in Fermi 2 USFAR Chapter 10 Steam and  
4       Power Conversion. The Fermi 2 feed water system returns reactor water to the  
5       Fermi 2 reactor from the Fermi 2 main unit condenser.

6  
7       The Fermi 2 feed water system uses six stages of feed water heaters to properly  
8       condition reactor water as it returns to the reactor. The first- (#1) and second-stage  
9       (#2) low-pressure feed water heaters are identically arranged in three parallel  
10      streams. The third (#3), fourth (#4), fifth (#5), and sixth (#6) stages of feed water  
11      heating are arranged in two parallel (north and south) streams.

12

13   **Q81. Do the FWHs have a nuclear safety purpose?**

14   A81. No. As described in the Fermi 2 USFAR Chapter 10, the feed water system is not  
15      required to cause or support the safe shutdown of the reactor or nuclear supply  
16      steam system (NSSS) or to perform in the operation of NSSS safety features. In  
17      certain situations, the system can also make use of its multistream arrangement to  
18      operate at reduced powers if a system component such as a feed water pump or  
19      motor is removed from service; therefore, reliability of the feed water system is  
20      primarily a function of electrical grid system operating requirements.

21

22   **Q82. How does replacement of the FWHs provide a benefit to the community?**

23   A82. Replacement of the FWHs will restore operating margins to the Fermi 2 feed water  
24      system which, in turn, results in a potential incremental carbon-free generation for  
25      the community. Replacement of the FWHs will also eliminate a source of radiation

Line  
No.

1 activity within the Fermi 2 Power Plant which will allow workers at the plant to  
2 receive potentially incrementally less radiation dose.

3

4 **Q83. Can you discuss the expenditures and rationale for the Radiation Monitors**  
5 **project shown on line 7 of Exhibit A-12, Schedule B5.3, page 4?**

6 A83. The radiation monitors project as depicted on line 7 replaces the radiation monitor  
7 computer and plant radiation monitors. This replacement project is projected to  
8 complete in 2025 and has a projected in-service year of 2025. The radiation  
9 monitors capital expenditures for the historical test year, projected bridge forecast  
10 period and projected test period are \$4.7 million, \$15.6 million and \$0.0 million  
11 respectively.

12

13 The Radiation Monitors project replaces Fermi 2's radiation monitor computer  
14 referred to as "SS1," as well as the plant's SPING (which detects particulate, iodine  
15 and noble gases) and AXM (the accident range effluent monitor) radiation monitors  
16 which are at end of life; these component replacements of the radiation monitor  
17 system are necessary to address aging and obsolescence, reduce the resource and  
18 dose impact of compensatory sampling, and improve regulatory margins;  
19 unexpected or unrecoverable loss of this radiation monitor system could result in  
20 NRC enforcement action.

21

22 **Q84. What is the purpose of the Fermi 2 Radiation Monitoring System?**

23 A84. The Fermi 2 radiation monitoring systems are more fully described in the Fermi 2  
24 USFAR Chapter 11 Radioactive Waste Management. Together with the SS1  
25 computer, the radiation monitoring system monitors and analyzes the plant's

Line  
No.

1 gaseous effluents to affirm the plant's radiation levels remain within proper  
2 specification. This radiation monitor system is credited in Fermi 2's Emergency  
3 Response Plan due to its capacity to monitor and analyze potential radioactive  
4 releases and thus directly impacts recommendations provided to the state for  
5 instituting emergency actions for the public in the event of an emergency.

6

7 **Q85. Does the Fermi 2 Radiation Monitoring System have a nuclear safety**  
8 **function?**

9 A85. Yes. As described in the Fermi 2 USFAR Chapter 11, portions of the radiation  
10 monitoring system are required to measure and record radioactivity levels, to alarm  
11 on high radioactivity levels, and to control, as required, the release of radioactive  
12 liquids, gases, and particulates produced during operation of the plant. The  
13 radiation monitoring system also aids in protection of the community and plant  
14 personnel from exposure to radiation or radioactive materials in excess of those  
15 allowed by the applicable regulations of governmental agencies.

16

17 **Q86. How does the replacement of the Fermi 2 radiation monitoring system provide**  
18 **a benefit to the community?**

19 A86. Replacement of the Fermi 2 radiation monitoring systems improves system  
20 reliability margins and supports safe operation of the Fermi 2 Power Plant. In the  
21 unlikely event of a radioactivity release, the radiation monitoring systems aid DTE  
22 Electric in protecting the community from radiation or radioactive materials in  
23 excess of those allowed by regulations.

Line  
No.

1   **Q87. Can you discuss the expenditures and rationale for the Fire Header**  
2       **Restoration project shown on line 8 of Exhibit A-12, Schedule B5.3, page 4?**

3   A87. The Fire Header Restoration project replaces portions of the Fermi 2 fire header  
4       piping. The Fire Header Restoration project capital expenditures for the historical  
5       test year, projected bridge forecast period and projected test period are \$4.1 million,  
6       \$0.0 million, and \$0.0 million respectively. This replacement project completed in  
7       2023 and was placed in-service in 2023.

8

9       The Fermi 2 fire header pipe was original to plant construction and at end of life;  
10      these replacements addressed natural aging of the Fermi 2 fire header piping and  
11      restored margins to Fermi 2's fire header water carrying capacity.

12

13   **Q88. What is the purpose of the Fermi 2 fire header?**

14   A88. The Fermi 2 fire header is a component of the Fermi 2 fire detection and protection  
15       system which is more fully described in the Fermi 2 USFAR Chapter 9 Auxiliary  
16       Systems. The purpose of Fermi 2 fire header is to distribute firefighting water from  
17       the normal or alternate sources of water to the scene of a postulated fire.

18

19       The Fermi 2 fire header piping is approximately 5000' of underground pipe that  
20       routes around Fermi 2 to distribute fire-fighting water to fire hydrants and trunk  
21       lines.

22

23   **Q89. Does the Fermi 2 fire header have a nuclear safety function?**

24   A89. Yes. As explained in the Fermi 2 USFAR Chapter 9, the Fermi 2 fire header is  
25       important to safety and protects from fire that equipment necessary to ensure the

Line  
No.

1 safe shutdown of the reactor; with fire being one of the most consequential events  
2 at a nuclear power plant, unplanned or unrecoverable loss of the fire header piping  
3 would challenge plant operator's ability to safely operate the Fermi 2 plant.

4

5 **Q90. How does replacement of the Fermi 2 fire header benefit the community?**

6 A90. The fire header pipe is original to plant construction and is approaching fifty years  
7 of in-service time. As a fire header, the piping is exposed to raw lake water which  
8 degrades the interior surfaces of the pipe, causing leaks and loss of water pressure.  
9 The existing fire header pipe would not support safe and reliable operations through  
10 Fermi 2's current operating life ending in 2045. DTE Electric is taking the  
11 reasonable and prudent approach to replace the fire header pipe over time and in  
12 stages based on priorities derived from inspection and testing; this also allows for  
13 minimal fire header outage time, minimal operational compensatory measures to  
14 protect the plant while replacement is occurring, and supports safe Fermi 2  
15 operations through 2045.

16

17 **Q91. Can you discuss the expenditures and rationale for the Boraflex Fuel Storage**  
18 **Racks project shown on line 9 of Exhibit A-12, Schedule B5.3, page 4?**

19 A91. The Boraflex fuel storage racks project installs new neutron-absorbing materials  
20 into the Fermi 2 Boraflex fuel storage racks. The Boraflex Fuel Storage Rack  
21 project completed in 2025 and was placed in-service in 2025. The Boraflex Fuel  
22 Storage Racks capital expenditures for the historical test year, projected bridge  
23 forecast period and projected test period are \$2.9 million, \$4.3 million and \$0.0  
24 million respectively.



Line  
No.

1 The Boraflex fuel storage racks are at end-of-life; the installation of new neutron-  
2 absorbing material into the Boraflex fuel storage racks address an NRC commitment  
3 tied to Fermi 2's license renewal and is necessary to restore safety margins for the  
4 storage of the spent fuel through the end of the operating license in 2045.

5

6 **Q92. What is the purpose of the Fermi 2 Boraflex fuel storage racks?**

7 A92. The Boraflex fuel storage racks are a component of the Fermi 2 Spent Fuel Storage  
8 which is more fully described in the Fermi 2 USFAR Chapter 9 Auxiliary Systems.  
9 The purpose of Fermi 2 Boraflex fuel storage racks is to safely store spent nuclear  
10 fuel in the Fermi 2 Spent Fuel Storage Pool until such time as the spent nuclear fuel  
11 can be safely transferred to dry storage; the Boraflex fuel storage racks also safely  
12 stage new nuclear fuel for the limited time between new fuel receipt and insertion  
13 into the Fermi 2 reactor core.

14

15 Spent fuel storage space is provided to accommodate 3590 nuclear fuel assemblies,  
16 of which, approximately 2900 are Boraflex fuel storage racks which are receiving  
17 the new neutron-absorbing material.

18

19 **Q93. Do the Boraflex Spent Fuel Storage Racks have a nuclear safety function?**

20 A93. Yes. As explained in the Fermi 2 USFAR Chapter 9, the neutron-absorbing material  
21 within the spent fuel storage racks prevents spent nuclear fuel from sustaining a  
22 critical nuclear reaction in all normal and abnormal operating conditions.

23

24 **Q94. How does replacement of the Boraflex Spent Fuel Storage Racks benefit the**  
25 **customer?**

Line  
No.

1 A94. The existing Boraflex Spent Fuel Storage racks are original plant equipment and  
2 the embedded neutron-absorbing material has depleted. Insertion of new neutron-  
3 absorbing material into the Boraflex Spent Fuel Storage Racks enables Fermi 2 to  
4 continue to safely store spent nuclear fuel within its Spent Fuel Pool to at least  
5 2045.

6

7 **Q95. Can you discuss the expenditures and rationale for the Drywell Moisture**  
8 **Barrier Replacement project shown on line 14 of Exhibit A-12, Schedule B5.3,**  
9 **page 4?**

10 A95. The drywell moisture barrier replacement project replaced the moisture barrier  
11 system located between the drywell and the reactor pressure vessel. This  
12 replacement project is complete and the moisture barrier system was placed in-  
13 service in 2024. The drywell moisture barrier replacement capital expenditures for  
14 the historical test year, projected bridge forecast period and projected test period  
15 are \$0.0 million, \$3.5 million and \$0.0 million respectively.

16

17 The drywell moisture barrier project was original to plant construction and at end-  
18 of-life; replacement of the moisture barrier restored safety margins to prevent  
19 corrosion of the reactor pressure vessel through the end of the operating license in  
20 2045.

21

22 **Q96. What is the purpose of the drywell moisture barrier?**

23 A96. The drywell moisture barrier is a component of the Fermi 2 primary containment  
24 which is more fully described in the Fermi 2 USFAR Chapter 6 Engineered Safety  
25 Features. The purpose of Fermi 2 drywell moisture barrier is to prevent intrusion of

Line  
No.

1 moisture in the gap between the concrete drywell floor and the carbon steel drywell  
2 shell to prevent corrosion of the primary containment from occurring.

3

4 **Q97. Does the drywell moisture barrier have a nuclear safety function?**

5 A97. Yes. As discussed in the Fermi 2 USFAR Chapter 6, the Fermi 2 primary  
6 containment has many nuclear safety functions – notably, primary containment is  
7 designed to contain and minimize release of radioactive material during a  
8 postulated accident. The drywell moisture barrier has a linear length of  
9 approximately 155 feet and prevents intrusion of moisture into inaccessible areas  
10 of the primary containment which, in turn, prevents corrosion of the primary  
11 containment.

12

13 **Q98. How does replacement of the drywell moisture barrier benefit the community?**

14 A98. Replacement of the drywell moisture barrier protects the Fermi 2 primary  
15 containment from moisture-induced corrosion and supports safe operation of the  
16 Fermi 2 Power Plant through at least 2045.

17

18 **Q99. Can you discuss the expenditures and rationale for the Turbine Controls**  
19 **Replacements project shown on line 15 of Exhibit A-12, Schedule B5.3, page**  
20 **4?**

21 A99. The turbine controls replacement project replaces the main unit turbine controls.  
22 This replacement project is projected to complete in RF25 (spring 2030) and has a  
23 projected in-service year of 2030. The turbine controls replacement capital  
24 expenditures for the historical test year, projected bridge forecast period and  
25 projected test period are \$0.0 million, \$2.2 million and \$4.4 million respectively.

Line  
No.

1 The turbine controls are at end of life; replacement of the turbine controls addresses  
2 obsolescence.

3

4 **Q100. What is the purpose of the turbine controls?**

5 A100. The turbine controls are a component of the Fermi 2 power conversion systems  
6 which is more fully described in Fermi 2's USFAR Chapter 10 Steam and Power  
7 Conversion. The purpose of the Fermi 2 turbine controls is to regulate turbine speed  
8 and protect the Fermi 2 turbine set and main unit generator.

9

10 **Q101. Do the turbine controls have a nuclear safety function?**

11 A101. No. As explained in Chapter 10 of the Fermi 2 USFAR, none of the components of  
12 the power conversion systems are required to operate to ensure a safe reactor  
13 shutdown. Fermi 2's reactor safety systems are designed to protect the reactor under  
14 all conditions which includes complete isolation from the power conversion  
15 systems; therefore, reliability of power conversion systems, with the exception for  
16 control of radioactivity, is primarily a function of electrical grid system operating  
17 requirements.

18

19 **Q102. How does completion of the turbine controls replacements project benefit the**  
20 **community?**

21 A102. Replacement of the turbine controls will provide Fermi 2 Power Plant with  
22 improved margins against risk of damage to the main turbine and main unit  
23 generator which, in turn, results in potential incremental carbon-free generation for  
24 the community.

Line  
No.

1    **Q103. Can you discuss the expenditures and rationale for the Fire Detection System**  
2           **Replacement project shown on line 18 of Exhibit A-12, Schedule B5.3, page 4?**

3    A103. The fire detection system replacement project replaces the Fermi 2 Turbine  
4           Building fire detection system. The fire detection system replacement project is  
5           projected to complete and to be placed in-service in 2025. The fire detection system  
6           replacement project capital expenditures for the historical test year, projected  
7           bridge forecast period and projected test period are \$0.0 million, \$5.6 million, and  
8           \$0.0 million respectively.

9  
10          The Fermi 2 fire detection system is original to plant construction and at end of life;  
11          replacement of the Turbine Building fire detection systems also addresses  
12          obsolescence of the Fermi 2 fire detection system.

13  
14    **Q104. What is the purpose of the Fermi 2 fire detection system?**

15    A104. The Fermi 2 detection system is a component of the Fermi 2 fire detection and  
16          protection system which is more fully described in the Fermi 2 USFAR Chapter 9  
17          Auxiliary Systems. The Fermi 2 fire detection system consists of detection and  
18          annunciation systems. The purpose of the Fermi 2 fire detection system is to detect  
19          fire and signal fire alarms, and is designed to supplement Fermi 2's other fire  
20          safeguards such as design, procedures and behaviors; with fire being one of the  
21          most consequential events at a nuclear power plant, unplanned or unrecoverable  
22          loss of the fire detection system would challenge plant operator's ability to safely  
23          operate the Fermi 2 plant.

24  
25    **Q105. Does the Fermi 2 fire detection system have a nuclear safety function?**

Line  
No.

1 A105. Yes. As explained in the Fermi 2 USFAR Chapter 9, the Fermi 2 fire detection is  
2 important to safety and protects from fire that equipment necessary to ensure the  
3 safe shutdown of the reactor; with fire being one of the most consequential events  
4 at a nuclear power plant, unplanned or unrecoverable loss of the fire detection  
5 capabilities would challenge plant operators' ability to safely operate the Fermi 2  
6 plant.

7

8 **Q106. Can you discuss the expenditures and rationale for the Reactor Recirculation**  
9 **Motor-Generator (RRMG) Replacement project shown on line 22 of Exhibit**  
10 **A-12, Schedule B5.3, page 4?**

11 A106. The Reactor Recirculation Motor-Generator (RRMG) replacement project replaces  
12 the Fermi 2 RRMGs. This replacement project is projected to complete in RF24  
13 (spring 2028) and to be placed in-service in year 2028. The Reactor Recirculation  
14 Motor-Generator (RRMG) replacement project capital expenditures for the  
15 historical test year, projected bridge forecast period and projected test period are  
16 \$0.0 million, \$7.2 million, and \$17.8 million respectively.

17

18 The RRMG motor rotors, in particular, have been in service since plant start up in  
19 the 1980s and have increasing risk of developing shorts as in-service time extends  
20 past 30 years; this project will also decrease house electrical loads (i.e. make  
21 additional electrical generation available for transmission to the grid).

22

23 **Q107. What is the purpose of the RRMG sets?**

24 A107. The RRMG sets are a component of the Fermi 2 Reactor Recirculation System  
25 (RRS) which is more fully described in the Fermi 2 USFAR Chapter 5 Reactor

Line  
No.

1 Coolant System and Connected Systems. The purpose of the Fermi 2 RRMG sets  
2 is to provide variable power to the Fermi Reactor Recirculation System (RRS)  
3 pump motors, one RRMG set controls, and one RRS pump motor.

4  
5 The RRS consists of the two RRS pump loops external to the reactor pressure vessel.  
6 Each external loop contains one variable-speed motor-driven RRS pump, two  
7 motor-operated gate valves, and a motor-generator set to control RRS pump speed.  
8 The existing Fermi 2 RRMGs consist of an RRMG motor, fluid coupler, oil system,  
9 generator and scoop tube positioner.

10

11 **Q108. Do the RRMG sets have a nuclear safety function?**

12 A108. Yes. As described in USFAR Chapter 5 the RRS provides sufficient flow to ensure  
13 adequate heat removal from the core.

14

15 **Q109. How does completion of the Reactor Recirculation Motor-Generator (RRMG)**  
16 **replacement benefit the community?**

17 A109. Replacement of the RRMG sets with variable speed drives will improve operating  
18 margins and reduce operator burdens. These improved margins against the risk of  
19 loss of RRS, in turn, results in potential incremental carbon-free generation for the  
20 community.

21

22 **Q110. Can you discuss the expenditures and rationale for the General Service Water**  
23 **(GSW) piping replacements project shown on line 23 of Exhibit A-12, Schedule**  
24 **B5.3, page 4?**

Line  
No.

1 A110. The General Service Water (GSW) piping replacement project replaces  
2 approximately 300 feet of 24-inch diameter GSW piping using an *in-situ*  
3 replacement technique; the project will also replace two 24-inch GSW isolation  
4 valves. This replacement project is projected to complete in 2026 and has a  
5 projected in-service year of 2026. The GSW piping replacements project capital  
6 expenditures for the historical test year, projected bridge forecast period and  
7 projected test period are \$0.0 million, \$1.7 million and \$3.5 million respectively.

8

9 The GSW piping is original to the plant and portions of the pipe have experienced  
10 through-wall leaks – without remediation, GSW piping leaks could cause wetting  
11 of plant equipment or loss of GSW, which would result in a plant shutdown to  
12 remediate.

13

14 **Q111. What is the purpose of the General Service Water (GSW) Piping?**

15 A111. The Fermi 2 GSW piping are a component of the Fermi 2 General Service Water  
16 system which is more fully described in Fermi 2's USFAR Chapter 9 Auxiliary  
17 Systems. The Fermi 2 GSW system provides cooling water (directly drawn from  
18 Lake Erie) to remove various plant heat loads during normal operation; unplanned  
19 or unrecoverable loss of the GSW would challenge the plant operator's ability to  
20 safely operate the Fermi 2 plant.

21

22 The GSW piping trunk is 24-inch diameter metal piping that distributes strained  
23 biocide-treated Lake Erie water to the plant heat exchanger equipment for use in  
24 heat removal and other plant systems; GSW water is discharged into the Fermi 2  
25 Circulating Water Pond.



Line  
No.

1 **Q112. Does the asset have a nuclear safety function?**

2 A112. No. As explained in Chapter 9 of the Fermi 2 USFAR, none of the components of  
3 the GSW system are required to be operable to effect safe shutdown of the Fermi 2  
4 Power Plant; therefore, reliability of the GSW system is primarily a function of  
5 electrical grid system operating requirements.

6

7 **Q113. How does completion of the GSW piping replacements project benefit the**  
8 **community?**

9 A113. Replacement of the GSW piping provides the Fermi 2 Power Plant with improved  
10 margins against risk of loss of GSW which, in turn, results in potential incremental  
11 carbon-free generation for the community.

12

13 **Q114. Can you discuss the expenditures and rationale for the Circulating Water**  
14 **(CW) Traveling Screens project shown on line 25 of Exhibit A-12, Schedule**  
15 **B5.3, page 4?**

16 A114. The Circulating Water (CW) traveling screens project replaces the stationary debris  
17 screens at the Circulating Water Pump House (CWPH) intake structure with  
18 traveling screens. This replacement project is projected to complete in 2027 and  
19 has a projected in-service year of 2027. The CW traveling screens project capital  
20 expenditures for the historical test year, projected bridge forecast period and  
21 projected test period are \$0.0 million, \$0.1 million and \$6.2 million respectively.

22

23 **Q115. What is the purpose of the CW traveling screens?**

24 A115. The CW screens are a component of the Fermi 2 Circulating Water (CW) system  
25 which is more fully described in the Fermi 2 USFAR Chapter 10 Steam and Power

Line  
No.

1 Conversion Systems. The purpose of Fermi 2 CW system is to transport rejected  
2 cycle heat from the main unit condenser to the two parallel natural draft cooling  
3 towers. The CW screens filter debris at CWPB intake as CW cycles from the  
4 cooling towers towards the main unit condenser.

5

6 **Q116. Does the asset have a nuclear safety function?**

7 A116. As described in the Fermi 2 USFAR Chapter 10, the CW system is not required to  
8 cause or support the safe shutdown of the reactor or nuclear supply steam system  
9 (NSSS) or to perform in the operation of NSSS safety features; therefore, reliability  
10 of the feed water system is primarily a function of electrical grid system operating  
11 requirements.

12

13 **Q117. How does completion of the CW traveling screens project benefit the**  
14 **community?**

15 A117. Replacement of the CW stationary screens with traveling screens will improve the  
16 margin of the CWPB intake filtering and will incrementally improve the reliability  
17 of the main unit condenser which, in turn, may incrementally increase the amount  
18 of carbon-free electricity generation.

19

20 **Q118. Can you discuss the expenditures and rationale for the Sanitary System**  
21 **replacement project shown on line 26 of Exhibit A-12, Schedule B5.3, page 4?**

22 A118. The Sanitary System replacement project replaces the antiquated sanitary  
23 wastewater disposal system with a more modern two pump system capable of safely  
24 disposing of Fermi 2's sanitary wastewater. This replacement project is projected  
25 to complete in 2028 and has a projected in-service year of 2028. The Sanitary

Line  
No.

1 System replacement project capital expenditures for the historical test year,  
2 projected bridge forecast period and projected test period are \$0.0 million, \$0.0  
3 million, and \$2.8 million respectively and addresses aging and undersized piping,  
4 and supports the necessary replacement of the Fermi sanitary system. The sanitary  
5 wastewater system is designed to dispose of nonradioactive plant sewage liquid  
6 waste in accordance with state and local regulations and consists of piping and a  
7 pumping station. The current pump house, which was originally built to support  
8 Fermi 1 which commenced construction in the late 1950's, consists of a septic tank,  
9 settling Tank, wet well, and pumps to transfer sewage around the facility and to  
10 discharge out the forced main; however, the pumps are not designed to pump solid  
11 waste and the concrete structure is in need of repair or replacement - due to the  
12 location, a failure of the structure risks a release into Lake Erie.

13

14 **Q119. Do any of the projects listed in Exhibit A-12, Schedule B5.3, pages 2-4 contain**  
15 **contingency amounts?**

16 A119. No. The capital expenditures as shown in Exhibit A-12, Schedule B5.3, pages 2-4  
17 do not include contingencies. The capital expenditures shown in Exhibit A-12,  
18 Schedule B5.3, pages 2-4 are good faith estimates (without contingencies) based  
19 on relevant data available using reasonable and prudent forecasting methods.

20

21 **Q120. Does the absence of contingency amounts in Exhibit A-12, Schedule B5.3,**  
22 **pages 2-4 impact individual project expenditure variances from DTE Electric**  
23 **rate case to rate case?**

24 A120. Certainly. The need for and use of contingency amounts at the individual project  
25 level and at the portfolio level is well understood in project management and

Line  
No.

1 portfolio management. Because DTE Electric's Nuclear Generation projects don't  
2 include contingencies, some known scope with highly uncertain costs have  
3 projected expenditures excluded from exhibits (such as the Security Computer  
4 Replacement project) until such time as the expenditures are capable of being  
5 identified with reasonable specificity to include in the exhibit; therefore, projects  
6 expenditures will necessarily change as less defined scope and previously excluded  
7 expenditures transition into better identified and included expenditures. This is a  
8 reasonable and prudent approach in light of the expectation to exclude contingency  
9 amounts from DTE Electric's rate case exhibits and subsequent revenue  
10 requirements.

11

12 **Q121. How does the Nuclear Generation organization manage its capital**  
13 **expenditures without contingencies?**

14 A121. Nuclear Generation manages total capital expenditures for the period and expects  
15 that capital expenditures in total will be incurred as projected. In general, Nuclear  
16 Generation maintains a prioritized list of projects such that as project forecasts are  
17 over or under expected amounts, Nuclear Generation uses this prioritized list  
18 consistent with the key principles I described earlier to manage the Nuclear  
19 Generation portfolio of projects.

20

21 **Nuclear Fuel Capital Expenditures**

22 **Q122. Can you explain Total Nuclear Fuel summarized on line 10 of Exhibit A-12,**  
23 **Schedule B5.3, page 1?**

Line  
No.

1 A122. Yes. Total Nuclear Fuel includes those capital expenditures for the various  
2 components of the nuclear fuel cycle: (1) Uranium, (2) Conversion, (3) Enrichment  
3 and (4) Fabrication.

4  
5 Uranium refers to the costs associated with mining and milling uranium. Natural  
6 uranium is obtained from the exploration and mining of uranium ore. Milling is the  
7 mechanical and chemical process of extracting uranium from the mined ore in the  
8 form of  $U_3O_8$ , commonly referred to as yellowcake. The  $U_3O_8$  is the feed material  
9 for the conversion process.

10  
11 Conversion refers to the costs associated with chemically converting  $U_3O_8$  into  
12  $UF_6$ , uranium hexafluoride. The  $UF_6$  is the gaseous compound used as a feed in  
13 the enrichment process.

14  
15 Enrichment refers to the costs to enrich the uranium from a natural 0.7%  $U^{235}$   
16 content to a 4% to 5%  $U^{235}$  content required for light water reactor fuel. The  
17 enriched  $UF_6$  is used as a feed in the fabrication process.

18  
19 Fabrication refers to the chemical conversion of the enriched  $UF_6$  to  $UO_2$  (uranium  
20 dioxide) powder which is then pressed and sintered into hard ceramic fuel pellets  
21 that are loaded into long, narrow zirconium alloy tubes called fuel rods; fuel rods  
22 are then assembled into fuel bundles using spacers and end fittings to hold the fuel  
23 rods together. The Fermi 2 reactor core requires 764 of these fuel bundles to  
24 operate.

Line  
No.

1 The amount of fuel purchased is determined by the design of the fuel and by the  
2 expected generation during the life of the fuel. Nuclear fuel capital expenditures  
3 were developed on the basis that Fermi 2 transitioned from its 18-month operating  
4 cycle to the 24-month operating cycle following RF21 in winter/spring of 2022.

5

6 The accounting of nuclear fuel expenditures completes with the delivery of the  
7 fabricated nuclear fuel to the Fermi 2 Power Plant. Expenditures arising from on-  
8 site activities such as new fuel receipt, new fuel storage and insertion of the new  
9 nuclear fuel into the reactor core are recorded in the appropriate expense account.

10

11 **Q123. Can you explain the Total Nuclear Fuel expenditures as shown on Exhibit A-**  
12 **12, Schedule B5.3, page 1, line 10?**

13 A123. Yes. The Total Nuclear Fuel capital expenditures for the historical test year,  
14 projected bridge forecast period and projected test period are \$110.0 million,  
15 \$134.4 million and \$0.2 million respectively and are consistent with Fermi 2's  
16 projections in the Company's 2025 PSCR Plan in Case No. U-21594.

17

18 **Q124. Can you explain why Total Nuclear Fuel expenditures vary from year-to-year?**

19 A124. Yes. Total Nuclear Fuel expenditures vary from year-to-year because Fermi 2  
20 operates on a 24-month fuel cycle and fuel expenditures occur at relatively fixed  
21 points in time relative to that 24-month fuel cycle (most nuclear fuel capital  
22 expenditures occur approximately six months prior to a refueling outage);  
23 therefore, Total Nuclear Fuel capital expenditures can be expected to vary each year  
24 but follow a repeating two-year pattern with more expenditures projected in the odd  
25 years and lesser expenditures projected in the even years.

Line  
No.

1 **Q125. What is the status of DTE Electric's uranium fuel cycle contracts?**

2 A125. The Company has secured the necessary uranium, conversion, enrichment and  
3 fabrication through the projected test period ending December 31, 2026, which has  
4 helped the Company mitigate the general increase in uranium pricing over the past  
5 approximately three years.

6

7 **Q126. What is the state of the uranium fuel cycle markets?**

8 A126. Though DTE Electric does not use uranium or other uranium fuel cycle services of  
9 Russian origin, the Russian military conflict with Ukraine has stressed the global  
10 uranium fuel cycle supply chain for the US industry and has caused pricing  
11 pressures throughout the supply chain because Russia is a significant country of  
12 origin of uranium and the primary country of origin for enrichment services  
13 purchased by U.S. nuclear plant owners and operators. The Prohibiting Russian  
14 Uranium Imports Act signed into law in 2024 may further stress these fuel cycle  
15 supply chains as US nuclear power plant owners and operators move away from  
16 uranium and uranium fuel cycle services of Russian origin and compete for the  
17 limited uranium and uranium fuel cycle services of non-Russian origin.

18

19 The U.S. Department of Energy's Energy Information Agency (EIA) annually  
20 surveys and reports weighted-average price of uranium purchased by owners and  
21 operators of U.S. civil commercial nuclear power plants. EIA's survey reports the  
22 2021, 2022 and 2023 weighted-average price of uranium (expressed dollars per  
23 pound U<sub>3</sub>O<sub>8</sub> equivalent) as \$34.71, \$38.81 and \$42.42 respectively (Table S1b).  
24 EIA also reports that uranium futures contracts signed in 2023 had a weighted-  
25 average price of uranium at \$61.93 (Table 8). DTE Electric Witness Wines Exhibit

Line  
No.

1 A-17 in Case No. U-21594 depicts DTE Electric's projected PSCR annual fuel  
2 expenses increasing from \$6.59/MWH in 2025 to \$9.48/MWH in 2029 as the newer,  
3 more expensive uranium is loaded into the Fermi 2 reactor and consumed.

4

5 **Q127. How would you characterize the level of expenditures for Fermi 2's Total**  
6 **Nuclear Fuel?**

7 A127. Fermi 2's fuel expenditures are reasonable and prudent. The projected expenditures  
8 are consistent with the existing DTE Electric contracts, and the quantity of uranium,  
9 enrichment and nuclear fuel assemblies required to be loaded in RF23 for the Fermi  
10 2 Cycle 24.

11

12 **AFUDC Forecast**

13 **Q128. Can you explain the Allowance for Funds Used During Construction (AFUDC)**  
14 **as shown in Exhibit A-12, Schedule B5.3, page 5?**

15 A128. Nuclear Generation capital expenditures include an Allowance for Funds Used  
16 During Construction (AFUDC) for eligible projects that are in Construction Work  
17 in Progress (CWIP); eligible projects are those projects greater than \$50,000 and  
18 lasting more than six months. The actual historical period Total AFUDC – Nuclear  
19 Production Plant was \$12.6 million as shown in Exhibit A-12, Schedule B5.3, page  
20 5, line 29, column (b). The forecasted Total AFUDC – Nuclear Production Plant  
21 for the projected test period is \$8.6 million as shown in Exhibit A-12, Schedule  
22 B5.3, page 5, line 29, column (c).

23

24 **Q129. How did you forecast the AFUDC as shown in Exhibit A-12, Schedule B5.3,**  
25 **page 5?**



Line  
No.

1 A129. The Nuclear Production Plant – Routine Expenditures AFUDC forecast uses a  
2 historical trend to estimate AFUDC as the mix of eligible projects is fairly  
3 consistent year-to-year. The Nuclear Production Plant – Project Specific AFUDC  
4 forecast explicitly calculates AFUDC for eligible projects using project-specific  
5 CWIP balances multiplied by the AFUDC rate where the AFUDC rate is the  
6 authorized cost of capital rate of 5.561% consistent with the December 1, 2025  
7 Order in Case No. U-21534.

8

9 **Removal Costs, Plant in Service and CWIP Forecast**

10 **Q130. What is provided on the schedule entitled Removal Costs, Plant in Service and**  
11 **CWIP schedule on Exhibit A-12, Schedule B5.3, page 6?**

12 A130. This schedule provides a breakdown of plant activities which are used by Witness  
13 Uzenski to forecast Plant in Service, Accumulated Depreciation and CWIP on the  
14 projected balance sheet.

15

16 Capital expenditures consistent with page 1 are summarized in columns (c) through  
17 (f). Routine and Non-Routine projects are sub-totaled on Lines 1 and 28  
18 respectively, while Fermi 2 License Renewal has been identified separately on line  
19 30 because this is recorded to Plant Held for Future Use. Column (b) includes a  
20 corresponding in-service assumption: “Annual” is indicated for both routine and  
21 non-routine spend because these projects are generally unitized within the year of  
22 spend.

23

24 Column (g) includes an estimated percentage of removal costs that are included  
25 within the capital expenditures. Removal costs, as discussed by Witness Uzenski,

Line  
No.

1 are charged to Accumulated Depreciation rather than Plant/ CWIP and are therefore  
2 not depreciable. Removal cost of 15% based on the historical trend of removals as  
3 a component of capital expenditures is applied to Routine and Non-Routine project  
4 expenditures.

5  
6 Column (h) through (j) reflect calculated removal costs based on projected Capital  
7 Expenditures in columns (d) through (f) multiplied by the removal cost percentage  
8 in column (g). The remaining Capital Expenditures will appear in Plant in Service  
9 columns (k) through (m) since the in-service assumption is "Annual." The CWIP  
10 columns (n) through (p) show CWIP activity.

11

12 **2023 – 2026 Capital Projects Summary**

13 **Q131. What is your opinion regarding the reasonableness of the forecasted capital**  
14 **expenditures for Nuclear Generation?**

15 A131. I believe the forecasted capital expenditures for Nuclear Generation are reasonable  
16 and prudent. I believe the forecast as depicted by line 11 of Exhibit A-12, Schedule  
17 B5.3, page 1, accurately represents the capital expenditures that can reasonably be  
18 expected to continue operation of nuclear assets of similar age and vintage. My  
19 summation of projects reflects DTE Electric's commitment to ensure the safe and  
20 reliable operation of Fermi 2 through its current operating license expiration in  
21 2045. As I have expressed previously, these capital expenditures are prudent and  
22 reasonable given the regulations, goals and conditions under which Fermi 2  
23 operates.

Line  
No.

1 **Nuclear Generation O&M Expense**

2 **Q132. Can you provide an outline of your Nuclear Generation O&M discussion?**

3 A132. Yes. My testimony will begin with the O&M Expenses Overview and then discuss  
4 and support the additional details regarding:

- 5 • Rate Case Adjustments
- 6 • Adjusted Historical Test Period, and
- 7 • Projected Adjustments

8

9 **O&M Expenses Overview**

10 **Q133. Can you provide an overview of the Nuclear Generation O&M expenses**  
11 **supported by your testimony?**

12 A133. Exhibit A-13, Schedule C5.3, page 1, line 24 from left to right depicts the O&M  
13 expenses for the 12-month historical test period ended December 31, 2023,  
14 adjustments to the historical test period, and then the forecasted O&M expenses for  
15 the 12-month projected test period ending December 31, 2026.

16

17 The actual O&M expenses by FERC account for the 12-month historical test period  
18 ended December 31, 2023, were \$183.9 million as shown in column (c). Rate case  
19 adjustments are made in column (d) to reduce O&M by \$27.9 million to account  
20 for the Nuclear Surcharge, in column (e) to reclassify Project Evaluation Review  
21 Committee (PERC) nuclear O&M project expenditures, in column (f) to eliminate  
22 the portion of industry association fees reported as lobbying expenses, and factor  
23 other normalization adjustment by \$5.2 million in column (g). These rate case  
24 adjustments result in \$161.2 million of adjusted O&M for the 2023 historical test  
25 period as shown in column (h).

Line  
No.

1 Projected adjustments of \$4.5 million, \$4.1 million and \$4.4 million in columns (i),  
2 (j) and (k) respectively account for inflation. The \$3.4 million decrease in column  
3 (l) is subtracted to account for outage accrual adjustments and O&M is reduced by  
4 \$10.9 million in column (m) to account for the total PERC expense in the forecasted  
5 test period as supported by calculations performed by Company Witness Uzenski.  
6 These projected adjustments yield a total change of \$1.2 million as shown in  
7 column (n).

8

9 With the above adjustments, the forecasted O&M expenses for the 12-month  
10 projected test period are \$160.0 million as shown in column (o).

11

12 **Q134. What projected Total Nuclear Power Generation O&M expenses are you**  
13 **supporting for the Projected Test year?**

14 A134. I am supporting projected Total Nuclear Power Generation O&M expenses of  
15 \$160.0 million as shown in Exhibit A-13, Schedule C5.3, line 24, column (o) as  
16 reasonable and prudent for 2026.

17

18 **Rate Case Adjustments**

19 **Q135. Can you explain the basis for the Rate Case Adjustments in column (d) of**  
20 **Exhibit A-13, Schedule C5.3, page 1?**

21 A135. Site security and radiation protection costs were removed from base rates and  
22 recognized in the Nuclear Surcharge as established in DTE Electric Case No. U-  
23 14399. The Nuclear Surcharge reduction of \$27.9 million as summed on line 24,  
24 column (d) accomplishes this requirement. The complete elimination of all

Line  
No.

1 financial statement impacts of the Nuclear Surcharge are supported by Witness  
2 Uzenski.

3

4 **Q136. Can you explain the basis for the Rate Case Adjustments in column (e) of**  
5 **Exhibit A-13, Schedule C5.3, page 1?**

6 A136. The Reclassify PERC adjustment nets to zero as shown on line 24, column (e). This  
7 reclassification is performed to make explicit the \$15.0 million PERC Base  
8 Expense shown on line 21, column (e) and the \$12.5 million of PERC Regulatory  
9 Asset amortization shown on line 22, column (e) are not inflated in the projected  
10 adjustments. I will explain the PERC Regulatory Asset mechanism later in my  
11 testimony.

12

13 **Q137. Can you explain the basis for the Rate Case Adjustments in column (f) of**  
14 **Exhibit A-13, Schedule C5.3, page 1?**

15 A137. Excluded membership fees were removed from rate base as shown on line 24,  
16 column (f). This adjustment is performed to make explicit the portion of industry  
17 association fees reported as lobbying expenses are excluded from Nuclear  
18 Generation's rate base. I will explain Nuclear Generation's participation with  
19 regulatory agencies and industry associations later in my testimony.

20

21 **Q138. Can you explain the basis for the Rate Case Adjustments in column (g) of**  
22 **Exhibit A-13, Schedule C5.3, page 1?**

23 A138. Normalization adjustments account for irregular expenses (or absence of expenses)  
24 in the historical test year as shown on line 24, column (g). This adjustment of \$5.2  
25 million recognizes that Nuclear Generation received a one-time credit from Utility

Line  
No.

1 Service Alliance for \$1.1 million and that Nuclear Generation staffing levels (and  
2 associated expenses) in the historical test period were \$4.1 million below the long-  
3 term sustainable thresholds required to operate the Fermi 2 Power Plant and that  
4 Nuclear Generation staffing will return to the long-term sustainable levels leading  
5 into the 12-month projected test period ending December 31, 2026.

6

7 **Q139. Was the normalization adjustment in column (g) introduced in Case No. U-**  
8 **21534?**

9 A139. Yes. Although Case No. U-21534 used the 12-month period ending December 31,  
10 2022, as its historical test period, Michigan Public Service Commission Staff  
11 requested through discovery Nuclear Generation's updated Adjusted Historical  
12 Test Period expenses for the 12-month period ending December 31, 2023, and  
13 Nuclear Generation included the same adjustments. Staff included these updated  
14 Adjusted Historical Test Period expenses in their testimony and did not recommend  
15 further adjustment.

16

17 **Adjusted Historical Test Period**

18 **Q140. Can you explain the components that constitute the actual Total Nuclear**  
19 **Power Generation O&M expenses for adjusted historical test period in line 24,**  
20 **column (h) of Exhibit A-13, Schedule C5.3, page 1?**

21 A140. Total Nuclear Generation O&M of \$161.2 million for the adjusted historical test  
22 period consists of the Nuclear Organization, PERC Base Expense, amortization of  
23 the PERC Regulatory Asset, regulatory assessments and dues, and refueling outage  
24 expenses. I detail these expenses for the 2023 historical period on page 2 of Exhibit  
25 A-13, Schedule C5.3.

Line  
No.

1   **Q141. What is the need for and basis of the “Nuclear Organization” expenses that**  
2           **are included in the 2023 historic period for Operation and Maintenance**  
3           **Expenses on Exhibit A-13, Schedule C5.3, page 2, line 1?**

4   A141. Nuclear Organization expenses are the baseline employee, services and material  
5           expenses required to safely and reliably operate Fermi 2. The Nuclear Organization  
6           expenses for the historical test period ended December 31, 2023, were \$96.1  
7           million.

8

9   **Q142. What is the need for and basis for the “PERC Base Expense” expenses that**  
10           **are included in the 2023 historic period for Operation and Maintenance**  
11           **Expenses on Exhibit A-13, Schedule C5.3, page 2, line 2?**

12   A142. As explained and supported by Witness Uzenski, the Commission Order in Case  
13           No. U-18014 approved an annual base level of PERC expenses of \$4.9 million for  
14           nuclear O&M projects and the Commission Order in Case No. U-20561 increased  
15           the approved annual base level of PERC expenses to \$15.0 million; the PERC Base  
16           Expense of \$15.0 million depicted on line 2 recognizes those approvals.

17

18   **Q143. What is the need for and basis for the “Reg Asset Amortization - PERC”**  
19           **expenses that are included in the 2023 historic period for Operation and**  
20           **Maintenance Expenses on Exhibit A-13, Schedule C5.3, page 2, line 3?**

21   A143. As explained and supported by Witness Uzenski, the Commission Order in Case  
22           No. U-18014 approved a regulatory asset for annual PERC projects O&M  
23           expenditures that exceed the annual base level of PERC expenses of \$4.9 million  
24           for nuclear O&M projects. In Case No. U-20561, the Commission Order updated  
25           the approved regulatory asset for annual PERC projects O&M expenditures that

Line  
No.

1 exceed the annual base level of PERC expenses of \$15.0 million for nuclear O&M  
2 projects; the Commission has left unchanged this annual base level PERC expense  
3 in subsequent DTE Electric rate cases. The Order in Case No. U-18014 established  
4 the amortization period of this regulatory asset as five years. Consistent with that  
5 Order, the \$12.5 million depicted on line 3 is the amount of the PERC Regulatory  
6 Asset amortized in 2023.

7

8 **Q144. What is the need for and basis for the “Regulatory Assessments and Dues”**  
9 **expenses that are included in the 2023 historic period for Operation and**  
10 **Maintenance Expenses on Exhibit A-13, Schedule C5.3, page 2, line 4?**

11 A144. A majority of these assessments and dues are regulatory driven, such as those  
12 assessments and dues required by the NRC to cover oversight of the plant. In  
13 addition, assessments and dues are associated with licensing requirements  
14 including the Emergency Response Organization (ERO) and various industry  
15 groups.

16

17 Industry groups include the Institute of Nuclear Power Operations (INPO), which  
18 assists utilities in operating nuclear plants to the highest safety standards, the  
19 Nuclear Energy Institute (NEI), which assists in common issues impacting the  
20 nuclear industry, as well as the Electric Power Research Institute (EPRI) and the  
21 General Electric Boiling Water Reactor Owners’ Group, both of which sponsor  
22 research that is used by nuclear plants to operate more safely and economically.

23

24 The ERO supports the Fermi 2 Emergency Plan which is a license requirement  
25 necessary to ensure the health and safety of the public during emergency response



Line  
No.

1 events. The ERO funds federal, state and local county emergency facilities in  
2 support of the Fermi 2 Emergency Plan.

3

4 **Q145. Which assessments and dues are non-discretionary (i.e. mandated)?**

5 A145. NRC, INPO and ERO assessments and dues are non-discretionary.

6

7 **Q146. Why does the Company pay non-discretionary assessments and dues?**

8 A146. These fees are either government-imposed or industry-imposed mandatory fees.

9 NRC assessments and fees are government-imposed mandatory fees as set forth at

10 10 CFR 50.170 and 10 CFR 50.171. ERO assessments and dues are also

11 government-imposed mandatory fees that include the Federal Emergency

12 Management Agency (FEMA) fees as set forth in 44 CFR 354 and other fees to the

13 State of Michigan, Wayne County, Monroe County, and City of Amherstburg,

14 Canada in relation to their required support of the offsite radiological emergency

15 preparedness program. INPO assessments and fees are industry-imposed

16 mandatory fees.

17

18 **Q147. What are some specific benefits that the NRC provides DTE Electric and**  
19 **contributes to the safe, reliable, and economic operation of the Fermi 2 Power**  
20 **Plant?**

21 A147. The NRC is the independent government agency responsible for ensuring the safe

22 use of radioactive material for beneficial civilian purposes (such as commercial

23 electricity generation) while protecting people and the environment. The NRC

24 regulates commercial nuclear power plants through establishment of standards and

25 regulations, licensing, inspection, and enforcement of its standards and regulations.

Line  
No.

1 An example of a specific NRC interaction with DTE Electric in support of safe,  
2 reliable operation is the NRC assigns onsite resident inspectors to the Fermi 2  
3 Power Plant, the resident inspectors have unfettered access to the plant and plant  
4 personnel to provide oversight, perform inspections, review plant performance and  
5 independently ensure DTE Electric is operating the Fermi 2 Power Plant in  
6 accordance with its NRC operating license and NRC rules and regulations.

7

8 **Q148. What are some specific benefits that ERO provides DTE Electric and**  
9 **contributes to the safe, reliable, and economic operation of the Fermi 2 Power**  
10 **Plant?**

11 A148. Emergency Response Organization is a collection of federal, state and local  
12 agencies that support Fermi 2's offsite emergency preparedness program. FEMA is  
13 the federal agency that coordinates the national effort to provide state and local  
14 governments with radiological emergency expertise and issues regulations and  
15 policies to ensure adequate capabilities exist to prevent, protect against, mitigate  
16 the effects of, respond to and recover from an incident at a commercial nuclear  
17 power plant. The State of Michigan is responsible for coordinating state and local  
18 responses to a radiological emergency at the Fermi 2 Power Plant. Wayne County  
19 and Monroe County are the two counties within the boundaries of the Fermi 2  
20 Emergency Preparedness Plan and are responsible for coordinating and executing  
21 the local response to a radiological emergency at the Fermi 2 Power Plant.

22

23 **Q149. What are some specific benefits that INPO provides DTE Electric that**  
24 **contributes to the safe, reliable, and economic operation of the Fermi 2 Power**  
25 **Plant?**

Line  
No.

1 A149. In general, INPO's mission is "to promote excellence" within the industry and to  
2 that end, has established performance objectives and criteria that are broader and  
3 seek a level of performance above the level required by NRC regulations.

4  
5 A specific example of the mandatory nature of INPO that contributes to safe,  
6 reliable and economic operation of Fermi 2 Power Plant is NRC regulations at 10  
7 CFR 50.120 and 10 CFR 55.59 that requires training programs for certain plant  
8 personnel to be established, implemented, and maintained using a systems approach  
9 to training (10 CFR 55.4 (SAT)) which provides for the systematic determination  
10 of job performance and qualification requirements and for periodic retraining of  
11 personnel. The INPO National Academy for Nuclear Training (NANT) monitors  
12 the implementation of the SAT process at power plants through periodic training  
13 program accreditation reviews conducted by the National Nuclear Accrediting  
14 Board (NNAB). All US commercial nuclear power plants satisfy the SAT  
15 requirements of 10 CFR 50.120 and 10 CFR 55.59(c) through accreditation by  
16 NANT.

17

18 **Q150. Why does the Company pay the discretionary assessments and dues?**

19 A150. Although not specifically mandated, voluntary participation with organizations  
20 such as EPRI and NEI are critical within a nuclear business model. In particular,  
21 organizations like EPRI support research and development that includes sharing of  
22 products and services to ensure nuclear asset owners benefit as a whole from shared  
23 information. These products and services would be unaffordable without group  
24 participation and funding. The role provided by NEI is valuable to plant owners  
25 and operators in helping to shape important industry issues and regulation through

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1 a coordinated and solidified approach. The nuclear industry clearly recognizes that  
2 any one plant can abruptly upset the entire industry due to performance issues. As  
3 a result, this industry believes in significant group participation and knowledge  
4 sharing to help preclude such an event.

5

6 **Q151. What are some specific benefits that EPRI provides DTE Electric that**  
7 **contributes to the safe, reliable, and economic operation of the Fermi 2 Power**  
8 **Plant?**

9 A151. EPRI provides DTE Electric with the benefit of access to state-of-the-art industry  
10 research in the functional areas such as nuclear fuel reliability, reactor vessel and  
11 internals aging management, value-based maintenance, training, nuclear risk and  
12 safety management, and radiation safety.

13

14 To further provide an example of a specific benefit, EPRI membership is an integral  
15 part of DTE Electric's (and indeed the nuclear industry's) probabilistic risk  
16 assessment (PSA) program. The PSA engineer qualification at Fermi 2 requires  
17 learning the EPRI PSA courses and PSA tools used by DTE Electric such as MAAP  
18 5, GOTHIC and PHOENIX, which are all developed and supported by EPRI.  
19 Without EPRI membership, DTE Electric would have to develop duplicative PSA  
20 education courses and PSA tools which would not be reasonable nor prudent.

21

22 **Q152. What are some specific benefits that NEI provides DTE Electric that**  
23 **contributes to the safe, reliable, and economic operation of the Fermi 2 Power**  
24 **Plant?**

Line  
No.

1 A152. NEI provides DTE Electric (as an NEI member) access to its Personnel Access  
2 Database System (PADS). NEI membership is required to access PADS. PADS is  
3 a database maintained and administered by NEI and contains information provided  
4 by PADS participants concerning individuals who request access to a commercial  
5 nuclear facility; this information includes dates that an individual was granted or  
6 denied access, an individual's training and radiological dosage records. NRC  
7 regulations do not require the use of PADS but PADS does offer an efficient  
8 method for commercial nuclear plant licensees to comply with NRC regulations at  
9 10 CFR 73.56 and to share information about individuals who were denied access  
10 or have had their access terminated per NRC regulations. Without access to PADS,  
11 DTE Electric would have to create a duplicative system of verifying an individual's  
12 plant access history – which would not be reasonable nor prudent.

13

14 NEI also provides DTE Electric with resources known as the Composite Adversary  
15 Force (CAF) to support NEI Force-on-Force security inspections. NEI membership  
16 is required to use the CAF. Since 2004, the NRC has relied on the NEI CAF to  
17 provide a credible, well-trained and consistent mock adversary in Force-on-Force  
18 inspections; Force-on-Force inspections assess a nuclear power plant's physical  
19 protection measures to defend against a "design-basis threat." To avoid conflicts of  
20 interest, the NRC requires a clear separation of functions between the mock  
21 adversary and the plant security forces. NRC regulations do not require the use of  
22 the NEI CAF but the NEI CAF does provide NEI members with an efficient means  
23 for commercial nuclear licensees to conduct NRC Force-on-Force inspections.  
24 Without NEI CAF, DTE Electric would be required to establish a duplicative mock

Line  
No.

1 adversary force using independent mock adversaries that met NRC standards –  
2 which would not be reasonable nor prudent.

3

4 **Q153. How does NEI support safer nuclear operations through collective nuclear**  
5 **industry action?**

6 A153. NEI has supported a collective industry response to the events concerning the  
7 Fukushima Dai-ichi nuclear power plant – in particular, NEI led the nuclear  
8 industry's adoption of the Diverse and Flexible Coping Strategies (FLEX) which  
9 increases each plant's defense-in-depth for beyond-design-basis scenarios. NEI has  
10 also led industry efforts to strengthen cybersecurity regulations. Certainly, these  
11 initiatives to make nuclear generators safer are in the best interests of our  
12 communities and DTE Electric's association with NEI is reasonable and prudent.

13

14 **Q154. Does DTE Electric use other discretionary memberships to benefit our**  
15 **customers and the communities the Company serves?**

16 A154. Yes. An example of another discretionary membership is NUPIC (Nuclear  
17 Procurement Issues Corporation) which is a cooperative program for performing  
18 and sharing audits of suppliers providing DTE Electric (and the nuclear industry)  
19 nuclear-quality parts. NRC regulations (*generally*, Appendix B to Part 50) require  
20 NRC licensees such as DTE Electric to audit its suppliers of nuclear-quality parts  
21 and maintain an Approved Suppliers List (ASL) – the number of such suppliers is  
22 quite large, so NUPIC allows members to use the audits of other members to  
23 maintain the suppliers on each licensee's ASL. Without NUPIC, DTE Electric  
24 would be required to audit every supplier listed on its ASL by itself which would  
25 not be reasonable nor prudent.

Line  
No.

1   **Q155. What is the need for and basis for “Total Refueling Outage” expenses for the**  
2           **2023 historical test period on Exhibit A-13, Schedule C5.3, page 2, line 10?**

3   A155. As discussed earlier in my testimony, the Fermi 2 plant operates on a 24-month  
4           refueling cycle such that every 24 months Fermi 2 shuts down to refuel the reactor.  
5           The “Total Refueling Outage” expenses are those costs necessary to (1) refuel the  
6           Fermi 2 reactor and (2) perform offline maintenance to ensure Fermi 2 can operate  
7           safely and reliably for the next operating cycle.

8  
9           The “Total Refueling Outage” expense consists of the actual refueling outage costs  
10          (line 7), the refueling outage accrual (line 8) and the refueling outage accrual  
11          reversals (line 9) for the 2023 historical period. Line 10 nets these three components  
12          and represents an accounting practice of levelizing incremental refueling expenses  
13          by accruing the anticipated refueling expenses over the term of an operating cycle.

14

15   **Q156. Why does DTE Electric levelize its incremental refueling outage expenses?**

16   A156. DTE Electric levelizes its incremental refueling outage expenses so that the  
17          difference in expense between outage and non-outage years does not burden DTE  
18          Electric customers with large rate fluctuations or create financial swings for the  
19          Company. For example, if the Company bases the rate request on the projections  
20          for a refueling outage year and all the expenses of that outage appear in that year’s  
21          projections, then the Company would be presenting an unnecessarily high cost of  
22          providing Fermi 2 generation over the period the rates are in effect. The inverse is  
23          also true if the Company used a non-refueling outage year projection for the same  
24          purpose. This is consistent with the treatment in prior cases where the Commission  
25          has allowed levelized refueling outage expenses in setting rates.

Line  
No.

1 **Q157. What is the basis for the “Refuel Outage” expense at \$1.0 million for the 2023**  
2 **historical test period shown on Exhibit A-13, Schedule C5.3, page 2, line 7?**

3 A157. This is the actual refuel outage expenditures incurred in the 2023 historical test  
4 period for RF22.

5  
6 **Q158. How does DTE Electric manage incremental refueling outage expenses?**

7 A158. The Company manages incremental expenses through structured planning and  
8 preparation that is consistent with industry standards and processes. We  
9 implemented rigorous financial controls that supported daily management of  
10 resources during the execution phase of the refueling outage. This management of  
11 resources includes daily reviews of scope completion, schedule and budget. As  
12 work completes, contracted resources exit promptly from the site to ensure that  
13 costs are controlled.

14  
15 **Q159. What is the basis for the “Refuel Outage Accrual” expenses at \$23.6 million**  
16 **for the 2023 historical test period shown on Exhibit A-13, Schedule C5.3, page**  
17 **2, line 8?**

18 A159. This is the actual amount accrued in the historical test period for RF22.

19  
20 **Q160. How does DTE Electric determine the value of the Refuel Outage Accrual?**

21 A160. As the purpose of the Refuel Outage Accrual is to levelize the costs of refueling  
22 outages over the appropriate time horizon, DTE Electric developed a model outage  
23 template that defines a routine baseline refueling outage in terms of timing, and  
24 incremental O&M expenditures for labor, services, materials and other outage  
25 costs. It is important to note that the Refuel Outage Accrual is for those incremental



Line  
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1 O&M costs associated with a refueling outage; routine expenses such as DTE  
2 Electric Nuclear Generation straight-time labor, structural overtime and year-round  
3 supplier services that are incurred regardless of the outage are “Nuclear  
4 Organization.”

5

6 As I will discuss later in my testimony, incremental outage costs that are generally  
7 not associated with the baseline outage activities or cause significant variation in  
8 outage costs from outage-to-outage are assigned to PERC O&M.

9

10 **Q161. What is the basis for the “Refuel Outage Reversal” of \$1.0 million for the 2023**  
11 **historical test period shown on Exhibit A-13, Schedule C5.3, page 2, line 9?**

12 A161. This is the actual amount of outage accrual that had been accrued in advance for  
13 RF22 and credited to O&M in the historical test period.

14

15 **Projected Adjustments**

16 **Q162. Can you explain the basis for the inflation adjustments in columns (i), (j) and**  
17 **(k) on line 24 of Exhibit A-13, Schedule C5.3, page 1?**

18 A162. The labor and material prorated inflation adjustment rates of 3.4% for 2024, 3.0%  
19 for 2025 and 3.1% for 2026 are supported by the testimony of Witness Uzenski.  
20 Nuclear Generation applied these forecasted inflation rates to the adjusted historical  
21 test period costs in column (h).

22

23 **Q163. Can you explain the basis for the Outage Accrual adjustment in column (l) on**  
24 **line 24 of Exhibit A-13, Schedule C5.3, page 1?**

Line  
No.

1 A163. The Outage Accrual adjustment is to normalize the outage accrual for the 2026  
2 projected test period to approximately \$22.5 million. The reduction of \$3.4 million  
3 depicted in column (l), line 24 is the mathematical difference between the \$23.6  
4 million total refuel outage for the adjusted historical period (Exhibit A-13, Schedule  
5 C5.3, column (b), line 10, page 2) inflated by the annual inflation factors depicted  
6 in Note 4 of Exhibit A-13, Schedule C5.3, page 1 to approximately \$25.9 million  
7 and the \$22.5 million outage accrual for the 2026 projected test period. This  
8 Outage Accrual adjustment reflects our commitment to improving refueling outage  
9 performance and reducing future outage O&M expenditures.

10

11 **Q164. What duration have you projected for RF23?**

12 A164. The 2025 PSCR Plan (Case No. U-21594) projected an outage duration of 45 days  
13 for RF23 (projected for spring 2026).

14

15 **Q165. Can you explain the basis for the PERC Amortization adjustment in column**  
16 **(m) on line 24 of Exhibit A-13, Schedule C5.3, page 1?**

17 A165. As explained and supported by Witness Uzenski, the Commission Order in Case  
18 No. U-18014 not only approved an annual base level of PERC expenses for nuclear  
19 O&M projects, but also provided deferral and amortization treatment for any  
20 expenses over or under the base amount. The PERC Base expense was changed by  
21 \$10.1 million from \$4.9 million per year to \$15.0 million per year in the May 8,  
22 2020 Order in Case No. U-20561.

23

24 The PERC Amortization reduction of \$10.9 million in column (m) on line 24  
25 consists of the \$0.0 million change in the approved annual PERC Base Expense as

Line  
No.

1 shown in column (m) on line 21 and a forecasted reduction of \$10.9 million in the  
2 amortization of the PERC Regulatory Asset as shown in column (m) on line 22.

3  
4 The Total PERC Expense for the 2026 projected test period is forecasted at \$16.3  
5 million as shown in column (o) on line 23. The derivation of this Total PERC  
6 Expense is shown on Exhibit A-13, Schedule C5.17 and is sponsored by Witness  
7 Uzenski; I detail the projects comprising line 2 of Exhibit A-13, Schedule C5.17 in  
8 Exhibit A-13, Schedule C5.16, page 1.

9  
10 **Q166. Can you explain the Total PERC O&M Expenditures detailed in Exhibit A-**  
11 **13, Schedule C5.16, page 1?**

12 A166. This exhibit shows the by-project PERC O&M expenditures for the 2023 historical  
13 period and projected Calendar Years 2024, 2025, and 2026 planned expenditures  
14 totaling \$7.7 million, \$30.5 million, \$11.9 million and \$17.7 million respectively.

15  
16 **Q167. Can you explain how DTE Electric determines which projects are included in**  
17 **PERC O&M as detailed in Exhibit A-13. Schedule C5.16, page 1?**

18 A167. Exhibit A-13, Schedule C5.16 is the updated list of PERC O&M projects. DTE  
19 Electric has provided similar updated exhibits in each of the past rate cases since  
20 Case No. U-18014 established the PERC O&M regulatory asset construct. PERC  
21 O&M projects expenditures are those incremental expenditures associated with  
22 Nuclear Generation O&M projects. I will provide a rationale for inclusion of select  
23 projects in the PERC O&M later in my testimony.

Line  
No.

1   **Q168. How do the Total PERC O&M Expenditures on line 34 of Exhibit A-13,**  
2       **Schedule C5.16, page 1 relate to Exhibit A-13, Schedule C5.17?**

3   A168. As an example, the projected total PERC O&M expenditures of approximately  
4       \$30.5 million for Calendar Year 2024 shown in Exhibit A-13, Schedule C5.16, page  
5       1, line 34, column (c) flows to Exhibit A-13, Schedule C5.17, page 1, line 2, column  
6       (d).

7  
8   **Q169. How does the PERC amortization expense on line 17 of Exhibit A-13, Schedule**  
9       **C5.17, page 1 relate to Exhibit A-13, Schedule C5.3, page 1?**

10   A169. Exhibit A-13, Schedule C5.17 shows the calculation for PERC amortization that  
11       was derived from Exhibit A-13, Schedule C5.16, Page 1. Exhibit A-13, Schedule  
12       C5.17, page 1, line 17, column (g) shows \$1.6 million as the calculated amortized  
13       portion of PERC O&M for the 12-month projected test period ending December  
14       31, 2026. This \$1.6 million is used in Exhibit A-13, Schedule C5.3, page 1, line 22,  
15       column (o).

16

17   **Q170. What was the rationale for the Refueling Outage Planning, Readiness and**  
18       **Demobilization project shown on line 1 of Exhibit A-13, Schedule C5.16, page**  
19       **1?**

20   A170. As I discussed earlier in my direct testimony, DTE Electric begins planning for the  
21       upcoming refueling outage at approximately T-24 months prior to the refueling  
22       outage. Expenditures for refueling outage planning, scheduling and readiness  
23       follow a 24-month pattern and as such, do not lend themselves to a levelized  
24       expenditure schedule; the amount of expenditures can also vary from outage-to-  
25       outage depending on refueling outage work scope. Planning activities include work

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1 package planning, work order reviews and resource planning; scheduling includes  
2 work plan integration and resource levelization efforts; readiness includes physical  
3 tasks such as staging parts, building some scaffolding that can be done prior to the  
4 refueling outage, readying temporary power carts, and setting up temporary  
5 infrastructure needs such as additional computers and housing trailers. The Refuel  
6 Outage Planning line item was included in the original PERC O&M discussion in  
7 Case No. U-18014 and has been updated accordingly with each subsequent DTE  
8 Electric rate case.

9

10 **Q171. What was the rationale for the Desludge - Torus project shown on line 15 of**  
11 **Exhibit A-13, Schedule C5.16, page 1?**

12 A171. The torus is a water-filled donut-shaped containment structure designed to absorb  
13 excess thermal energy and provide emergency water to the reactor core during a  
14 postulated accident scenario. Each refueling outage specially-qualified divers de-  
15 sludge the torus to minimize the amount of debris within the torus; this debris  
16 normally accumulates over the course of the operating cycle. Once the torus has  
17 been de-sludged, the divers inspect and repair the submerged coatings of the torus  
18 containment structure; the divers also inspect and replace pump suction strainers.  
19 The Desludge – Torus project was first included in the PERC O&M exhibit in Case  
20 No. U-20162 and has had updated project expenditures included in subsequent rate  
21 case PERC O&M exhibits.

22

23 **Q172. What was the rationale for the Reactor Feed Pump Turbine (RFPT)**  
24 **Inspections project shown on line 5 of Exhibit A-13, Schedule C5.16, page 1?**

Line  
No.

1 A172. The Reactor Feed Pump Turbines (RFPTs) require a full tear-down inspection  
2 approximately every ten years to satisfy loss control criteria. Fermi 2 has two  
3 RFPTs (North and South). Each RFPT drives one Reactor Feed Pump (RFP) which  
4 in turn supplies the driving force for reactor feed water. DTE Electric completed  
5 the inspection of the South RFPT in RF21 (2022) and completed the North RFPT  
6 inspection in RF22 (2024). The RFPT inspections were first included with the Case  
7 No. U-20836 PERC O&M Exhibit and has had updated project expenditures with  
8 subsequent rate case PERC O&M exhibits.

9

10 **Q173. What was the rationale for the Residual Heat Removal Heat Exchanger (RHR**  
11 **HX) coating project shown on line 9 of Exhibit A-13, Schedule C5.16, page 1?**

12 A173. A requirement for the renewed Fermi 2 operating license is to perform inspections  
13 of internal coatings of certain piping, piping components, heat exchangers and tanks  
14 where the loss of the coating or lining could impact the ability of that equipment to  
15 perform its function during the Fermi 2 Period of Extended Operations through  
16 2045; the Fermi 2 Residual Heat Removal Heat Exchangers (RHR HX) have such  
17 internal coatings. Fermi 2 has two RHR HXs ('A' and 'B'), both of which are  
18 nuclear-safety equipment. Each RHR HX supports an independent and redundant  
19 division of nuclear-safety equipment where the RHR HX transfers residual heat  
20 away from the nuclear systems and to the Fermi 2 Ultimate Heat Sink during certain  
21 accident scenarios. Previous inspections of the original RHR HX coatings had  
22 shown evidence of degradation; therefore, to ensure the RHR HX coatings would  
23 support safe operations through 2045, DTE Electric is replacing the internal  
24 coatings of the RHR HXs. DTE Electric completed the coating replacement of the  
25 RHR HX A in RF21 and completed the replacement of the RHR HX B coating in

Line  
No.

1 RF22. The RHR HX coating replacements project was first included with the Case  
2 No. U-20836 PERC O&M Exhibit and has had updated project expenditures with  
3 subsequent rate case PERC O&M exhibits.

4

5 **Q174. What was the rationale for the Hydraulic Control Unit (HCU) preventative**  
6 **maintenance project shown on line 10 of Exhibit A-13, Schedule C5.16, page**  
7 **1?**

8 A174. The Fermi 2 Hydraulic Control Units (HCUs) require a one-time preventative  
9 maintenance (replacement of internal soft components such as diaphragms and  
10 gaskets, filters as well as directional control valves) to ensure safe operations  
11 through 2045. Fermi 2 has 185 HCUs – one for each control rod drive mechanism  
12 (CRDM). The HCU controls hydraulics to the CRDM. DTE Electric has leveled  
13 the HCU preventative maintenance over several outages and completed  
14 preventative maintenance activities on 34 HCUs in RF22 and projects to complete  
15 preventative maintenance activities on 25 HCUs in RF23 with another 24 HCUs  
16 receiving replacement directional control valves. The HCU preventative  
17 maintenance project was first included with the Case No. U-20162 PERC O&M  
18 Exhibit and has had updated project expenditures with subsequent rate case PERC  
19 O&M exhibits.

20

21 **Q175. What was the rationale for the Force-on-Force inspections (FOF) shown on**  
22 **line 13 of Exhibit A-13, Schedule C5.16, page 1?**

23 A175. Force-on-Force (FOF) inspections are NRC inspections and exercises that assess  
24 the ability of a nuclear licensee such as DTE Electric to defend a nuclear power  
25 plant from a design-basis-threat. The NRC FOF includes a mock adversary force

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1 (MAF) that simulates hostile actions against the plant's security personnel and  
2 systems. These NRC FOF inspections occur approximately every three years. The  
3 NRC last performed a FOF at Fermi 2 in 2022 and DTE Electric projects the next  
4 NRC FOF in 2025. The FOF inspections were first included with the Case No. U-  
5 20162 PERC O&M Exhibit and has had updated project expenditures with  
6 subsequent rate case PERC O&M exhibits.

7

8 **Q176. What was the rationale for the High Energy Line Break (HELB) analysis**  
9 **shown on line 3 of Exhibit A-13, Schedule C5.16, page 1?**

10 A176. Fermi 2 Power Plant is maintained and operated per its NRC license. Supporting  
11 the Fermi 2 license are many technical specifications, designs, configuration  
12 controls and design calculations. One such design calculation affects environmental  
13 (temperature, humidity, pressure) conditions that can be assumed during plant  
14 operating scenarios such as a high energy line break (HELB). The HELB analysis  
15 updates the Fermi 2 environmental calculations using modern models such as the  
16 EPRI GOTHIC which in turn allows DTE Electric to reevaluate and provide  
17 additional margin to certain Fermi 2 technical specifications and reduce the  
18 likelihood of an unplanned limited condition of operation.

19

20 **Q177. What was the rationale for the Independent Spent Fuel Storage Installation**  
21 **(ISFSI) and ISFSI fuel characterization shown on lines 32 and 31 of Exhibit**  
22 **A-13, Schedule C5.16, page 1?**

23 A177. Fermi 2 ISFSI campaigns remove spent nuclear fuel assemblies from the Fermi 2  
24 spent nuclear fuel pool, load the spent nuclear fuel assemblies into NRC-licensed  
25 dry casks, and then transport the dry casks to their interim storage location at the



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1 Fermi 2 ISFSI Pad. Prior to loading the spent nuclear fuel assemblies into the casks,  
2 DTE Electric must characterize the spent nuclear fuel to ensure the spent nuclear  
3 fuel assembly remains intact and that its composition is as expected to ensure the  
4 spent nuclear fuel loaded into each cask is consistent with the dry cask license. The  
5 2023 ISFSI campaign included 10 dry casks and transitioned 680 spent nuclear fuel  
6 assemblies from the Fermi 2 spent fuel pool to the Fermi 2 ISFSI Pad. The ISFSI-  
7 related expenditures were first included with the Case No. U-20162 PERC O&M  
8 Exhibit and has had updated project expenditures with subsequent rate case PERC  
9 O&M exhibits.

10

11 **Q178. What was the rationale for the Spent Fuel Pool (SFP) cleanup campaign shown**  
12 **on line 2 of Exhibit A-13, Schedule C5.16, page 1?**

13 A178. The Fermi 2 Spent Fuel Pool (SFP) is a small, water-filled pool adjacent to the  
14 reactor and is used to store spent nuclear fuel, incoming new nuclear fuel, control  
15 rod blades (CRBs) and nuclear instrumentation equipment such as dry tubes and  
16 local power range monitors (LPRMs). While ISFSI campaigns transition spent  
17 nuclear fuel from the SFP to dry-cask storage, the SFP storage locations for CRBs  
18 and nuclear instrumentation equipment are also finite and periodically DTE Electric  
19 must dispose of this depleted equipment to clear space for the CRB/SRM/IRM  
20 removals projected in upcoming refueling outages. DTE Electric removed and  
21 disposed of 28 CRBs and 7 dry tubes and 3 LPRMs from the SFP. The SFP cleanup  
22 campaigns were first included with the Case No. U-20162 PERC O&M Exhibit and  
23 has had updated project expenditures with subsequent rate case PERC O&M  
24 exhibits. DTE Electric projects to conclude this spent fuel pool cleanup campaign  
25 in 2025.

Line  
No.

1    **Q179. What was the rationale for the Core Shroud Inspections shown on line 6 of**  
2           **Exhibit A-13, Schedule C5.16, page 1?**

3    A179. The core shroud is a cylindrical shroud that directs coolant flow through the core  
4           and helps maintain fuel alignment to ensure control rods can be inserted into the  
5           core. DTE Electric performs core shroud inspections approximately every ten years  
6           to monitor the integrity of the core shroud per EPRI guidelines endorsed by the  
7           NRC; however, with Fermi 2's transition to the 24-month cycle, DTE Electric was  
8           required to perform the core shroud inspections one outage year earlier than  
9           otherwise required. DTE Electric performed the core shroud inspections in RF22.  
10          DTE Electric last performed the core shroud inspection in RF18 (2017) which was  
11          depicted in the Case No. U-20162 PERC O&M exhibit.

12

13   **Q180. What was the rationale for the License Renewal Inspections shown on line 16**  
14          **of Exhibit A-13, Schedule C5.16, page 1?**

15    A180. Once Fermi 2 transitions to its Period of Extended Operations in 2025, the License  
16          Renewal Implementation capital project will complete and be in service. There will  
17          be ongoing incremental inspections required as a part of the Fermi 2 renewed  
18          license which DTE Electric will account for in the License Renewal Inspection  
19          project. The License Renewal Inspection project was included in the Case No. U-  
20          21297 PERC O&M Exhibit.

21

22   **Q181. What was the rationale for the Feed Water Heater (FWH) Bridging Strategy**  
23          **project analysis shown on line 17 of Exhibit A-13, Schedule C5.16, page 1?**

24    A181. I have discussed the technical importance of the FWHs in the capital discussion.  
25          Emergent repairs to the #3S FWH were performed in RF20. DTE Electric

Line  
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1 performed inspections of these six FWHs in RF21 to support safe, reliable operation  
2 until RF22. DTE Electric completed inspections and repairs to the #3S, #3N, #4S,  
3 #4N, #5S and #5N FWHs to support reliable operation until these six FWHs are  
4 replaced in RF23. This proceeding was the first inclusion of the FWH Bridging  
5 Strategy expenditures as PERC O&M.

6

7 **Q182. What was the rationale for the Circulating Water Pump (CWP)**  
8 **refurbishments shown on line 27 of Exhibit A-13, Schedule C5.16, page 1?**

9 A182. The Fermi 2 Circulating Water Pumps (CWP) and motors require refurbishment  
10 approximately every 10 years to ensure reliable operation. Fermi 2 Power Plant has  
11 five CWPs, each driven by a 5000-horsepower motor, that supply the driving force  
12 for the Fermi 2 Circulating Water System. In general, Fermi 2 Power Plant only  
13 requires four of the five CWPs to be at full-power operations during the cooler  
14 months of October – April. It's during this time that DTE Electric can remove a  
15 CWP from service, ship the pump and motor offsite for refurbishment, and then  
16 reinstall the pump and motor prior to the warmer months when all five CWPs are  
17 required for full-power operations. The CWP refurbishments were first included  
18 with the Case No. U-20162 PERC O&M Exhibit and has had updated project  
19 expenditures with subsequent rate case PERC O&M exhibits.

20

21 **Q183. What are the Total Nuclear Power Generation O&M expenses that you**  
22 **support for the projected test period ending December 31, 2026?**

23 A183. I support Total Nuclear Power Generation O&M expenses of \$160.0 million for the  
24 2026 projected test period as shown in Exhibit A-13, Schedule C5.3, page 1, line  
25 24, column (o). As I have discussed previously, these projected Total Operation

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1 and Maintenance expenses are required for the safe and reliable operation of Fermi  
2 2 for the projected test period. I consider these expenses to be prudent and  
3 reasonable.

4

5 **Nuclear Surcharge**

6 **Q184. Is the Company requesting a change to the Nuclear Surcharge?**

7 A184. Only with respect to inflation for the Site Security and Radiation Protection portion  
8 of the Nuclear Surcharge. The Company is proposing an updated Nuclear  
9 Surcharge based on the same approach approved by the Commission in Case Nos.  
10 U-17767, U-18014, U-18255, U-20162, U-20561, U-20836, U-21297, and U-  
11 21534 and depicted in Exhibit A-20, Schedule J1.

12

13 The Site Security and Radiation Protection portion of the surcharge has been  
14 updated to reflect 2023 historical expense adjusted for inflation on line 2. The  
15 inflation rate is supported by Witness Uzenski on Exhibit A-13, Schedule C5.15.

16

17 The Nuclear Decommissioning Funding portion of the surcharge shown on line 3  
18 is unchanged.

19

20 The Low Level Radioactive Waste (LLRW) Disposal Funding portion of the annual  
21 surcharge shown on line 4 is unchanged.

22

23 The resulting nuclear surcharge set forth in Company rates is supported by  
24 Company Witness Willis on Exhibit A-16, Schedule F6.

Line  
No.

1    **Q185. What is the Nuclear Surcharge that you support for the 12-month projected**  
2           **test period ending December 31, 2026?**

3    A185. I support the Proposed Nuclear Surcharge of \$39.4 million for the projected test  
4           period as shown in Exhibit A-20, Schedule J1, page 1, line 5, column (b); this  
5           represents a change of approximately \$0.6 million from the current authorized  
6           Nuclear Surcharge shown on line 6, column (b). The Proposed Nuclear Surcharge  
7           funds Fermi 2 site security, radiation protection, nuclear decommissioning and the  
8           disposal of LLRW; these activities are required for safe and secure operation of the  
9           Fermi 2 Power Plant for the 2026 projected test period. I consider the Proposed  
10          Nuclear Surcharge to be prudent and reasonable.

11

12   **Q186. Does this complete your direct testimony?**

13   A186. 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-21860

## QUALIFICATIONS

AND

## DIRECT TESTIMONY

OF

STEVEN B. AMBROSE

**DTE ELECTRIC COMPANY**  
**QUALIFICATIONS AND DIRECT TESTIMONY OF STEVEN B AMBROSE**

Line  
No.

1   **I Background and Qualifications**

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

3   A1.   My name is Steven B. Ambrose. My business address is One Energy Plaza, Detroit,  
4           Michigan, 48226. I am a Vice-President and the Chief Information Officer for DTE  
5           Energy (DTE).

6  
7   **Q2.   On whose behalf are you testifying?**

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

9  
10   **Q3.   What is your educational background?**

11   A3.   In 1991, I earned a Bachelor's degree in Business Administration from Bellevue  
12           College. In 2008, I earned a Master's degree in Business Administration with high  
13           distinction from the University of Michigan.

14  
15   **Q4.   What work experience do you have?**

16   A4.   I joined DTE Energy in 1998 and since that time have served in a variety of  
17           progressively more responsible information technology (IT) roles including the  
18           oversight of the Company's enterprise business systems, the IT operations of DTE  
19           Energy's non-utility affiliates, and the stewardship of the Company's IT strategy  
20           and enterprise architecture. In 2003, I was appointed Director of IT Process and  
21           Skills where I oversaw all of DTE's application development staff and  
22           methodologies and oversaw IT governance functions including its Project  
23           Management Office ("PMO"), quality management, asset utilization, workforce  
24           planning, and process management and metrics.

Line  
No.

1 I was appointed in 2009 to Director of Enterprise Performance Management  
2 (“EPM”) and Chief of Staff to the CEO, in which I was responsible for the oversight  
3 of corporate performance and coordinated various corporate-wide initiatives,  
4 including the development and roll-out of corporate priorities, vision, and mission  
5 materials, initiating committees to oversee each of the corporate priorities, and the  
6 company’s adoption of continuous improvement methodologies like Six Sigma and  
7 Hoshin Kanri, a management tool for continuous improvement. I was appointed to  
8 my current position in 2011.

9

10 **Q5. What are your current duties and responsibilities?**

11 A5. As a Vice-President and the Chief Information Officer for DTE Energy, I am  
12 responsible for securing, operating, and applying the Company’s information  
13 technology investments and assets toward achieving DTE’s strategic objectives.  
14 These objectives include, among other things, service and operational excellence,  
15 exceptional customer satisfaction, storm response excellence, and outstanding  
16 productivity.

17

18 **Q6. Do you hold any certifications or are you a member of any professional**  
19 **organizations?**

20 A6. I have maintained my active Project Management Professional (“PMP”)  
21 certification since 2001.

22

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

25 A7. No, I have not.



Line  
No.

1 **II Purpose of Testimony and Summary**

2 **Q8. What is the purpose of your direct testimony?**

3 A8. The purpose of my direct testimony is to:

4 1. Introduce DTE Electric's key drivers and strategy for Information Technology  
5 investments to support maintaining the security, reliability and resiliency, and  
6 affordability (or cost effectiveness) of the Company's provision of electric  
7 service to customers;

8 2. Describe the IT capital investment framework and planning process that drives  
9 the IT Organization's project prioritization and cost estimation processes;

10 3. Support the reasonableness of DTE Electric's IT capital expenditures in the  
11 amount of \$174.6 million for the historical test year ended December 31, 2023,  
12 \$331.7 million in the bridge period (for the 24 months ending December 31,  
13 2025), and \$204.9 million for the projected test period ending December 31,  
14 2026; and

15 4. Discuss the variance of actual 2023 capital spend compared to 2023 capital  
16 spend approved in the MPSC's Order dated January 23, 2025 in the Company's  
17 last rate case, Case No. U-21534, and explain projected differences in 2024 and  
18 2025 (as compared to Case No. U-21534) for projects that meet the requirement  
19 established in the MPSC's Order dated May 2, 2019 in Case No. U-20162.  
20

21 **Q9. How would you summarize your testimony?**

22 A9. Information Technology (IT) represents the systems, platforms, and applications  
23 that occupy an increasingly ubiquitous and critical position in modern utility  
24 operations. IT focuses on managing information and making it electronically  
25 accessible to users through information processing, networking, and cloud systems

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(while Operational Technology (OT) focuses on enabling communication to keep assets and systems operational). IT is continuously advancing and offering innovative and useful capabilities that DTE Electric can apply to the benefit of its customers. To successfully capture those capabilities, the Company must also continuously analyze and plan for how to maintain and modernize its systems in a manner that is cost-effective and delivers the promise of IT advancements for customers and the community. The IT investments presented in my direct testimony represent the Company's plan for this work, which has been developed with the purpose of continuing to provide secure, reliable, and affordable service to customers for years to come. My testimony also covers the Customer IT area previously discussed by Company Witness Hatsios in Case No. U-21534.

**Q10. How is your testimony organized?**

A10. My testimony consists of the following sections:

- Section I Background and Qualifications
- Section II Purpose of Testimony and Summary
- Section III IT Key Drivers and Investment Framework
- Section IV Investment Framework, Selection, and Approval
- Section V Cost Recovery Request and MPSC Requirements
- Section VI IT Capital Investment Details

A. Shared IT Portfolio

- 1. Information Technology for IT Sub-Portfolio
- 2. Information Protection Security Sub-Portfolio
- 3. Infrastructure Operations Sub-Portfolio
- 4. Enterprise Data Analytics (EDA) Sub-Portfolio

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No.

- 1                    5.        Innovations Sub-Portfolio
- 2                    B. Corporate Applications Portfolio
- 3                    C. Plant & Field Portfolio
- 4                    D. Customer IT Portfolio
- 5                    E. Projects Under \$250,000
- 6                    Section VII    Historical Spend Variance
- 7
- 8    **Q11. Are you sponsoring any exhibits in this proceeding?**
- 9    A11. Yes. I am sponsoring the following exhibits:
- | 10 | Exhibit | Schedule | Description                                             |
|----|---------|----------|---------------------------------------------------------|
| 11 | A-12    | B5.7     | Projected Capital Expenditures - Information Technology |
| 12 | A-12    | B5.7.1   | Corporate Applications                                  |
| 13 | A-12    | B5.7.2   | Customer IT                                             |
| 14 | A-12    | B5.7.3   | This tab is not used in this rate case                  |
| 15 | A-12    | B5.7.4   | Plant & Field                                           |
| 16 | A-12    | B5.7.5   | Information Technology for IT (IT for IT)               |
| 17 | A-12    | B5.7.6   | Information Protection Security (IPS)                   |
| 18 | A-12    | B5.7.7   | Infrastructure Operations                               |
| 19 | A-12    | B5.7.8   | Enterprise Data Analytics                               |
| 20 | A-12    | B5.7.9   | Innovations                                             |
| 21 | A-24    | N1       | IT Business Cases – Executive Summaries                 |
| 22 | A-24    | N2       | Historical Spend Variance Summary                       |
| 23 | A-24    | N3       | IT Capital Investments with Additional Project Details  |
| 24 | A-24    | N5       | Digital Self-Service Call Volume Reduction              |
| 25 | A-24    | N7       | Error Free Communications (EFC) Capital Spend           |

Line  
No.

1           A-24       N8       2024-2025 Outage and EFC Channel Enhancements  
2           A-13       C5.13   Projected Operation and Maintenance Expenses -  
3                                   Information Technology  
4

5   **Q12. Were these exhibits prepared by you or under your direction?**

6   A12. Yes, they were.  
7

8   **III   IT Key Drivers and Investment Framework**

9   **Q13. Does the DTE IT Organization solely serve DTE Electric?**

10   A13. The IT Organization serves DTE Electric, DTE Gas, and the DTE Energy enterprise  
11       as a whole. It works with the DTE Electric business units to prioritize IT investment  
12       needs and develop IT solutions. Specifically, for DTE Electric, the IT Organization  
13       seeks to enable the Company to carry out its mission of providing safe, reliable,  
14       low-cost energy to customers. This objective is accomplished through the  
15       development of IT investment plans based on robust, data-based budgeting and  
16       planning, a rigorous project prioritization and cost estimation process, and  
17       appropriate metrics and measures that guide project implementation and cost  
18       management.  
19

20   **Q14. What are DTE Electric's key investment drivers for IT?**

21   A14. The Company's key IT investment drivers are (1) cybersecurity for grid reliability  
22       and customer protection, (2) reliability and resiliency of IT assets, and (3)  
23       affordability (or cost effectiveness). Each of these drivers is reflected through the  
24       prudent investments for which DTE Electric is seeking recovery in this case as

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1 detailed in Section VI below and in the Company's project selection and effective  
2 cost management processes and practices.

3

4 **Q15. What is the cybersecurity investment driver?**

5 A15. DTE Electric remains focused on improving the security of its assets, systems, and  
6 customer data from cyber threats. Cyberattacks on utilities can cause widespread  
7 blackouts, economic disruptions, and even weaken national defense, as energy  
8 companies operate within one of sixteen critical infrastructure sectors identified by  
9 the federal government "whose assets, systems, and networks, whether physical or  
10 virtual, are considered so vital to the United States that their incapacitation or  
11 destruction would have a debilitating effect on security, national economic security,  
12 national public health or safety, or any combination thereof."<sup>1</sup> As cyber threats  
13 continue to become more sophisticated over time, the Company must likewise  
14 continue to (1) mature its security protections to be prepared for ever-evolving  
15 threats, and (2) meticulously operate those protections to be ready to respond to  
16 threats as they arise. DTE Electric's cybersecurity investments align with the  
17 Company's security controls supported by National Institute of Standards and  
18 Technology (NIST) security standards and North American Electric Reliability  
19 Corporation Critical Infrastructure Protection (NERC CIP) reliability standards.

20

21 **Q16. What is the reliability and resiliency investment driver?**

22 A16. The Company's IT systems must operate continuously without interruption,  
23 particularly at those times when the grid is stressed and customers most need the

---

<sup>1</sup> Presidential Policy Directive (PPD) 21 (issued Feb. 12, 2013), available at [https://www.cisa.gov/sites/default/files/2023-01/ppd-21-critical-infrastructure-and-resilience-508\\_0.pdf](https://www.cisa.gov/sites/default/files/2023-01/ppd-21-critical-infrastructure-and-resilience-508_0.pdf) (identifying the energy sector as "uniquely critical due to the enabling functions [it] provide[s] across all critical infrastructure sectors").

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1 IT systems to function. During the most significant storms and the hottest summer  
2 days, customers need the DTE Electric customer channels (e.g., mobile app,  
3 website, etc.) to reliably provide the most current information and Company crews  
4 need IT systems to function reliably to restore power. This investment driver results  
5 in (1) initial investments in IT systems and solutions and (2) constant maintenance  
6 of those systems and solutions to ensure reliability and resiliency. Ongoing  
7 investment in systems, hardware, software, and component maintenance must  
8 occur to keep IT assets healthy and ensure their reliability and resiliency for  
9 customers.

10

11 **Q17. What is the affordability investment driver?**

12 A17. DTE Electric strives to invest in ways that optimizes the cost effectiveness of IT  
13 investments for the benefit of customers in two primary ways. First, the Company  
14 employs a number of strategies to ensure investments are made at the most  
15 economical price point. These strategies include, for example, competitive bidding,  
16 consideration of alternatives, and maximization of investment value by considering  
17 economies of scale and cost-effective maintenance. Second, the Company achieves  
18 economic feasibility by using IT assets to improve internal processes and asset  
19 efficiencies to prevent outages, repairs, and replacements.

20

21 **Q18. How do DTE Electric's key IT investment drivers translate into IT**  
22 **investments?**

23 A18. The Company's IT investments, as driven by these key drivers, can be viewed  
24 through the lenses of Portfolios and Categories.

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1 The four IT investment Portfolios generally align with DTE Electric's business  
2 units and thus indicate the part of the Company for which the investment will bring  
3 value:

4 (1) Shared IT, and its Sub-Portfolios:

5 (a) Information Technology for IT (IT for IT),

6 (b) Information Protection Security (IPS),

7 (c) Infrastructure Operations,

8 (d) Enterprise Data Analytics, and

9 (e) Innovations;

10 (2) Corporate Applications;

11 (3) Plant & Field; and

12 (4) Customer IT.

13

14 Within each IT investment Portfolio and Sub-Portfolio, the Company organizes and  
15 plans its IT investments using five Categories. Each category corresponds to an IT  
16 investment purpose – the nature of the value brought to the Portfolio by that  
17 investment. In certain cases, an investment may apply to multiple Categories, in  
18 which case DTE Electric categorizes the project according to the category that  
19 represents the project's most prominent purpose and features:

20 (1) Regulatory/Compliance;

21 (2) Sustainment;

22 (3) Return-to-Health;

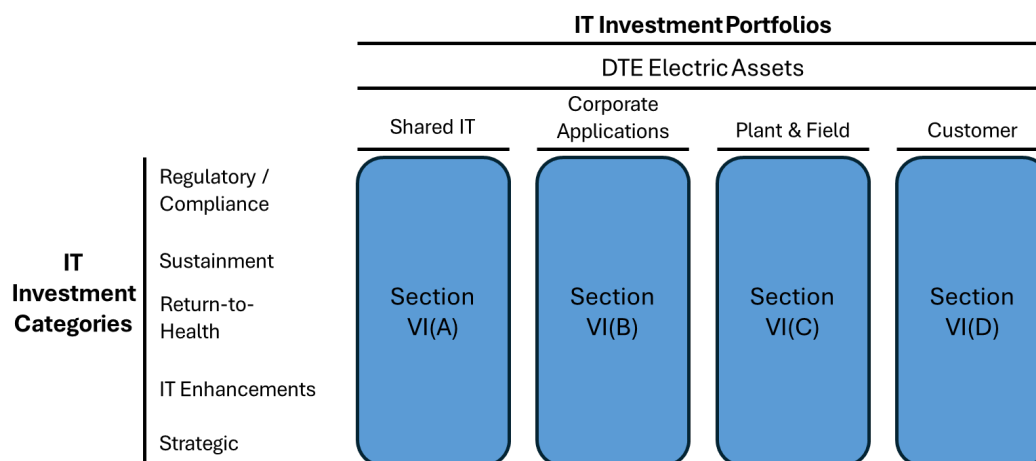
23 (4) IT Enhancements; and

24 (5) Strategic.

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The interplay between the Portfolios and Categories is illustrated by Figure 1 . As I note above, a particular investment may have components or aspects that fall into more than one category. For purposes of my testimony, investments are organized according to the primary category to which they relate. In the remainder of this section, I describe each of the Portfolios and Categories of IT investments.

Figure 1 IT Investment Portfolios and Categories



## IT Portfolios

### Q19. What is included in the Shared IT Portfolio?

A19. The Shared IT Portfolio supports the DTE Energy enterprise by establishing the IT foundation required by the other Portfolios. The investments within the Shared IT Portfolio are presented in Section VI.A of my testimony. The Shared IT Portfolio encompasses five Sub-Portfolios:

1. Information Technology for IT (IT for IT) – The IT for IT Sub-Portfolio consists of capital investments made for the enterprise as a whole or that enable the functioning of the IT Organization in support of the Company. These investments represent initiatives that either are more periodic in nature than



Line  
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1 ongoing year-over-year asset replacements or bring significant new capabilities  
2 to the IT department. See Section VI.A.1.

3

4 2. Information Protection Security (IPS) – IPS Sub-Portfolio investments focus on  
5 the reliability of cybersecurity infrastructure and improving the Company’s  
6 overall cybersecurity posture in IT and Operational Technology (OT). The  
7 Company seeks to improve the combined risk posture across IT and OT by  
8 implementing a unified approach to security governance, covering both areas  
9 while recognizing that cybersecurity requirements and risk appetite may differ  
10 across the two domains. DTE’s cybersecurity investments use a balanced  
11 approach to keep cybersecurity infrastructure healthy and appropriately updated  
12 to address emerging threats, while the Company increases its focus on maturing  
13 cybersecurity controls in the OT domain. See Section VI.A.2.

14

15 3. Infrastructure Operations – The Infrastructure Operations Sub-Portfolio is  
16 responsible for the design, implementation, and secure operation of the  
17 Company’s overall IT Infrastructure. This includes all the Company’s physical  
18 IT assets (i.e., datacenters, servers, computers, network devices, and the  
19 licensed software that supports those assets). This Sub-Portfolio is responsible  
20 for the day-to-day operation of these assets, the overall health of the assets  
21 (including operational growth, capacity, and availability standards), and from a  
22 project perspective, the enhancement of these assets to meet project  
23 requirements. See Section VI.A.3.

Line  
No.

1 4. Enterprise Data Analytics (EDA) – In this Sub-Portfolio, the Company  
2 continues to build a cloud-based and on-premise data platform to enable  
3 analytics to drive business value. This requires a data platform for data storage  
4 and processing as well as software to manage the data and usage. To support  
5 DTE’s data users, the Company created the EDA team to enable the  
6 infrastructure, build integrations to source systems, and subsequently organize,  
7 describe, and document the data available on the platform. EDA’s mission is to  
8 dependably deliver timely, secure, high-quality data to business partners  
9 throughout the Company. See Section VI.A.4.

10

11 5. Innovations – In this Sub-Portfolio, to address customer and business  
12 challenges that cannot be solved with traditional approaches, DTE applies  
13 innovation to deliver rapid value with shorter development cycles. The  
14 Company has proven the ability to boost reliability by expanding how it  
15 services and maintains its IT assets and accelerates access to decision-making  
16 tools for customer and employee use. See Section VI.A.5.

17

18 **Q20. What is included in the Corporate Applications Portfolio?**

19 A20. The Corporate Applications Portfolio encompasses investments in IT assets and  
20 applications used by the enterprise to execute critical internal business functions.  
21 This Portfolio supports enterprise business units including Human Resources,  
22 Finance and Controller, Legal, Supply Chain, and Fleet & Facilities. The  
23 investments within Corporate Applications span the investment Categories  
24 discussed further below, and the specific projects are detailed in Section VI.B of  
25 my testimony.

Line  
No.

1 **Q21. What is included in the Plant & Field Portfolio?**

2 A21. The Plant & Field Portfolio supports IT business systems used by the Company to  
3 operate and maintain its plants (e.g., Energy Supply (ENS), Generation  
4 Optimization (GenOpts), and the Company's nuclear generating facility, Fermi2)  
5 and its field force (e.g., Distribution Operations (DO)). The business systems  
6 supported by this Portfolio include core technologies, such as the Work and Asset  
7 Management system, which tracks plant maintenance work, that are utilized across  
8 all of these organizations and department-focused systems such as Outage  
9 Management, equipment Tagging, Mapping, and other similar technologies. The  
10 investments in the Plant & Field Portfolio cover various categories, which are  
11 discussed below. Specific projects are detailed in Section VI.C of my testimony.

12

13 **Q22. What is included in the Customer IT Portfolio?**

14 A22. The Customer IT Portfolio comprises key systems integrating with the Company's  
15 SAP Customer Relationship and Billing (CR&B) platform or other significant  
16 Customer systems like those that support the Error Free Communication Initiative.  
17 Investments in the Customer Service Portfolio directly impact the Company's  
18 interactions with customers. The investments within the Customer IT Portfolio span  
19 the investment Categories discussed further below, and the specific projects are  
20 detailed in Section VI.D of my direct testimony.

21

22 **IT Investment Categories**

23 **Q23. How does the Company determine the category for each proposed IT**  
24 **investment?**

Line  
No.

1 A23. The Company has established specific criteria for each category that I detail below.  
2 As I explain in Section IV of my testimony, the Company has continued to review  
3 and refine the criteria for each category to ensure the projects are accurately  
4 categorized. These refinements facilitate the project selection and prioritization  
5 process outlined in Section IV and further advance the Company's key investment  
6 drivers to the benefit of customers.

7

8 As part of their categorization, projects are identified as discretionary or non-  
9 discretionary. Non-discretionary investments fall into the Regulatory/Compliance  
10 Sustainment, and Return-to-Health Categories and represent projects that are  
11 required by either regulatory directive, compliance standard, or operational  
12 requirements to maintain a functioning utility system. The Company considers  
13 them as "must-do" investments and does not have a choice regarding whether to  
14 make these investments and continue to be able to provide safe, reliable service.  
15 Discretionary projects do not qualify as non-discretionary and have been identified  
16 as needed to further ensure cybersecurity, support power system reliability and  
17 resiliency, or contribute to operational efficiencies. During the past year, the  
18 Company has refined the criteria for qualifications for each of these Categories, as  
19 discussed further in Section IV below.

20

21 **Q24. What is included in the Regulatory/Compliance category of IT investment?**

22 A24. Investments captured in the Regulatory/Compliance category represent  
23 nondiscretionary spending that is required to meet and maintain compliance with  
24 current or anticipated regulatory and compliance standards within the next two  
25 years. In addition to the MPSC, other regulatory agencies that can trigger

Line  
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1 Regulatory/Compliance projects include, but are not limited to, the North American  
2 Electric Reliability Corp (NERC), the Federal Energy Regulatory Commission  
3 (FERC), the Nuclear Regulatory Commission (NRC), and the Transportation  
4 Security Administration's (TSA) Oil and Natural Gas Pipeline Security standards.  
5 Investments within this category generally include system patching, security  
6 configuration of assets, and management of evidence, audit data, and log files in  
7 support of ensuring customer and employee security and the reliability and  
8 resiliency of IT assets.

9

10 **Q25. What is included in the Sustainment category?**

11 A25. The Sustainment category represents non-discretionary spend required to maintain  
12 existing applications that are critical to the Company's day-to-day operations.  
13 Capital spend in this category includes, for example, functional periodic releases,  
14 infrastructure upgrades (adaptive maintenance), performance tuning, and data  
15 storage enhancements to ensure the reliability and resilience of IT assets.

16

17 **Q26. What is included in the Return-to-Health category?**

18 A26. The Return-to-Health category represents non-discretionary spend to update or  
19 replace hardware and software systems that are nearing End of Life (EOL),  
20 meaning they are reaching the end of their serviceable lives and, without update or  
21 replacement, will eventually cease to function and adversely impact the Company's  
22 Operations. An example is replacing end-of-life network devices, such as data-  
23 center core switches and routers, with new components to enhance the connection  
24 bandwidth between the Company's data centers.

Line  
No.

1 **Q27. What is included in the IT Enhancements category?**

2 A27. The IT Enhancements category covers discretionary investments that make  
3 incremental improvements to existing systems to further cybersecurity, reliability  
4 and resilience, or affordability (or cost effectiveness). These investments include  
5 adding new features, expanding capabilities on existing platforms, consolidating  
6 redundant systems, and enhancing infrastructure for improved operational  
7 reliability. IT Enhancement investments may also include technology solutions  
8 designed to automate existing manual processes, support regulatory/compliance  
9 requirements, and drive efficiency in current processes.

10

11 **Q28. What is included in the Strategic category?**

12 A28. While the IT Enhancement category generally focuses on incremental  
13 improvements to existing systems, investments falling into the Strategic category  
14 are generally linked to the introduction of new value-generating assets or the  
15 enablement of new capabilities. This category includes cases where existing  
16 applications or assets are at risk of becoming unsupported in the near future, and  
17 multi-year programs that deliver new scope or functionality on an annual basis. An  
18 example is the implementation of a purpose-built Storm Data Lakehouse that will  
19 provide an efficient, unified access layer for storm datasets to address storm  
20 analytics needs and provide situational awareness of storm restoration efforts.

21

#### 22 **IV Investment Framework, Selection, and Approval**

23 **Q29. How would you describe DTE's IT investment selection and approval process?**

24 A29. The Company's investment selection and cost estimation processes are robust and  
25 comparable to industry best practices and standards. DTE continuously seeks ways

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1 to refine these processes in the interest of making the best project selection and cost  
2 estimation decisions for customers and has made several such enhancements since  
3 Case No. U-21534, as I discuss later in this section of my testimony.

4

5 **Q30. What is DTE's approach to IT investment identification and selection?**

6 A30. DTE's approach to IT investment identification and selection leverages its robust  
7 budgeting and planning process, recognizing that the Company operates on a  
8 limited capital budget. In any given year there is more work that has been identified  
9 as needed than the IT Organization can execute due to capital budget constraints.  
10 As such, the Company may need to adjust or re-sequence a scheduled high priority  
11 item based on other emerging needs that are of even higher priority.

12

13 In addition, as DTE considers cybersecurity, reliability and resiliency, and  
14 affordability drivers of its IT investments, it must also continue to effectively  
15 optimize the life cycle of those investments. The Company is always seeking to  
16 refresh, replace, and maintain IT investments in a manner that supports these  
17 drivers. The Company successfully manages IT asset life cycles by considering  
18 thresholds for tolerance in business processes, manual work arounds, and customer  
19 needs. For example, a field crew member whose laptop is at end of life may receive  
20 a replacement before a System Operations Center (SOC) crew member with a  
21 similarly aged machine, since the field crew may have less flexibility to borrow  
22 another machine or apply a workaround.

23

24 DTE is consistently working to strengthen its estimation and qualification  
25 processes. Since filing Case No. U-21534, the Company reassessed these processes

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1 and made enhancements, discussed below, that have enabled the Company to take  
2 a more proactive, comprehensive view of project selection prior to approval and  
3 execution. This refinement has strengthened the Company's overall approach for  
4 planning, prioritization, and resource allocation for IT investments.

5  
6 **Q31. What process does the Company use to identify and prioritize IT investment**  
7 **projects?**

8 A31. DTE Energy develops and refines its investment strategies and plans across the  
9 enterprise through its Annual Planning Cycle (APC). The APC process determines  
10 where specific, targeted investments will be focused based on near-term priorities  
11 and current conditions over a rolling three-year time frame. The APC process as  
12 applied to the IT Organization is detailed in Figure 2, below. This process is aligned  
13 with the enterprise-wide APC process, with refinements as I discuss later in this  
14 section.

15 Figure 2 DTE IT APC Cadence



16  
17 The IT APC activities occur in phases. The N+2 Planning phase involves review of  
18 capital investments two years out from the investment planning year (N). In the  
19 N+1 Planning phase, final investments are approved and appropriated for  
20 investments one year out from the investment planning year (N).



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1 **Q32. What occurs in the “Submitted” state for a capital investment within the IT**  
2 **APC process?**

3 A32. In the “Submitted” state, for each capital investment, the business unit submits  
4 detailed project scope that identifies the opportunity, functionality, or capability  
5 sought with the requested investment, along with its value proposition, related key  
6 output measures, key objectives, alternative analysis, and cost estimate.

7  
8 **Q33. What happens in the “Screening” state for a capital investment within the IT**  
9 **APC process?**

10 A33. Beginning with the 2025 investment planning cycle, in the “Screening” state,  
11 requested capital investments undergo a comprehensive review of their alignment  
12 with the Company’s key investment drivers of (1) cybersecurity for grid reliability  
13 and customer protection, (2) reliability and resiliency of IT assets, and (3)  
14 affordability (or economic feasibility). All capital investments, non-discretionary  
15 and discretionary, also undergo assessments for alignment with Cloud and Capital  
16 Accounting Policy, Supply Chain, Architecture, Security, and Compliance. In  
17 addition, discretionary projects are evaluated through the Project Prioritization  
18 Score (PPS) assessment.

19  
20 **Q34. What is the PPS model used to evaluate discretionary project benefits.**

21 A34. Beginning with the 2023 investment planning cycle, the Company developed the  
22 Project Prioritization Score (PPS) model as a framework to evaluate, score, and  
23 prioritize discretionary projects. The PPS is used as a standardized scoring and  
24 ranking methodology to bring consistency to DTE’s assessment of discretionary  
25 projects across multiple IT investment Portfolios. Commencing with the 2025

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investment planning cycle, the Company refined the PPS scoring criteria to align with its key investment drivers, as indicated in Table 1.

**Table 1 Project Prioritization Score Criteria**

|                     | Strategic Fit       |                     |                     | Financial Impact |              | Operational Impact      |                        |
|---------------------|---------------------|---------------------|---------------------|------------------|--------------|-------------------------|------------------------|
| Selection Criteria  | Strategic Alignment | Customer Experience | Employee Engagement | Affordability    | Cost Benefit | Operational Reliability | Fundamental Capability |
| Weight (total=100%) | 10 %                | 15%                 | 10%                 | 30%              | 10%          | 20%                     | 5%                     |

**Q35. What happens in the “Qualified” state for a capital investment within the IT APC process?**

A35. In the “Qualified” state of the IT APC process, the Company utilizes PPS scores and execution capacity to prioritize the capital investment. This ensures that investments with the highest return on investments (ROI) and those that align with the key IT drivers constitute the IT investment plan. Beginning in 2025, the Company is requiring that all projects that are Qualified have a level 2 cost estimate. Level 2 cost estimates are used for detailed project control and near-final decision making, with an accuracy range of -15% to +20%. The Qualified projects meeting these criteria then constitute the IT investment plan proposed for approval.

**Q36. What is the next step in the IT APC process?**

A36. In the “TIC Approved” state, the IT investment plan is recommended for review and approval by the Company’s Technology Investment Committee (TIC), which is composed of executives from across DTE.

Line  
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1   **Q37. What are the next steps that occur within the APC process before the project**  
2       **is approved?**

3   A37. Upon review and approval by the TIC, projects are promoted to the “Detailed  
4       Estimate” state, in which a level 3 estimate is developed that has an accuracy range  
5       of -10% to +15%. DTE employs a detailed cost estimation process to evaluate  
6       proposed IT capital projects. Through this process, the Company focuses on  
7       ensuring certainty in project cost estimation.

8  
9       Upon completion of the level 3 estimates in the “Detailed Estimates” state, these  
10      projects are then promoted to the “Approval Workflow” state for stakeholder  
11      approval. Lastly, capital dollars appropriation is completed in the “Approved” state  
12      to begin execution.

13

14   **Q38. How does the Company explore and consider alternate solutions for each**  
15       **project in the IT APC process?**

16   A38. For each new investment represented in my testimony, the Company has considered  
17       the following standard alternatives:

- 18       • Maintain status quo: forego or delay the investment; “do nothing” within the  
19       instant rate case period and defer the activity to a future period;
- 20       • Manual: revert to a manual process rather than updating or replacing the existing  
21       system, where applicable or possible; and
- 22       • Look outside: look outside of the platform for an alternative to implement in  
23       place of the existing solution that has an advantage for customers or the business  
24       unit.

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1 These alternatives are addressed where applicable in Section VI of my testimony  
2 and in the executive summaries for the IT investments provided as part of Exhibit  
3 A-24, Schedule N1 IT Business Cases – Executive Summaries.

4  
5 **Q39. Are you familiar with arguments made by Staff and intervenors in previous**  
6 **cases, and with discussions in previous Commission orders, regarding**  
7 **applying AACE cost estimates to the Company's IT investments?**

8 A39. Yes, I am.

9  
10 **Q40. Do you agree with the application of AACE cost estimate classifications with**  
11 **regard to DTE Electric IT capital expenditures?**

12 A40. No, please refer to the testimony of Company Witness Ludlow for discussion of  
13 utilizing AACE class cost estimation when evaluating IT investments. Also, as  
14 discussed by Company Witness Ludlow, the Commission should also consider the  
15 fact that there is a range of uncertainty in a project which does not constitute a  
16 reason for disallowance.

17  
18 **V. Cost Recovery Request and MPSC Requirements**

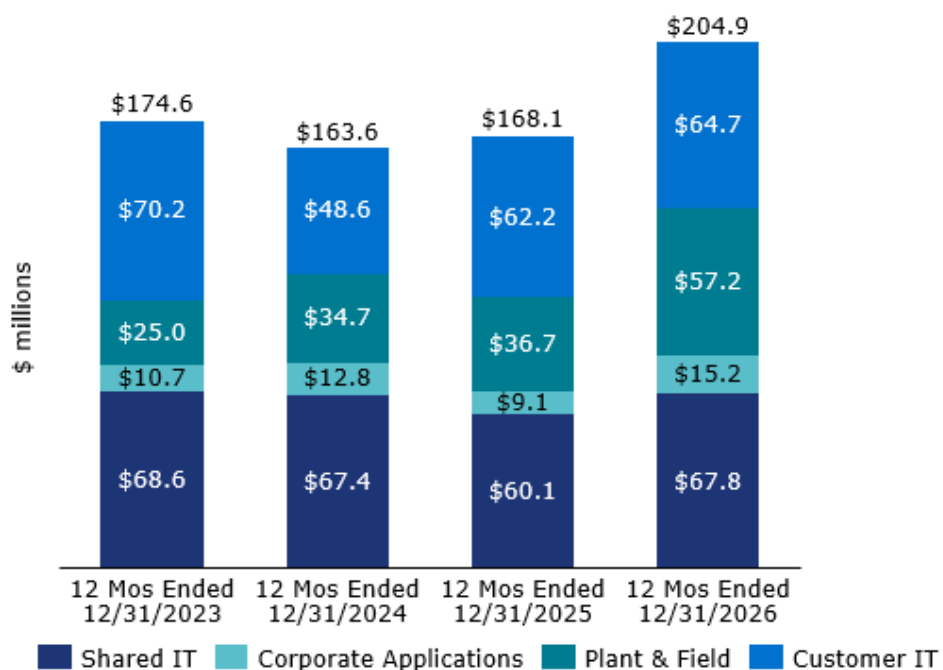
19 **Q41. What level of IT investment capital does your testimony support?**

20 A41. My testimony supports DTE Electric IT capital expenditures in the amount of  
21 \$174.6 million for the historical test year ended December 31, 2023, \$331.7 million  
22 in the bridge period (for the 24 months ending December 31, 2025), and \$204.9  
23 million for the projected test period ending December 31, 2026. These amounts are  
24 represented graphically in Figure 3, below.

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Figure 3 DTE Electric Capital Expenditure by Period



2

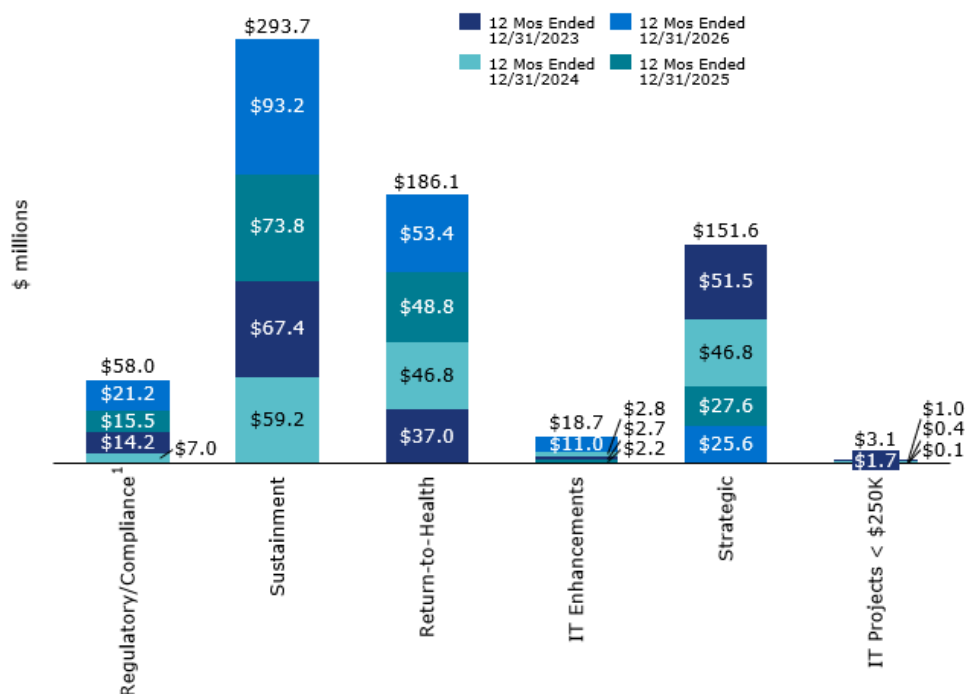
3 **Q42. How are these expenditures spread across the IT investment Categories?**

4 **A42.** See Figure 4, below, for a depiction of these expenditures by investment category.

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Figure 4 DTE Electric IT Capital Expenditure by category



2

3 **Q43. What are the Commission's requirements as specified in previous orders**  
 4 **regarding the information to be provided in support of IT projects proposed**  
 5 **for cost recovery?**

6 A43. Historically, in Case No. U-18238, the Commission set forth seven filing  
 7 requirements directly related to the highest cost Top 25 IT and OT projects in the  
 8 projected test year. These requirements can be found in the Part III filing. The Part  
 9 III filing requirements were further revised in the Commission's order dated May  
 10 18, 2023, in the same proceeding, to include additional information in a spreadsheet  
 11 and readable PDF format. In the Commission's order in Case No. U-20162 dated  
 12 May 2, 2019, the MPSC instructed the Company to provide a breakdown of both  
 13 O&M and Capital cost into two or three Sub-Categories and adopted nine additional

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1 requirements for projects greater than \$0.5 million addressing scope, schedule, cost,  
2 and alternatives. In the Commission's order in Case No. U-21297 dated December  
3 1, 2023, the Commission directed the Company to provide an exhibit outlining IT  
4 O&M spend. No new requirements were established in the Commission's final  
5 order in Case No. U-21534 dated January 23, 2025 ("Case No. U-21534 Final  
6 Order").

7  
8 The exhibits listed below have been developed to meet the aforementioned  
9 requirements and will be provided with the testimony:

- 10 • Exhibit A-12 Schedule B5.7 is a summary view of IT capital cost by Portfolio  
11 and investment category across the historical year (2023), bridge year (24  
12 months ending 12/31/2025), and projected test year (12 months ending  
13 12/31/2026) periods.
- 14 • Exhibits A-12 Schedules B5.7.1 through B5.7.9 present the capital spend in the  
15 historical, bridge, and projected test periods within each Portfolio. I have  
16 structured my testimony to address IT projects under the Portfolio they support,  
17 in the same order that the Portfolios and projects in these exhibits are presented,  
18 for each project more than \$250,000.
- 19 • Exhibit A-24 Schedule N1 presents the executive summaries for each business  
20 case associated with each project over \$250,000. Exhibit A-24 Schedule N1  
21 tracks to the same order of projects as Exhibit A-12 Schedules B5.7.1 through  
22 B5.7.9. I also provide the corresponding business cases for each project in my  
23 workpapers.
- 24 • Exhibit A-24 Schedule N3 provides a greater level of detail consistent with the  
25 format set forth in the rate case filing requirements issued on May 18, 2023 in

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1 Case No. U-18238. Each of these IT projects are presented by year and then in  
2 Portfolio and project order.

3 • All variance commentary provided within my testimony will reconcile to  
4 Exhibit A-12 Schedules B5.7 - B5.7.9. Where additional recovery is being  
5 requested, please refer to Exhibit A-24 Schedule N2.

6 • The IT O&M spend information required in Case No. U-21297 is included as  
7 Exhibit U-21860 IT O&M Exhibit A-13 Schedule C5.13. The 'A&G  
8 Capitalized' on line 7 reflects the transfer (allocation) of A&G costs to capital  
9 as an overhead. The amount of A&G transferred (allocated) is based on the  
10 percentage of total direct labor charged to capital.

11

12 **Q44. What are the capital cost and the corresponding O&M costs for IT Projects?**

13 A44. The capital costs reflected in Exhibit A-24, Schedule N-3 and Exhibit A-12  
14 Schedule B5.7 represent the portion of IT costs, including hardware costs, software  
15 costs, and software development costs, allowed to be capitalized in accordance with  
16 the Company's accounting policies. These policies define the scope and phases of  
17 a project that can be capitalized and the scope and phases of the project that should  
18 be expensed. According to these policies the O&M cost is considered cost-to-  
19 achieve (CTA). The O&M costs reflected in Exhibit A-24, Schedule N3 represent  
20 the total O&M cost-to-achieve for each project and are provided for informational  
21 purposes only.

22

23 **Q45. Can you provide a more detailed description of other IT O&M cost?**

24 A45. Yes. In addition to CTA expense, the Company's IT operating expense, as shown  
25 on Exhibit A-13, Schedule C5.13, includes operational labor support (Base



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1 Operate) and software maintenance cost (License Management & Maintenance).  
2 The IT operational labor support cost represents IT resources that support hardware  
3 and software defect remediation (e.g., Office 365 not working as expected,  
4 Password Reset Support, multi-factor authentication (MFA) failure and access  
5 requests), business support services (e.g., IT Help Desk, Data Center Operation),  
6 and IT administration. Commercial software maintenance and support cost  
7 represents IT O&M expense, including software maintenance and license for use  
8 fees, for on premise and cloud solutions for certain software contracts.

9

10 **Q46. Can you explain the normalization adjustments reflected in column (c) on**  
11 **Exhibit A-13, Schedule C5.13?**

12 A46. Column (c) on line 8 is an O&M increase of \$10.0 million for the normalization of  
13 temporary cost reductions in 2023.

14

15 **Q47. What makes up the \$10.0 million of temporary cost reductions in 2023?**

16 A47. The details are listed in footnote 1 of Exhibit A-13, Schedule C5.13 and include  
17 \$1.6 million related to one-time credit from Accenture, a temporary change in  
18 project sequencing for \$3.9 million, \$2.0 million due to delayed penetration testing  
19 and auditing for Transportation Security and Authority projects, and \$2.5 million  
20 of temporary reductions in IT Base operate expenses to delay non-critical IT  
21 work. These temporary reductions were taken to mitigate the financial challenges  
22 experienced by the Company in 2023 as further discussed by Company Witness  
23 Bruzzano and are not expected to recur in the projected test period.

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1 **Q48. What projected adjustments did you make to O&M as reflected in columns (e)**  
 2 **through (h)?**

3 A48. Increases based on the inflation rate (columns e, f, and g) were applied to the  
 4 adjusted historical test period expenses for the period January 2024 through  
 5 December 2026, as supported by Company Witness Uzenski. In addition, labor  
 6 was reduced by \$2.5 million on line 3, column (h), for savings from the Voluntary  
 7 Separation Incentive Plan (VSIP) supported by Company Witness Leslie. Line 4  
 8 reflects an increase of \$9.7 million for software license fees, as discussed by  
 9 Company Witness Uzenski. Line 5 reflects an increase of \$5.7 million for CTA  
 10 costs related to an increase in 2026 IT projects, as described in Exhibit A-24,  
 11 Schedule N3.

12

13 **Q49. Are there any IT projects that have already been approved for cost recovery**  
 14 **in previous rate cases with no additional spend being requested in the instant**  
 15 **case?**

16 A49. Yes, the projects listed in Table 2 were approved for cost recovery in Case Nos.  
 17 U-21297 and 21534 and are not described further in this testimony.

18

**Table 2 IT Projects Approved in U-21297 & U-21534**

19

| Project Name                                              | Portfolio                               | Category  | U-21860<br>Exhibit<br>Reference | Previous<br>Exhibit<br>Reference |
|-----------------------------------------------------------|-----------------------------------------|-----------|---------------------------------|----------------------------------|
| Azure Active<br>Directory<br>Federation<br>Implementation | Information<br>Protection &<br>Security | Strategic | Line 13,<br>A-12<br>B5.7.6      | Line 10,<br>A-12<br>B5.7.6       |
| Enterprise<br>Mobility<br>Management                      | Information<br>Protection &<br>Security | Strategic | Line 17,<br>A-12<br>B5.7.6      | Line 12,<br>A-12<br>B5.7.6       |

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No.

**S. B. AMBROSE**

U-21860

| <b>Project Name</b>                                                 | <b>Portfolio</b>                  | <b>Category</b>  | <b>U-21860 Exhibit Reference</b> | <b>Previous Exhibit Reference</b> |
|---------------------------------------------------------------------|-----------------------------------|------------------|----------------------------------|-----------------------------------|
| Recovery Manager for AD- Disaster Recovery Edition                  | Information Protection & Security | Strategic        | Line 19, A-12 B5.7.6             | Line 16, A-12 B5.7.6              |
| Data Power Replacements                                             | Infrastructure Operations         | Strategic        | Line 37, A-12 B5.7.7             | Line 37, A-12 B5.7.7              |
| Enterprise Monitoring Strategy Implementation                       | Infrastructure Operations         | Strategic        | Line 40, A-12 B5.7.7             | Line 42, A-12 B5.7.7              |
| External Secure File Transfer Replacement                           | Infrastructure Operations         | Strategic        | Line 41, A-12 B5.7.7             | Line 43, A-12 B5.7.7              |
| Firewall Threat Protection                                          | Infrastructure Operations         | Strategic        | Line 42, A-12 B5.7.7             | Line 44, A-12 B5.7.7              |
| Core ERP Data Archiving                                             | Corporate Applications            | Return to Health | Line 12, A-12 B5.7.1             | Line 10, A-12 B5.7.1              |
| Organizational Management Optimization                              | Corporate Applications            | Strategic        | Line 17, A-12 B5.7.1             | Line 17, A-12 B5.7.1              |
| Application Portfolio Management – APM                              | Information Technology for IT     | Strategic        | Line 2, A-12 B5.7.5              | Line 3, A-12 B5.7.5               |
| Supervisory Control and Data Acquisition (SCADA) System Improvement | Plant & Field                     | Sustainment      | Line 16, A-12 B5.7.4             | Line 15, A-12 B5.7.4              |
| Meter Data Management (MDM) Consolidation                           | Plant & Field                     | Return to Health | Line 29, A-12 B5.7.4             | Line 25, A-12 B5.7.4              |
| Plant & Field Document Repository                                   | Plant & Field                     | Return to Health | Line 31, A-12 B5.7.4             | Line 27, A-12 B5.7.4              |

Line  
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**S. B. AMBROSE**

U-21860

| <b>Project Name</b>                                                    | <b>Portfolio</b> | <b>Category</b>         | <b>U-21860<br/>Exhibit<br/>Reference</b> | <b>Previous<br/>Exhibit<br/>Reference</b> |
|------------------------------------------------------------------------|------------------|-------------------------|------------------------------------------|-------------------------------------------|
| Replace DO Lines - SOC Radio                                           | Plant & Field    | Return to Health        | Line 32,<br>A-12<br>B5.7.4               | Line 28,<br>A-12<br>B5.7.4                |
| Field Service Management-ClickSoft for EFO (Electric Field Operations) | Plant & Field    | Strategic               | Line 35,<br>A-12<br>B5.7.4               | Line 31,<br>A-12<br>B5.7.4                |
| Maximo HSE Support                                                     | Plant & Field    | Strategic               | Line 38,<br>A-12<br>B5.7.4               | Line 34,<br>A-12<br>B5.7.4                |
| Powerley Customer Platform Application Health                          | Customer Service | Sustainment             | Line 24,<br>A-12<br>B5.7.2               | Line 12,<br>A-12<br>B5.7.2                |
| Agency Web Site AGW Rebuild                                            | Customer Service | Return to Health        | Line 29,<br>A-12<br>B5.7.2               | Line 24,<br>A-12<br>B5.7.2                |
| Customer Experience Suite                                              | Customer Service | Return to Health        | Line 31,<br>A-12<br>B5.7.2               | Line 24,<br>A-12<br>B5.7.2                |
| Customer Service Infrastructure Landscape & Growth                     | Customer Service | Return to Health        | Line 32,<br>A-12<br>B5.7.2               | Line 20,<br>A-12<br>B5.7.2                |
| Migrate IVR to the Cloud                                               | Customer Service | Return to Health        | Line 35,<br>A-12<br>B5.7.2               | Line 24,<br>A-12<br>B5.7.2                |
| Time of Day                                                            | Customer Service | Regulatory / Compliance | Line 10,<br>A-12<br>B5.7.2               | Line 1, A-12 B5.7.3                       |
| Contact Center Enablement                                              | Customer Service | Strategic               | Line 46,<br>A-12<br>B5.7.2               | Line 30,<br>A-12<br>B5.7.3                |
| Customer Relationship and Billing Program Enhancement                  | Customer Service | IT Enhancement          | Line 41,<br>A-12<br>B5.7.2               | Line 21,<br>A-12<br>B5.7.3                |

Line  
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| Project Name                             | Portfolio        | Category                | U-21860 Exhibit Reference | Previous Exhibit Reference |
|------------------------------------------|------------------|-------------------------|---------------------------|----------------------------|
| IT Application Environments Enhancements | Customer Service | IT Enhancement          | Line 42, A-12 B5.7.2      | Line 22, A-12 B5.7.3       |
| PCI Compliance                           | Customer Service | Regulatory / Compliance | Line 7, A-12 B5.7.2       | Line 12, A-12 B5.7.3       |
| SIP in Call Center                       | Customer Service | Strategic               | Line 55, A-12 B5.7.2      | Line 45, A-12 B5.7.3       |

1 **VI. IT Capital Investment Details**

2 **Q50. What information is contained in this section of your testimony?**

3 A50. As noted above, the information provided in the Company's Part III submission  
4 provides a detailed overview of IT capital investments organized into the IT  
5 Portfolios and Categories that I discuss in my testimony. This section of my  
6 testimony provides summaries of each of those investments. Within the Portfolios,  
7 the investments are organized by the investment Categories and appear in the same  
8 order as they do in the corresponding capital Exhibit A-12 Schedules B5.7.1  
9 through B5.7.9. The business case executive summaries for these investments are  
10 provided in Exhibit A-24 Schedule N1.

11

12 **A. Shared IT**

13 **Q51. Please recall how the Shared IT Portfolio investments are organized.**

14 A51. The Shared IT Portfolio investments fall into one of five Sub-Portfolios: (a)  
15 Information Technology for IT; (b) Information Protection Security; (c)  
16 Infrastructure Operations; (d) Enterprise Data Analytics; and (e) Innovations.

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1 *1. Information Technology for Information Technology (IT for IT)*

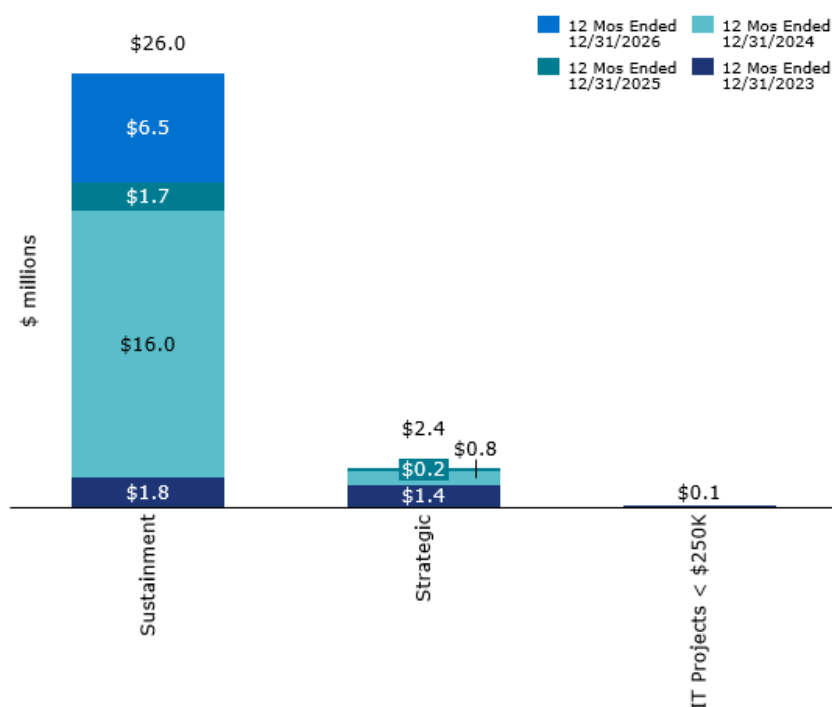
2 **Q52. What are the projected costs for investments in the IT for IT Sub-Portfolio?**

3 A52. As reflected on line 5 of Exhibit A-12 Schedule B5.7, page 1, capital expenditures  
4 for IT for IT total \$3.2 million for the historical test year ended December 31, 2023,  
5 \$18.7 million in the bridge period (for the 24 months ending December 31, 2025),  
6 and \$6.5 million for the projected test period ending December 31, 2026.

7

8 The synopses below generally provide the total spend for each line item the  
9 Company requests in this rate case and the details regarding breakout by historical  
10 period, projected bridge period, and projected test period, are each laid out in  
11 Exhibit A-12, Schedule B5.7.5, in columns d, g and h, respectively. Figure 5  
12 represents a high-level view of capital allocation within the Sub-Portfolio.

13 Figure 5 IT for IT investment



Line  
No.

1                    *a) Sustainment*

2

3    **Q53. Please explain the IT for IT Sub-Portfolio investment in the Sustainment**  
4                    **category.**

5    A53. The Company will invest \$24.2 million in the Sustainment category over the 36  
6                    months ending December 31, 2026, and has a historical spend of \$1.8 million in  
7                    2023, as shown on line 1 of Exhibit A-12, Schedule B5.7.5.

8

9                    (1) IT for IT Application Health

10                  The Company is seeking recovery for \$24.2 million in the IT for IT Application  
11                  Health project over the 36 months ending December 31, 2026, and the historical  
12                  spend of \$1.8 million in 2023, as shown on line 1 of Exhibit A-12, Schedule B5.7.5.

13                  This project includes production upgrades for the IT Services Platform in 2022-  
14                  2026, including ServiceNow, GitHub, and Azure Dev Ops. Applications receive  
15                  support provided by the vendor and regular upgrades to mitigate security  
16                  vulnerabilities. Yearly, the Company completes version upgrades (two annually for  
17                  ServiceNow and as made available by providing vendors for other applications).  
18                  This project enhances workflows to improve efficiency, adds new items to the  
19                  service catalog to take advantage of the ServiceNow solution to improve efficiency,  
20                  enables automations, extends discovery and event management to reduce  
21                  unplanned outages, and manages vulnerability identification and remediation.  
22                  ServiceNow is essential to the Company's IT governance and control and a critical  
23                  tool for supporting Sarbanes-Oxley (SOX) and PCI testing.

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1 The Company reports a variance of \$3.6 million more for the 36 months ending  
2 December 31, 2025, than was approved in Case No. U-21534 primarily due to a  
3 10% disallowance in 2023 and 20% disallowance in 2024 and 2025 per the Case  
4 No. U-21534 Final Order. See Exhibit A-24, Schedule N3 Lines 138 - 141 for  
5 additional project details.

6

7 *b) Strategic*

8 **Q54. Please describe the IT for IT Sub-Portfolio investment in the Strategic**  
9 **category.**

10 A54. The Company is seeking recovery for \$1.0 million in the Strategic category over  
11 the 24 months ending December 31, 2025, and the historical spend of \$1.4 million  
12 in 2023 as shown in lines 2 to 4 of the Capital Expenditures - Exhibit A-12,  
13 Schedule B5.7.5. These investments are described below:

14

15 (1) IT Service Management Tool

16 The Company is seeking recovery for \$0.4 million in the IT Service Management  
17 Tool project over the 12 months ending December 31, 2024, and the historical  
18 spend of \$1.0 million in 2023, as shown on line 3 of Exhibit A-12, Schedule B5.7.5.

19

20 The Service Management Tool includes modules for IT Planning, Support,  
21 Delivery, Security and Infrastructure that will support improved IT customer  
22 service. The phases of this investment include expansion of current capabilities  
23 around Vulnerability Management for Security, Governance Risk and Compliance,  
24 and Annual Investment Planning Process and asset management. The Company  
25 reports a variance of \$0.9 million more in the 12 months ending December 31,



Line  
No.

1 2024, than was approved in Case No. U-21534. Of this amount, \$0.1 million is due  
2 to a 10% disallowance in 2023 as directed by the U-21534 Final Order and the  
3 remaining \$0.8 million is for implementation of an additional service management  
4 tool, “Cutover,” which provided the capability to manage IT deployment  
5 playbooks. The project timeline has also been extended into 2024 to accommodate  
6 this additional scope. See Exhibit A-24, Schedule N3 Lines 144, 145 for additional  
7 project details.

8

9 (2) QMS Central Repository

10 The Company is seeking recovery for \$0.5 million in the Quality Management  
11 Systems (QMS) Central Repository project over the 24 months ending December  
12 31, 2025, as shown on line 4 of Exhibit A-12, Schedule B5.7.5.

13

14 Quality Management Systems enable businesses to consistently apply quality  
15 processes that provide services that meet customer expectations and regulatory  
16 requirements. This is core to the implementation of the ISO 9001-2015<sup>2</sup> standards  
17 in the DTE IT organization. The QMS repository will be the single source of all  
18 ITS policies, procedures, processes, and supporting documentation. This project  
19 will include the development of an automated QMS repository which will include  
20 building a workflow to support ISO 9001 audit requirements. The QMS central  
21 repository will enable the IT organization to consistently apply quality processes to  
22 provide services that meet customer expectations and regulatory requirements. See  
23 Exhibit A-24, Schedule N3 lines 146, 147 for additional project details.

---

<sup>2</sup> ISO 9001:2015: The international standard for quality management systems (QMS), providing a framework for organizations to improve their operations, enhance customer satisfaction, and demonstrate their ability to consistently provide products and services that meet requirements.

Line  
No.

1            *2. Information Protection & Security*

2    **Q55. What are the projected costs for investments in the Information Protection &**  
3        **Security (IPS) Sub-Portfolio?**

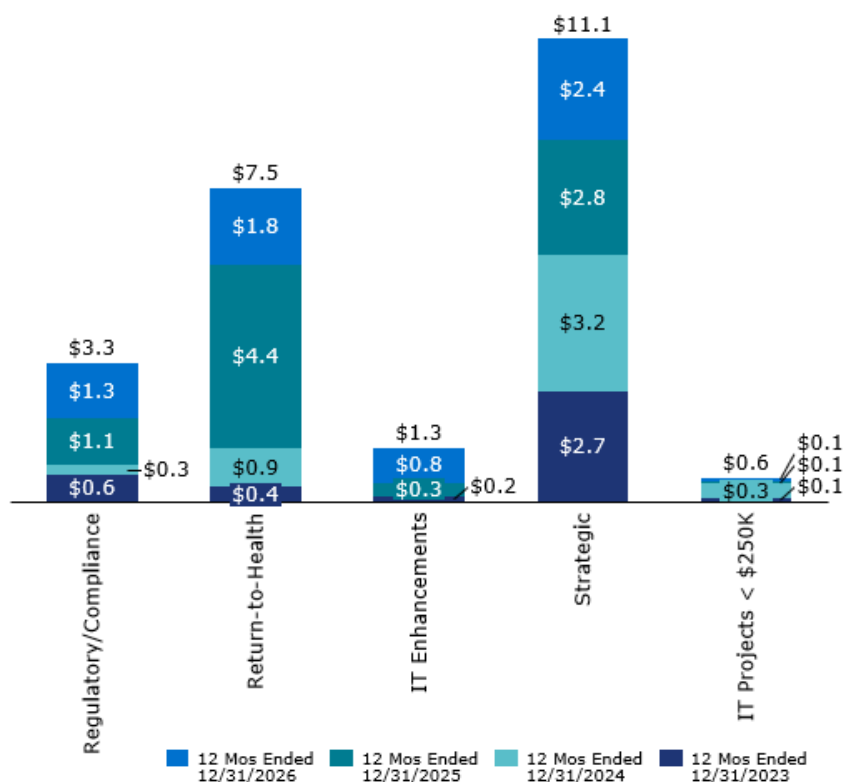
4    A55. As reflected on line 6 of Exhibit A-12 Schedule B5.7, page 1, capital expenditures  
5        for IPS total \$4 million for the historical period ended December 31, 2023, \$13.4  
6        million in the bridge period (for the 24 months ending December 31, 2025), and  
7        \$6.5 million for the projected test period ending December 31, 2026.

8  
9        The synopses below generally provide the total spend for each line item the  
10       Company requests in this rate case. The details regarding breakout by historical  
11       period, projected bridge period, and projected test period, are each laid out in  
12       Exhibit A-12, Schedule B5.7.6 in columns (d), (g), and (h), respectively. Figure 6  
13       represents a high-level view of capital allocation within the Sub-Portfolio.

Line  
No.

1

Figure 6 IPS – IT Investment



2

3

*a) Regulatory/Compliance*

4

**Q56. What is the IPS Sub-Portfolio investment in the Regulatory/Compliance category?**

5

6

**A56.** The Company is seeking recovery for \$2.7 million in the Regulatory/Compliance category over the 36 months ending December 31, 2026, and the historical spend of \$0.6 million in 2023 as shown on lines 1 to 5 of Exhibit A-12, Schedule B5.7.6. These investments are described below.

7

8

9

10

(1) Cloud Privilege Access Management

11

Line  
No.

1 The Company is seeking recovery for \$0.03 million in the Cloud Privilege Access  
2 Management project over the 12 months ending December 31, 2024, and the  
3 historical spend of \$0.3 million in 2023, as shown on line 1 of Exhibit A-12,  
4 Schedule B5.7.6.

5

6 This project will complete the migration of the legacy on-premise CyberArk  
7 solution to a SaaS based model. The scope of work will include the identification  
8 of all privilege accounts across the Company in IT and OT environments.

9

10 The Company reflects a variance of \$0.45 million less in the 36 months ending  
11 December 31, 2025, than approved in Case No. U-21534. The scope of the project  
12 for 2024 and 2025 has been re-evaluated, resulting in a decision to replace the  
13 CyberArk application rather than renewing it. Consequently, the project scope has  
14 been revised, and the updated solution is now included in the Advanced Privilege  
15 Access Management project. See Exhibit A-24, Schedule N3 lines 148, 149 for  
16 additional project details.

17

18 (2) Communication Compliance and Data Loss Prevention (DLP)

19 The Company is seeking recovery for \$0.4 million in the Communication  
20 Compliance and Data Loss Prevention (DLP) project over the 24 months ending  
21 December 31, 2026, as shown on line 2 of Exhibit A-12, Schedule B5.7.6.

22

23 DTE's platform strategy to migrate security functions to its Microsoft platform will  
24 aid in monitoring and securing employee communications and ensuring that all

Line  
No.

1 compliance standards are met. With this project, tools such as Communication  
2 Compliance and Data Loss Prevention (DLP) will be configured and deployed to  
3 across all corporate channels of communication. See Exhibit A-24, Schedule N3  
4 Lines 150, 151 for additional project details.

5

6 (3) Non-Window and Mobile Endpoint Protection

7 The Company is seeking recovery for \$0.4 million in the Non-Window and Mobile  
8 Endpoint Protection project over the 24 months ending December 31, 2026, as  
9 shown on line 3 of Exhibit A-12, Schedule B5.7.6.

10

11 To maintain a strong security posture, DTE has implemented Microsoft Defender  
12 for endpoint protection. Currently active on Windows 10 endpoints and being  
13 deployed to Windows servers, the next step is to extend Defender to non-Windows  
14 servers/endpoints and mobile devices. Without proper protection, these assets are  
15 vulnerable to threats like malware, zero-day attacks, and insider threats. Deploying  
16 Defender will close this security gap. This project will configure and deploy  
17 Microsoft Defender across all corporate-owned assets yet to be onboarded. See  
18 Exhibit A-24, Schedule N3 Lines 152, 153 for additional project details.

19

20 (4) Patch and Certification Management Program

21 The Company is seeking recovery for \$1.7 million in the Patch and Certification  
22 Management Program project over the 24 months ending December 31, 2026, as  
23 shown on line 4 of Exhibit A-12, Schedule B5.7.6.

Line  
No.

1 This project will enhance tool connectivity and introduce significant automation to  
2 ensure the timely processing of thousands of certificate creations and renewals,  
3 preventing disruptions. Additionally, it will improve and automate patch  
4 management for application and infrastructure assets, operating systems, and  
5 database systems, including middleware. This automation will help reduce the risk  
6 of security breaches, insider threats, and external costs from ransomware or  
7 regulatory fines. This project will also help monitor patch releases and expiring  
8 network certificates on the Company's corporate IT network. See Exhibit A-24,  
9 Schedule N3 Lines 154, 155 for additional project details.

10

11 (5) Vulnerability Scan Tool

12 The Company is seeking recovery for 0.2 million in the Vulnerability Scan tool  
13 project over the 12 months ending December 31, 2024, and the historical spend of  
14 0.4 million in 2023, as shown on line 5 of Exhibit A-12, Schedule B5.7.5.

15

16 The scope of the project is to enhance risk identification using Qualys vulnerability  
17 scanning tools by deploying Qualys agents on all Windows and Linux assets,  
18 replacing hardware scanning servers with virtual ones, developing a network map  
19 scan methodology, and purchasing additional ServiceNow licenses for increased  
20 Configuration Management Database (CMDB) assets.

21 The Company reports a variance of \$0.3 million less in the 24 months ending  
22 December 31, 2024, than approved in Case No. U-21534 due to cost savings  
23 achieved by not integrating Qualys with Azure Cloud Connector. The integration  
24 would have degraded the Infoblox performance and therefore the Company's

Line  
No.

1 network. See Exhibit A-24, Schedule N3 Lines 156, 157 for additional project  
2 details.

3

4 *b) Return-to-Health*

5 **Q57. What is the IPS Sub-Portfolio investment in the Return-to-Health category?**

6 A57. The Company is seeking recovery for \$7.5 million in the Return-to-Health category  
7 over the 36 months ending December 31, 2026, and the historical spend of 0.4  
8 million in 2023, as shown in lines 6 to 9 of the Capital Expenditures – Exhibit A-  
9 12, Schedule B5.7.6. These investments are described below.

10

11 (1) Advanced Privileged Access Management

12 The Company is seeking recovery for \$4.4 million in the Advanced Privileged  
13 Access Management project over the 36 months ending December 31, 2026, as  
14 shown on line 6 of Exhibit A-12, Schedule B5.7.5.

15

16 Based on changes in the market for a Privileged Access Management (PAM)  
17 solution, and a new understanding about requirements for infrastructure and  
18 professional services, the Company has identified the need to use Delenia as an on-  
19 premise solution to protect privileged accounts in the cloud platforms currently in  
20 use at the Company. The Company's current PAM solution (CyberArk) has reached  
21 its end of life. Delenia provides the same features as CyberArk but also enables  
22 new capabilities for critical use cases. These include real-time monitoring and  
23 inventory of PAM accounts, AD Bridging, just-in-time / just-enough entitlement  
24 elevation, out of the box compliance reporting for NERC, SOX, PCI, behavioral

Line  
No.

1 analytics, geofencing, and change management integration with ServiceNow. See  
2 Exhibit A-24, Schedule N3 Lines 158 - 160 for additional project details.

3

4 (2) Cloud Security

5 The Company is seeking recovery for \$0.6 million in the Cloud Security project  
6 over the 24 months ending December 31, 2025, and the historical spend of \$0.08  
7 million in 2023, as shown on line 7 of Exhibit A-12, Schedule B5.7.6.

8

9 This project aims to enhance the Company's cloud security by implementing  
10 Microsoft Sentinel for Azure asset monitoring. Monitoring is a reactive capability  
11 and creates delays in the Company's response to security related events. Microsoft  
12 Sentinel provides proactive monitoring capabilities, for the cloud, that allow the  
13 Company to respond more quickly to security events thereby reducing risk and  
14 lowering impact to DTE systems.

15

16 The Company reports a variance of \$0.3 million less over the 36 months ending  
17 December 31, 2025, compared to the amount approved in Case No. U-21534, due  
18 to efficiency gains attributed to a revised project resource plan. See Exhibit A-24,  
19 Schedule N3 Lines 161 - 163 for additional project details.

20

21 (3) Cybersecurity Defense Center (CSDC) Growth and Lifecycle Management

22 The Company is seeking recovery for \$1.1 million in the Cybersecurity Defense  
23 Center (CSDC) Growth and Life Cycle Management project over the 36 months  
24 ending December 31, 2026, and the historical spend of \$0.3 million in 2023, as  
25 shown on line 8 of Exhibit A-12, Schedule B5.7.6.



Line  
No.

1 This project will enable cybersecurity monitoring capabilities and hardware life  
2 cycle to maintain detection of and defense against threats to DTE cyber assets. The  
3 project will utilize existing tools and processes to maintain the ability to monitor  
4 and respond to threats and incidents more effectively. The project will also cover  
5 network taps and sensors that ensure network monitoring remains operational.

6

7 The Company reports a variance of \$0.3 million more in the 36 months ending  
8 December 31, 2025, than was approved for cost recovery in Case No. U-21534. Of  
9 this amount, \$0.2 million is due to the 10% disallowance in 2023 and 20%  
10 disallowance in 2024 and 2025 as directed by the Case No. U-21534 Final Order.  
11 The remaining \$0.15 million is due to the additional Security Information and Event  
12 Management (SIEM) hardware and software purchase in 2024. See Exhibit A-24,  
13 Schedule N3 Lines 164 - 167 for additional project details.

14

15 (4) Security Information & Event Management (SIEM) End of Life  
16 Replacement

17 The Company is seeking recovery for \$1.0 million in the SIEM End of Life  
18 Replacement project over the 12 months ending December 31, 2025, as shown on  
19 line 9 of Exhibit A-12, Schedule B5.7.6.

20

21 SIEM performs real-time monitoring and analysis of security events, generates  
22 security alerts for investigation, and logs security data for compliance and auditing  
23 purposes including for NERC, Payment Card Industry (PCI), Security Exchange  
24 Commission (SEC), Sarbanes-Oxley (SOX), and TSA requirements. The current  
25 hardware that runs DTE's Security Information & Event Management System

Line  
No.

1 (SIEM), will be at end of life and unsupported by the vendor at the end of  
2 2025. Replacement hardware is mandatory to keep this critical monitoring system  
3 up-to-date and supported, which enables DTE to continue to comply with the  
4 aforementioned regulations. With this project the Company will purchase, install,  
5 and configure replacement hardware to support the cybersecurity infrastructure.

6

7 The Company reports a variance of \$0.2 million more than in the 12 months ending  
8 December 31, 2025, than was approved for cost recovery in Case No. U-21534 due  
9 to the 20% disallowance directed by the Case No. U-21534 Final Order. See Exhibit  
10 A-24, Schedule N3 Line 168 for additional project details.

11

12 *c) IT Enhancements*

13 **Q58. Please explain the IPS Sub-Portfolio investment in the IT Enhancements**  
14 **category.**

15 A58. The Company is seeking recovery for \$1.1 million in the IT Enhancements category  
16 over the 24 months ending December 31, 2026, and the historical spend of 0.2  
17 million in 2023, as shown in lines 10 and 11 of the Capital Expenditures – Exhibit  
18 A-12, Schedule B5.7.6. These investments are described below.

19

20 (1) Cyber Security for OT and ICS

21 The Company is seeking recovery for \$0.8 million in the Cyber Security for OT  
22 and ICS project over the 12 months ending December 31, 2026, as shown on line  
23 10 of Exhibit A-12, Schedule B5.7.6.

Line  
No.

1 Industrial environments are seeing an increasing use of ‘smart’ devices, frequently  
2 referred to as the Internet of Things (IOT) or the Industrial Internet of Things  
3 (IIOT). These digital, sensor-embedded, software managed devices can enable  
4 significant operational efficiencies. IT systems increasingly consume data from  
5 these operational technologies and utilities like DTE Electric are facing the  
6 challenge of securing this increasingly converged IT and OT environment. This  
7 project will provide security for the Company’s operational units and guard against  
8 outside actors by using the Forescout Platform to manage these risks, contain  
9 events, and mitigate threats. See Exhibit A-24, Schedule N3 Line 169 for additional  
10 project details

11

12 (2) Endpoint protection

13 The Company is seeking recovery for \$0.3 million in the Endpoint Protection  
14 project over the 12 months ending December 31, 2025, and the historical spend of  
15 \$0.2 million in 2023, as shown on line 11 of Exhibit A-12, Schedule B5.7.6.

16

17 This project will replace Symantec Endpoint Protection (SEP) with Microsoft  
18 Defender for Endpoint, enhancing cybersecurity capabilities and protecting against  
19 emerging threats.

Line  
No.

1 The Company reports a variance of \$0.3 million less over the 36 months ending  
2 December 31, 2025, as compared to the amount approved in Case No. U-21534. Of  
3 this amount, \$0.1 million more is due to the 10% disallowance in 2023 and 20%  
4 disallowance in 2024 and 2025 directed in the Case No. U-21534 Final Order.  
5 Additionally, (\$0.4) million of the variance is due to a reduction in the scope of the  
6 protection rollout plan. The ruggedized<sup>3</sup> devices were excluded from the protection  
7 software rollout due to the complexity of the endpoints and the software utilized.  
8 See Exhibit A-24, Schedule N3 Lines 170, 171 for additional project details.

9

10 *d) Strategic*

11 **Q59. What is the IPS Sub-Portfolio investment in the Strategic category?**

12 A59. The Company is seeking recovery for \$8.4 million in the Strategic category over  
13 the 36 months ending December 31, 2026, and the historical spend of 2.7 million  
14 in 2023, as shown in lines 12 to 19 of the Capital Expenditures – Exhibit A-12,  
15 Schedule B5.7.6. These investments are described below.

16

17 (1) Automated Provisioning

18 The Company is seeking recovery for \$3.9 million in the Automated Provisioning  
19 project over the 36 months ending December 31, 2026, and the historical spend of  
20 \$1.6 million in 2023, as shown on line 12 of Exhibit A-12, Schedule B5.7.6.

21

22 The project will replace DTE Electric's outdated Identity and Access Management  
23 (IAM) solution with SailPoint, completing its implementation and retiring the old  
24 Oracle Waveset tool. Key processes affected include HR onboarding, user access

---

<sup>3</sup> Devices designed to withstand extreme temperatures, dust, and vibrations, ideal for field

Line  
No.

1 reviews, compliance audits, and role-based access implementation. The project will  
2 streamline processes, secure system access, and automate account management.  
3 Each year from 2023 to 2026, DTE Electric will onboard additional Sarbanes-  
4 Oxley (SOX) applications to SailPoint, automate workflows, and integrate with  
5 Privilege Access Management and Single Sign-On solutions. This will improve  
6 security, user experience, and compliance with SOX requirements.

7

8 The Company reports a variance of \$1.0 million more for the 36 months ending  
9 December 31, 2025, than approved for cost recovery in Case No. U-21534. Of this  
10 amount, \$0.6 million is due to the 10% disallowance in 2023 and 20% disallowance  
11 in 2024 and 2025 as directed by the Case No. U-21534 Final Order. The remaining  
12 \$0.4 million is due to additional scope of addressing several key issues to enhance  
13 system security and functionality, including correcting user access permissions,  
14 ensuring accurate access rights assignment, resolving improper access removal  
15 requests to improve efficiency and reliability, and implementing a critical security  
16 update to protect the Company's system from potential threats, significantly  
17 enhancing its security posture. See Exhibit A-24, Schedule N3 Lines 172 - 175 for  
18 additional project details.

19

20 (2) Cyber Excellence Plan (CEP) Program

21 The Company is seeking recovery for \$1.0 million in the Cyber Excellence Plan  
22 (CEP) Program project over the 36 months ending December 31, 2026, and the  
23 historical spend of \$0.3 million in 2023, as shown on line 14 of Exhibit A-12,  
24 Schedule B5.7.6.

Line  
No.

1 The Company established the CEP Program to build a cross-business-unit  
2 collaborative team to identify and address cybersecurity issues that expose the  
3 Company's OT infrastructure at its facilities. DTE Electric hosted an Edison  
4 Electric Industry (EEI) Culture of Security (COS) Peer Review to receive and share  
5 best practice recommendations with industry peers regarding the Company's cyber  
6 and physical security landscape. Based on the recommendations received, the  
7 Company elected to focus the Cyber Excellence program on (1) the cybersecurity  
8 metrics collection process and presentation enhancements during 2023 and (2)  
9 continued expansion of the DTE Electric cybersecurity monitoring capability for  
10 OT during 2023-2024. In 2025, additional network sensors will be purchased and  
11 installed in specific critical electric generation OT network locations prioritized by  
12 electric generation capacity. Deploying these network sensors will aid in early  
13 detection of malicious cybersecurity events in these critical networks. In 2026, DTE  
14 Energy will continue to enhance the DTE cybersecurity monitoring capability for  
15 OT.

16  
17 The Company reports a variance of \$0.2 million more for the 36 months ending  
18 December 31, 2025, than approved for cost recovery in Case No. U-21534. Of this  
19 amount, \$0.1 million is due to the 10% disallowance in 2023 and 20% disallowance  
20 in 2024 as directed by the Case No. U-21534 Final Order. The remaining \$0.1  
21 million was for purchase of two (2) network sensors and labor charges to install  
22 these sensors. See Exhibit A-24, Schedule N3 Lines 179 - 182 for additional project  
23 details.

24

25 (3) Cyber Resilient Offline Data Recovery

Line  
No.

1 The Company is seeking recovery for \$1.0 million in the Cyber Resilient Offline  
2 Data Recovery project over the 24 months ending December 31, 2026, and the  
3 historical spend of \$0.4 million in 2023, as shown on line 15 of Exhibit A-12,  
4 Schedule B5.7.6.

5  
6 The Ransomware Recovery project has been renamed as the Cyber Resilient  
7 Offline Data Recovery to align with DTE's strategy of investing in cybersecurity.  
8 In 2026, the scope includes initiating recovery by restoring data from backups to a  
9 secure area and verifying that files are intact and accessible by applications. It also  
10 involves conducting thorough testing to ensure the restored data works correctly  
11 and is free from malware or ransomware, documenting the entire recovery process  
12 to note any issues and resolutions for future improvements, and planning regular  
13 recovery tests to ensure DTE's processes remain effective and adaptable to changes  
14 in the IT environment.

15  
16 The Company reports a variance of \$0.3 million less over the 36 months ending  
17 December 31, 2025, compared to the amount approved in Case No. U-21534. Of  
18 this amount, \$0.2 million is due to the 10% disallowance in 2023 and 20%  
19 disallowance in 2024 and 2025 directed by the Case No. U-21534 Final Order. The  
20 remaining \$0.1 million is due to deferral of scope. The project scope was re-  
21 evaluated and strategically shifted from a recovery to a detection and prevention  
22 approach. See Exhibit A-24, Schedule N3 Lines 183 - 185 for additional project  
23 details.

24

25 (4) Endpoint Privilege Management

Line  
No.

1 The Company is seeking recovery for \$0.4 million in the Endpoint Privilege  
2 Management project over the 24 months ending December 31, 2026, as shown on  
3 line 16 of Exhibit A-12, Schedule B5.7.6.

4  
5 Endpoint privilege management (EPM) is a critical security measure that helps  
6 ensure DTE Electric endpoints and networks are secure from cyber threats. This  
7 approach limits the number of people with administrative access to endpoints, such  
8 as laptops, desktops, and servers, by setting up policies and permissions that grant  
9 access only to authorized users. EPM enhances security by reducing the attack  
10 surface area, making it harder for external threats to gain unauthorized access. EPM  
11 can reduce the likelihood of malware and other types of cyberattacks since most  
12 attacks rely on exploiting administrative privileges to infiltrate a network. EPM is  
13 a robust security solution that enhances DTE's security posture and lowers the risk  
14 of successful threats, aligning with the Company's Microsoft platform strategy.  
15 This tool will reduce the need for users to have elevated local administrative  
16 privileges. See Exhibit A-24, Schedule N3 Lines 186, 187 for additional project  
17 details.

18

19 (4) IPS Jump Server End of Life Replacements and Application Active  
20 Directory Authentication

21 The Company is seeking recovery for \$0.5 million in the IPS Jump Server End of  
22 Life Replacements and Application Active Directory Authentication project over  
23 the 24 months ending December 31, 2026, as shown on line 18 of Exhibit A-12,  
24 Schedule B5.7.6.



Line  
No.

1 As a critical aspect of DTE's security-in-depth approach, jump servers need to be  
2 current. Jump Servers are secure devices that provide controlled access points to  
3 the network, ensuring only authorized users can access sensitive segments of the  
4 network. As technology evolves, new vulnerabilities are discovered and exploited  
5 by attackers, making older systems increasingly susceptible to attacks. Outdated  
6 jump servers can expose the Company to security breaches, data theft, and other  
7 forms of cyber-attacks. Two of the critical assets that will require upgrades include  
8 the IPS jump servers that have reached End of Life and 37 applications that need  
9 authentication / authorization to use the current Active Directory (AD) platform.  
10 The scope of this project is to replace and decommission end-of-life (EOL) jump  
11 server hardware to remediate aging infrastructure and provide support to enable AD  
12 based authentication/ authorization for the new set of applications. See Exhibit A-  
13 24, Schedule N3 Lines 191, 192 for additional project details.

14

15 *3. Infrastructure Operations*

16 **Q60. What are the projected costs for investments in the Infrastructure Operations**  
17 **Sub-Portfolio?**

18 A60. As reflected on Line 7 of Exhibit A-12 Schedule B5.7, page 1, capital expenditures  
19 for Infrastructure Operations total \$53.9 million for the historical test year ended  
20 December 31, 2023, \$90.9 million in the bridge period (for the 24 months ending  
21 December 31, 2025), and \$49.1 million for the projected test period ending  
22 December 31, 2026.

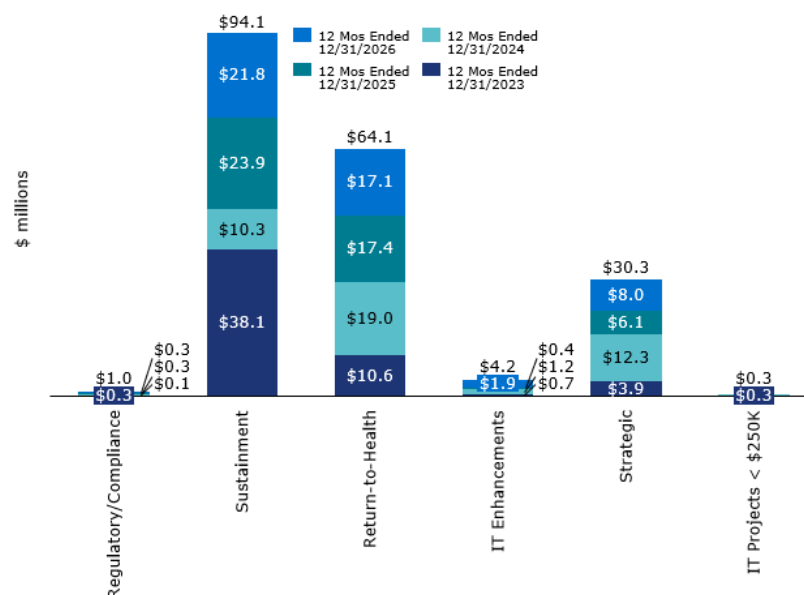
23

24 The synopses below generally provide the total spend for each line item the  
25 Company requests in this rate case and the details regarding breakout by historical

Line  
No.

period, projected bridge period, and projected test period, are each laid out in Exhibit A-12, Schedule B5.7.7, in columns d, g and h, respectively. Figure 7 below represents a high-level view of capital allocation within the Sub-Portfolio.

Figure 7 Infrastructure Operations – IT Investment

*Regulatory/Compliance*

**Q61. What is the Infrastructure Operations Sub-Portfolio investment in the Regulatory/Compliance category?**

**A61.** The Company is seeking recovery for \$0.7 million in the Regulatory/ Compliance category over the 36 months ending December 31, 2026, and the historical spend of \$0.3 million in 2023 as shown on lines 1 of the Capital Expenditures – Exhibit A-12, Schedule B5.7.7. These investments are described below.

- (1) Tower and Lighting Inspections and Repairs

Line  
No.

1 The Company is seeking recovery for \$0.7 million in the Tower and Lighting  
2 Inspections and Repairs project in the Regulatory/Compliance category of the  
3 Infrastructure Operations Sub-Portfolio over the 36 months ending December 31,  
4 2026, and the historical spend of \$0.3 million in 2023 as shown on lines 1 of the  
5 Capital Expenditures – Exhibit A-12, Schedule B5.7.7.

6 The Tower and Lighting Inspections and Repairs project is an annual effort that  
7 evaluates the integrity of the physical towers that carry the DTE network  
8 telecommunications lines and the real estate upon which the towers are built. These  
9 towers are used to provide reliable, efficient, and redundant network systems that  
10 are used by DTE IT and DTE Business Units in support of customers. Federal  
11 Communications Commission (FCC) regulations ensure the capability, security,  
12 and safety of these lines in the transmission of DTE data. See Exhibit A-24,  
13 Schedule N3 Lines 194 - 197 for additional project details.

14

15 *b) Sustainment*

16 **Q62. What is the Infrastructure Operations Sub-Portfolio investment in the**  
17 **Sustainment category?**

18 A62. The Company is seeking recovery for invest \$56 million in the Sustainment  
19 category of the Infrastructure Operations Sub-Portfolio over the 36 months ending  
20 December 31, 2026, and the historical spend of \$38.1 million over 12 months  
21 ending December 31, 2023, as shown in lines 2 to 12 of the Capital Expenditures –  
22 Exhibit A-12, Schedule B5.7.7. These investments are described below.

23

24 (1) Backup Environmental Growth

Line  
No.

1 The Company is seeking recovery for \$1.5 million in the Backup Environmental  
2 Growth project over the 36 months ending December 31, 2026, and the historical  
3 spend of \$0.09 million in 2023, as shown on line 2 of Exhibit A-12, Schedule  
4 B5.7.7.

5  
6 The Backup Environmental Growth project will continue in 2026. This project will  
7 ensure IT devices managing DTE data have sufficient capacity for backup creation  
8 and secure storage. See Exhibit A-24, Schedule N3 Lines 198 - 201 for additional  
9 project details.

10

11 (2) Collaboration Application Health

12 The Company is seeking recovery for \$19.7 million in the Collaboration  
13 Application Health project over the 36 months ending December 31, 2026, the  
14 historical spend of \$21.8 million in 2023, as shown on line 3 of Exhibit A-12,  
15 Schedule B5.7.7.

16

17 The Collaboration Application health project continues in 2026. The collaboration  
18 platform is a group of systems that enable employee productivity through  
19 collaborative communications, meetings, email, calendaring, instant messaging,  
20 co-authoring, and phone calls. This project is a continued year over year annual  
21 investment to sustain the collaboration platform, implement hardware and  
22 environment upgrades, security patches, and adopt both major and minor software  
23 releases to avoid or account for software version obsolescence. Improvements of  
24 this type are often critical in ensuring that system integrity is maintained allowing  
25 for the timely adoption of security patches and emerging versions.

Line  
No.

1 The Company reports a variance of \$5.1 million more in the 36 months ending  
2 December 31, 2025 than was approved in Case No. U-21534. Of this amount, \$2.8  
3 million is due to the 10% disallowance in 2023 and 20% disallowance in 2024 and  
4 2025 directed by the Case No. U-21534 Final Order. The remaining \$2.3 million  
5 represents the cost of the purchase of on-premise Microsoft Enterprise agreement  
6 licenses. See Exhibit A-24, Schedule N3 Lines 202 - 205 for additional project  
7 details.

8

9 (3) Dell Storage Hardware Refresh

10 The Company is seeking recovery for \$1.2 million in the Dell Storage and  
11 Hardware Refresh project over the 36 months ending December 31, 2026, as shown  
12 on line 4 of Exhibit A-12, Schedule B5.7.7.

13

14 The Dell Storage Hardware Refresh project continues in 2026. DTE must execute  
15 a new agreement to ensure the continuity of enterprise storage services. This  
16 contract is crucial as it affects the Company's storage capabilities, supporting all  
17 servers and enterprise-wide applications hosted on them. By renewing the Dell  
18 agreement, DTE can continue to meet its storage obligations critical enterprise  
19 applications that host both external and internal customer data. See Exhibit A-24,  
20 Schedule N3 Lines 206, 207 for additional project details.

21

22 (4) Endpoint End of Life Electric Support Services

23 The Company is seeking recovery for \$2.2 million in the Endpoint End of Life  
24 Electric Support Services project over the 36 months ending December 31, 2026,

Line  
No.

1 and the historical spend of \$1.3 million in 2023, as shown on line 5 of Exhibit A-  
2 12, Schedule B5.7.7.

3

4 The Endpoint End of Life Electric support Services project continues in 2026. This  
5 project is a year-over-year initiative to provide required endpoint operational  
6 support for end user issues impacting daily work requirements. The project will  
7 continue the Company's partnership with a third-party service provider to provide  
8 labor necessary to support endpoint asset health lifecycle. This spend reflects the  
9 capital labor portion of endpoint engineering services the Company uses for the  
10 deployment of the capital assets purchased under the Endpoint EOL project.

11 See Exhibit A-24, Schedule N3 Lines 208 - 211 for additional project details.

12

13 (5) Enterprise Monitoring Licensing

14 The Company is seeking recovery for \$5.0 million in the Enterprise Monitoring  
15 Licensing project over the 12 months ending December 31, 2025, as shown on line  
16 6 of Exhibit A-12, Schedule B5.7.5.

17

18 This project involves acquiring a three-year license for Dynatrace products,  
19 including Managed Host Unit Hours, Managed DEM Units, Managed Data  
20 Ingestion and Analytics, and Managed Log Analytics.

21

22 The Company reports a variance of \$1.0 million more in the 12 months ending  
23 December 31, 2025, than was approved for cost recovery in Case No. U-21534 due  
24 to the 20% disallowance directed in the Case No. U-21534 Final Order. See Exhibit  
25 A-24, Schedule N3 Line 212 for additional project details.

Line  
No.

1 (6) Enterprise Monitoring Strategy Operational Growth

2 The Company is seeking recovery for \$2.2 million in the Enterprise Monitoring  
3 Strategy Operational Growth project over the 36 months ending December 31,  
4 2026, and the historical spend of \$0.5 million in 2023, as shown on line 7 of Exhibit  
5 A-12, Schedule B5.7.7.

6

7 The Enterprise Monitoring Strategy Operational Growth project continues in 2026.  
8 Investment in Enterprise Monitoring Operational Growth expands the monitoring  
9 of critical applications, infrastructure, security, services, and user experiences. By  
10 2026, this project will extend application monitoring to 83% of all critical  
11 applications; the implementation of necessary upgrades will be an ongoing project.

12

13 The Company reports a variance of \$0.5 million more in the 36 months ending  
14 December 31, 2025, than was approved in Case No. U-21534. Of this amount, \$0.4  
15 million is due to disallowances of 10% in 2023 and 20% in 2024 and 2025 as  
16 directed by the Case No. U-21534 Final Order. The remaining \$0.1 million is  
17 attributed to additional costs incurred to replace StreamWeaver with PolyCloud  
18 automation due to the vendor discontinuing StreamWeaver. See Exhibit A-24,  
19 Schedule N3 Lines 213 - 216 for additional project details.

20

21 (7) Field Communications Network (FCN) Growth and Upgrade

22 The Company is seeking recovery for \$1.2 million in the Field Communications  
23 Network (FCN) Growth and Upgrade project over the 36 months ending December  
24 31, 2026, and the historical spend of \$0.4 million in 2023, as shown on line 8 of the  
25 Exhibit A-12, Schedule B5.7.7.

Line  
No.

1 Field Communications Network (FCN) Growth and Upgrade project continues in  
2 2026. The project is designed to provide redundant communication and control  
3 functionality for the Company's field devices (Routers, Switches and Hubs) that  
4 monitor and control the operation of the bulk-electrical-system network. This  
5 program replaces devices that are reaching the end of useful life, adds devices to  
6 accommodate load or geographical growth, and adds functionality, automation, and  
7 redundancy to the alternate System Operations Center location. Annually, this effort  
8 in both hardware and labor is required to ensure the communication hardware  
9 requiring replacement, upgrade, or reconfiguration meets the requirements of the  
10 business and the Company's customers.

11

12 The Company reports a variance of \$0.3 million more in the 36 months ending  
13 December 31, 2025, than was approved in Case No. U-21534. Of this amount, \$0.2  
14 million is due to the disallowances of 10% in 2023 and 20% in 2024 and 2025  
15 directed by the Case No. U-21534 Final Order. The remaining \$0.1 million is for  
16 replacement of failed routing devices and repairs of damaged fiber supporting FCN.  
17 See Exhibit A-24, Schedule N3 Line 217 - 220 for additional project details.

18

19 (8) Network Hardening and Operations

20 The Company is seeking recovery for \$1.7 million in the Network Hardening and  
21 Operations project over the 36 months ending December 31, 2026, and the  
22 historical spend of \$0.9 million in 2023, as shown on line 9 of Exhibit A-12,  
23 Schedule B5.7.7.



Line  
No.

1 The Network Hardening and Operations project continues in 2026. This project  
2 supports the Network Engineering services the Company uses for the deployment  
3 of capital assets purchased under the Network EOL program. This is a year-over-  
4 year project that assesses the Company's networks and implements operational  
5 system upgrades to fulfill the hardening requirements of network infrastructure  
6 required for a sustained quality of network services. Infrastructure and Operations  
7 partnered with a third-party service provider to provide the necessary labor support  
8 for this project. See Exhibit A-24, Schedule N3 Lines 221 - 224 for additional  
9 project details.

10

11 (9) Palo Alto Capital License Purchase

12 The Company is seeking recovery for \$5.5 million in the Palo Alto Capital License  
13 Purchase project over the 12 months ending December 31, 2025, as shown on line  
14 10 of Exhibit A-12, Schedule B5.7.7.

15

16 DTE leverages Palo Alto Networks based security infrastructure for securing the  
17 Company's network and providing the protection needed for critical assets such as  
18 AMI. Palo Alto licensing was renewed in 2022 to ensure functionality and  
19 supportability of network security assets needed for DTE's IT and OT/Control  
20 networks. This licensing and support will expire in 2025, necessitating renewal.

21

22 The Company reports a variance of \$1.1 million more in the 12 months ending  
23 December 31, 2025, than was approved for cost recovery in Case No. U-21534, due  
24 to the 20% disallowance directed in the Case No. U-21534 Final Order. See Exhibit  
25 A-24, Schedule N3 Line 225 for additional project details.

Line  
No.

1 (10) Server Engineering Support Services

2 The Company is seeking recovery for \$10.1 million in the Server Engineering  
3 Support Services project over the 36 months ending December 31, 2026, and the  
4 historical spend of \$13.2 million 2023, as shown on line 11 of Exhibit A-12,  
5 Schedule B5.7.7.

6

7 The Server Engineering Support Services project continues in 2026. This project  
8 provides work products and services with defined service level agreements for  
9 Server and Database Engineering & Operations teams. The planned spend reflects  
10 capital labor supporting the deployment of the capital assets purchased under Server  
11 and Database Engineering & Operations. Without the necessary support, the IDSS  
12 team is unable to adequately staff projects, perform upgrades, and execute  
13 infrastructure improvements.

14

15 The Company reports a variance of \$5.5 million more in the 36 months ending  
16 December 31, 2025, than was approved for cost recovery in Case No. U-21534. Of  
17 this amount, \$1.6 million is due to the disallowances of 10% in 2023 and 20% in  
18 2024 and 2025 directed by the Case No. U-21534 Final Order. The remaining \$3.9  
19 million will be utilized to buy out the lease on essential assets, such as SAN  
20 Directors and Data Domains, which is a more cost-effective approach than  
21 replacing them. See Exhibit A-24, Schedule N3 Lines 227 - 229 for additional  
22 project details.

Line  
No.

1 (11) VMWare License Purchase

2 The Company is seeking recovery for \$5.6 million in the VMWare License  
3 Purchase project over the 12 months ending December 31, 2025, as shown on line  
4 12 of Exhibit A-12, Schedule B5.7.7.

5

6 VMware is a virtualization and cloud computing software for IT infrastructure like  
7 VRealize operations, VRealize automation, VMWare Hypervisor and vCenter  
8 Server and vSphere Client, which the Company uses to run critical applications,  
9 such as AMI, Maximo, and SAP. The software licensing is reaching expiration in  
10 2025 and renewal of the licenses is required to ensure that DTE's critical  
11 infrastructure and applications remains operational.

12

13 The Company reflects a variance of \$1.1 million more in the 12 months ending  
14 December 31, 2025, than was approved for cost recovery in Case No. U-21534 due  
15 to the 20% disallowance directed by the Case No. U-21534 Final Order. See Exhibit  
16 A-24, Schedule N3 Line 230 for additional project details.

17

18 *c) Return-to-Health*

19 **Q63. What are the Infrastructure Operations Sub-Portfolio investment in the**  
20 **Return-to-Health category?**

21 A63. The Company is seeking recovery for \$53.5 million in the Return-to-Health  
22 category of the Infrastructure Operations Sub-Portfolio over the 36 months ending  
23 December 31, 2026, and the historical spend of \$10.6 million over 12 months  
24 ending December 31, 2023, as shown in lines 13 to 29 of the Capital Expenditures  
25 Exhibit A-12, Schedule B5.7.7. These investments are described below.

Line  
No.

1 (1) Compute and Storage Cache Refresh

2 The Company is seeking recovery for \$0.5 million in the Compute and Storage  
3 Cache Refresh project over the 24 months ending December 31, 2024, as shown on  
4 line 13 of Exhibit A-12, Schedule B5.7.7.

5  
6 The Compute and Storage Cache project is a one-year initiative aimed at enhancing  
7 the current storage capacity and supporting computing infrastructure that underpins  
8 essential business applications and functions throughout the enterprise.

9  
10 The Company reports a variance of \$0.1 million less in the 24 months ending  
11 December 31, 2024, than was approved for cost recovery in Case No. U-21534, due  
12 to the 20% disallowance directed by the Case No. U-21534 Final Order. See Exhibit  
13 A-24, Schedule N3 Lines 231, 232 for additional project details.

14

15 (2) Conference Room Audio Video Support

16 The Company is seeking recovery for \$1.0 million in the Conference Room Audio  
17 Video Support project over the 36 months ending December 31, 2026, and the  
18 historical spend of \$0.1 million in 2023, as shown on line 14 of Exhibit A-12,  
19 Schedule B5.7.7.

20

21 The Conference Room Audio Video Support project will continue in 2026. This  
22 project aims to offer technical expertise and the hardware necessary for maintaining  
23 equipment in DTE's conference rooms to ensure effective collaboration

Line  
No.

1 capabilities. See Exhibit A-24, Schedule N3 Lines 233 - 236 for additional project  
2 details.

3 (3) Data Center Modernization and Optimization

4 The Company is seeking recovery for \$3.5 million in the Data Center  
5 Modernization and Optimization project over the 36 months ending December 31,  
6 2026, and the historical spend of \$1.0 million in 2023, as shown on line 15 of  
7 Exhibit A-12, Schedule B5.7.7.

8  
9 The Data Center Modernization and Optimization project will continue in 2026.  
10 Data Center Modernization centers on corporate application servers, storage and  
11 core communications, and the distribution layer of services. Data Center  
12 Modernization focuses on the Company's central computing centers: the Detroit  
13 Data Center (DDC), Ann Arbor Data Center (ADC), Electrical Systems Operations  
14 Center (ESOC) and Alternate Systems Operations Center (ASOC). Four  
15 Uninterruptible Power Supplies (UPS) in core data centers have exceeded their 20-  
16 year service life; this project will replace them and the associated batteries to ensure  
17 power redundancy during outages. UPS units are crucial for providing emergency  
18 backup power until generators kick in, safeguarding critical IT equipment.  
19 Replacing the UPSs ensures reliable power during outages, maintaining business  
20 operations. The batteries are over five years old and will be upgraded to a newer  
21 technology that doubles their lifespan and reduces annual maintenance by 50%.  
22 Delaying the replacement of these end-of-life assets would increase the risk of loss  
23 of redundant power to the infrastructure assets that the Company uses to host its  
24 business applications and customer data.

Line  
No.

1 The Company reports a variance of \$0.6 million for the 36 months ending  
2 December 31, 2025, more than was approved for cost recovery in Case No. U-  
3 21534 due to the disallowance of 10% in 2023 and 20% in 2024 and 2025 directed  
4 by the Case No. U-21534 Final Order. See Exhibit A-24, Schedule N3 Lines 237 -  
5 240 for additional project details.

6

7 (4) Digital Worker Experience Electric EOL

8 The Company is seeking recovery for \$9.3 million in Digital Worker Experience  
9 Electric EOL (previously called Endpoint End of Life Electric) over the 36 months  
10 ending December 31, 2026, and the historical spend of \$2.8 million in 2023, as  
11 shown on line 16 of Exhibit A-12, Schedule B5.7.7.

12

13 The Digital Worker Experience EOL is an annual investment and will continue in  
14 2026. The scope of this project is to replace end-of-life endpoint devices like  
15 Laptops and Desktops to maintain the interfacing connectivity to DTE business  
16 systems, communications, and data. The primary interface devices used by the  
17 employees of DTE to access business systems, communications and data are on  
18 Laptops, desktops, tablets, and smart devices. These devices become degraded after  
19 5 years of service due to the age and versions of the internal components such as  
20 (mother boards, storage & wireless components). Refer to Table 3 below, Endpoint  
21 Device Replaced by Year.

Line  
No.**Table 3      Device Type and Count Breakdown**

| Device Type                                      | Refresh Year |      |      |      |
|--------------------------------------------------|--------------|------|------|------|
|                                                  | 2023         | 2024 | 2025 | 2026 |
| <b>Laptop</b>                                    | 742          | 867  | 676  | 380  |
| <b>Desktop</b>                                   | 1            | 82   | 114  | 38   |
| <b>Monitors</b>                                  | 180          | 2    | 63   | 21   |
| <b>Tablets</b>                                   | 25           | 17   | 17   | 15   |
| <b>Supplemental<br/>Field Worker<br/>Devices</b> |              | 175  |      |      |

The Company reports a variance of \$2.7 million for the 36 months ending December 31, 2025, this was more than what was approved for cost recovery in Case No. U-21534. Of this amount, \$0.6 million is due to the 10% disallowances in 2023 and 20% disallowance in 2024 and 2025 directed by the Case No. U-21534 Final Order. The remaining \$2.1 million is allocated for additional field worker devices for supplemental staff supporting storm restoration efforts and the DTE student program. See Exhibit A-24, Schedule N3 Lines 241 - 244 for additional project details.

(5)      End of Life Asset Replacements

The Company is seeking recovery for \$1.6 million in the End of Life (EOL) Asset Replacements project over the 36 months ending December 31, 2026, and the historical spend of \$0.2 million in 2023, as shown on line 17 of Exhibit A-12, Schedule B5.7.7.

Line  
No.

The EOL Asset Replacement project will continue in 2026. This project will replace servers, storage, databases, and operating licenses that are at end of their serviceable life, which means they are no longer capable of accepting operating system or security vulnerability remediation, capacity has reached the upper threshold of processing ability, or the technology will no longer interact with newer components within the architecture. These assets located within the Company's corporate data centers or major secondary sites rely on continuous upgrades to ensure that security, capacity, and operating parameters can meet business requirements (see Table 4 below).

**Table 4      Device Lifecycle Management Standards**

| Component         | Lifecycle       |
|-------------------|-----------------|
| Servers           | 5 Years         |
| Storage           | 3 Years         |
| Operating Systems | Annual Upgrades |
| Databases         | Annual Upgrades |

See Exhibit A-24, Schedule N3 Lines 245 - 248 for additional project details.

(6)      Endpoint Operating System and Hardware Upgrade

The Company is seeking recovery for \$14.1 million in the Endpoint Operating System and Hardware Upgrade project over the 36 months ending December 31, 2026, as shown on line 18 of Exhibit A-12, Schedule B5.7.7.



Line  
No.

1 As part of the Annual Planning and Prioritization Process detailed in Section IV,  
2 all investments underwent a thorough assessment. Following reviews, the Endpoint  
3 Operating System and Hardware Upgrade investment was reclassified as a Return  
4 to Health investment.

5  
6 The Endpoint Operating System and Hardware Upgrade project will continue in  
7 2026. DTE endpoint devices that have operating systems on antiquated technology  
8 will no longer be supported through Microsoft's standard support process. This  
9 will prevent the user from being able to perform their job responsibilities. This  
10 project completed necessary upgrades of 9,700 machines from Windows 10 to  
11 Windows 11, and replacement of 1,000 machines, in 2024, and will upgrade a total  
12 of 15,000 devices at project completion by 2026. Windows 10 extended support  
13 includes updating the operating system and this support officially ends October  
14 2025. Updating endpoint operating systems will reduce DTE's exposure to  
15 operating-system-based vulnerabilities within the Company's network. This three-  
16 year project further supports the strategic direction to upgrade to Windows 11 for  
17 the entire organization across roughly 10,000 devices.

18  
19 The Company reports a variance of \$1.6 million for the 36 months ending  
20 December 31, 2025, more than that approved in Case No. U-21534 Order. Of this  
21 amount, \$1.4 million is due to the disallowances of 10% for the level 3 estimate in  
22 2023 and 20% for the level 2 estimate in 2024 and 2025 directed by the Case No.  
23 U-21534 Final Order. The remaining \$0.2 million is due to increased third party  
24 storage facility and procurement of endpoint devices costs. See Exhibit A-24,  
25 Schedule N3 Lines 249 - 251 for additional project details.

Line  
No.

1 (7) Field Worker Device End of Life

2 The Company is seeking recovery for \$2.7 million in the Field Worker Device End  
3 of Life project over the 36 months ending December 31, 2026, as shown on line 19  
4 of Exhibit A-12, Schedule B5.7.7.

5

6 The Field Worker Device End of Life project will continue in 2026. This project  
7 will establish and execute the annual EOL replacement cycle for the enterprise  
8 Mobile Data Terminal (MDT) devices. MDT is a computerized device used on  
9 mobile devices (devices in transit or devices that are mounted on systems that are  
10 always on the move) to communicate with a centralized control system. Mobile  
11 data terminals are equipped with technology to provide maps and information  
12 systems regarding geographic locations and other information relevant to the tasks  
13 and actions performed by the devices they are mounted on. These capabilities allow  
14 field workers to resolve customer issues efficiently and provide input to customer  
15 service representatives so they may effectively respond to customer queries.

16

17 The lifecycle of the current MDT fleet has been stretched to the point that field  
18 crew are experiencing multiple device and connectivity failures. This impacts the  
19 crew's ability to gain insight into customer issues and outages, provide updates to  
20 leadership and customer service, and communicate resolution and closure of  
21 customer concerns in a safe and efficient way. See Exhibit A-24, Schedule N3 Lines  
22 252 - 254 for additional project details.

Line  
No.

1 (8) Load Balancer Asset Health and Re-Engineering

2 The Company is seeking recovery for \$0.9 million in the Load Balancer Asset  
3 Health and Re-Engineering project over the 24 months ending December 31, 2026,  
4 as shown on line 20 of Exhibit A-12, Schedule B5.7.7.

5

6 The Load Balancer Asset Health and Re-Engineering project will continue in 2026.

7 This project will replace the hardware load balancers that will be deemed end of  
8 life by 2025 with modern virtual load balancers. Virtual load balancers are  
9 software-based load balancing solutions that help distribute network traffic load  
10 among backend servers. Having unsupported load balancers would increase  
11 security vulnerabilities to approximately 4000 URLs required for applications to  
12 function to support operations. See Exhibit A-24, Schedule N3 Lines 255, 256 for  
13 additional project details.

14

15 (9) Microwave End of Life

16 The Company is seeking recovery for \$1.3 million in the Microwave End of Life  
17 project over the 36 months ending December 31, 2026, and the historical spend of  
18 \$0.4 million in 2023, as shown on line 21 of Exhibit A-12, B5.7.7.

19 The Microwave End of Life project will continue in 2026. The Company owns and  
20 operates its own set of microwave communications installations. The continued  
21 implementation of this project supports the hardware and configuration and  
22 sustainment of higher network speeds, efficient transmission of data, voice, and  
23 video for DTE facilities. This investment will replace microwave paths, implement  
24 enhancements to stabilize the microwave ring, and support changes mandated by  
25 the FCC in deregulation of the 6 gigahertz (Ghz) frequency. These efforts provide

Line  
No.

1 overall improvements to infrastructure redundancy, availability, and security. See  
2 Exhibit A-24, Schedule N3 Lines 257 - 260 for additional project details.

3

4 (10) Modernize Disaster Recovery Tools

5 The Company is seeking recovery for \$0.5 million in the Modernize Disaster  
6 Recovery Tools project over the 12 months ending December 31, 2025, as shown  
7 on line 22 of Exhibit A-12, Schedule B5.7.7.

8

9 This project will modernize the aged Disaster Tolerance High Availability (DTHA)  
10 Commander web application and components. The project scope includes replacing  
11 these components with current, supportable technology by re-engineering and  
12 migrating them to DTE's private cloud (Azure Stack) platform.

13

14 The Company reports a variance of \$0.1 million for the 12 months ending  
15 December 31, 2025, more than approved for cost recovery in Case No. U-21534,  
16 due to the 20% disallowance in 2025 as directed by the Case No. U-21534 Final  
17 Order. See Exhibit A-24, Schedule N3 Line 261 for additional project details.

18

19 (11) Network Advanced Metering Infrastructure Support

20 The Company is seeking recovery for \$4.5 million in the Network Advanced  
21 Metering Infrastructure Support project over the 24 months ending December 31,  
22 2025, and the historical spend of \$2.1 million in 2023 as shown on line 23 of Exhibit  
23 A-12, Schedule B5.7.7.

Line  
No.

1 The Network Advanced Metering Infrastructure Support project will continue in  
2 2026. This project will maximize the usage of the assets such as Fiber cable, Dense  
3 Wavelength Division Multiplexing, routers, and TROPOS components of AMI  
4 with more precision, which assists in improving the read rate and throughput.  
5 Additionally, this effort improves operational return to health for the TROPOS  
6 mesh.

7

8 The Company reports a variance of \$1.2 million more in the 36 months ending  
9 December 31, 2025, than was approved in Case No. U-21534. Of this amount, \$1.1  
10 million is due to the disallowances of 10% in 2023 and 20% in 2024 and 2025  
11 directed by the Case No. U-21534 Final Order. The remaining \$0.1 million  
12 represents labor costs related to the Customer Power Status project, which aims to  
13 improve mesh availability and support Power Off Notification data to help crews  
14 locate outages closer to the source. See Exhibit A-24, Schedule N3 Lines 262 - 264  
15 for additional project details.

16

17 (12) Network Data Center End of Life

18 The Company is seeking recovery for \$1.6 million in the Network Data Center End  
19 of Life Project over the 36 months ending December 31, 2026, and the historical  
20 spend of \$0.7 million in 2023, as shown on line 24 of Exhibit A-12, Schedule  
21 B5.7.7.

22

23 The Network Data Center End of Life Project will continue in 2026. This project  
24 will replace data-center core switches, routers, and install new components to allow  
25 the Company to increase the connection bandwidth between its two data centers.

Line  
No.

1 Business applications with a requirement of failover and backup capabilities rely  
2 on the operability of these devices to ensure continuity in the event of an unplanned  
3 outage. See Exhibit A-24, Schedule N3 Lines 265 - 268 for additional project  
4 details.

5

6 (13) Network End of Life Electric

7 The Company is seeking recovery for \$2.1 million in the Network End of Life  
8 Electric project over the 36 months ending December 31, 2026, and the historical  
9 spend of \$0.8 million in 2023, as shown on line 25 of Exhibit A-12, Schedule  
10 B5.7.7.

11

12 The Network End of Life Electric project will continue in 2026. This project is an  
13 ongoing investment to replace EOL network hardware that is not physically located  
14 in either of the corporate data centers. These updated solutions will address the  
15 components that have reached their end of designed and serviceable life, and  
16 provide additional network expansions to meet business-partner requirements,  
17 expectations, and demand (see Table 5 below).

18

19

**Table 5 Network Devices Replaced by Year**

| <b>Year</b>            | <b>2026</b>   | <b>2023</b> | <b>2024</b> | <b>2025</b> |
|------------------------|---------------|-------------|-------------|-------------|
| <b>Assets Replaced</b> | Not yet known | 50          | 100         | 100         |

20

21 See Exhibit A-24, Schedule N3 Line 269-272 for additional project details.

Line  
No.

1 (14) Network UPS End of Life

2 The Company is seeking recovery for \$0.5 million in the Network UPS End of Life  
3 project over the 12 months ending December 31, 2026, as shown on line 26 of  
4 Exhibit A-12, Schedule B5.7.7.

5

6 DTE's network Uninterruptible Power Supply (UPS) units are aging, and their  
7 batteries require frequent replacements, leading to budget planning challenges. The  
8 unpredictability of UPS failures causes telecom closets to fail, disrupting the  
9 operation of telecom equipment. These closets are end user devices at the access  
10 layer to provide services for workstations and laptops. This project will collaborate  
11 with a third party vendor and utilize UPS to provide reliable network connectivity  
12 for DTE's end users. This includes monitoring, repairs, maintenance and  
13 deployment of UPSs over a period of three years. The replacement cycle is based  
14 on the end-of-life criteria of the Company's UPSs. See Exhibit A-24, Schedule N3  
15 Line 273 for additional project details.

16

17 (15) Security Infrastructure Growth and EOL

18 The Company is seeking recovery for \$4.4 million in the Security Infrastructure  
19 Growth and EOL project over the 36 months ending December 31, 2026, and the  
20 historical spend of \$1.4 million in 2023, as shown on line 27 of Exhibit A-12,  
21 Schedule B5.7.7.

22

23 The Security Infrastructure Growth and EOL project will continue in 2026. This  
24 ongoing project replaces 15% to 20% of security infrastructure equipment annually.  
25 These systems average a life span of five to seven years based on OEM

Line  
No.

1 recommendations. As reflected in Table 6 below, these systems have the following  
2 equipment replacement cycle to ensure they remain within vendor supportable life:

3  
4 **Table 6 Security Asset Lifecycle**

| Asset                            | Lifecycle |
|----------------------------------|-----------|
| System Baselineing               | 4 years   |
| Firewalls                        | 5 years   |
| Domain Name System (DNS)         | 6/7 years |
| Vulnerability Tool               | 6 years   |
| Web Proxy                        | 5 years   |
| DataPower                        | 4 years   |
| Windows server hardware/software | 5-7 years |

5  
6 The annual upgrades increase these systems' capacity to manage growth in the IT  
7 and OT environments. The Company reflects a variance of \$0.9 million more in the  
8 36 months ending December 31, 2025, than was approved for cost recovery in Case  
9 No. U-21534. Of this amount, \$0.7 million is due to the disallowances of 10% in  
10 2023 and 20% in 2024 and 2025 directed by the Case No. U-21534 Final Order.  
11 The remaining \$0.2 million is additional scope for purchase of Digital Network  
12 Architecture (DNA) licenses. DNA allows for an optimized management of  
13 network device licenses. See Exhibit A-24, Schedule N3 Lines 274 - 277 for  
14 additional project details.

15  
16 (16) Virtual Desktop Infrastructure Asset Health

17 The Company is seeking recovery for \$2.4 million in the Virtual Desktop  
18 Infrastructure Asset Health project over the 36 months ending December 31, 2026,  
19 as shown in line 28 of Exhibit A-12, Schedule B5.7.7.



Line  
No.

1 The Virtual Desktop Infrastructure Asset Health project will continue in 2026. The  
2 Company's current virtual desktop hardware, including virtual desktops and  
3 application clusters, will reach the end of its life by the end of 2025. This hardware  
4 provides secure virtual network connectivity to approximately 7,000 users across  
5 the enterprise. Without necessary replacements, all users relying on this  
6 infrastructure would lose connectivity, impacting their daily operations.

7

8 Currently, the virtual desktop and application infrastructure is based on Citrix. The  
9 Company is in the process of migrating to a hybrid Azure-based solution, using  
10 both private and public clouds to deliver Azure Virtual Desktops (AVD). To  
11 maximize the value of existing assets, as Citrix components reach end-of-life, they  
12 are being replaced with Azure-based solutions. This project, which began in 2024,  
13 is expected to be completed by 2026. By then, over 50% of the Company's Citrix  
14 infrastructure will have been migrated to Azure. This project marks the final phase  
15 of removing Citrix from the DTE environment. The new solution will continue to  
16 provide secure virtual desktop and application connectivity to approximately 7,000  
17 users. Without this project's continuation, the Company would need to maintain  
18 two technologies to provide the same solution, increasing complexity and costs.  
19 Additionally, this effort will address the PCI and NERC implementations of Citrix.

20

21 The Company reports a variance of \$0.3 million more in the 24 months ending in  
22 December 31, 2025, than was approved for cost recovery in Case No. U-21534, due  
23 to the 20% disallowance directed by the Case No. U-21534 Final Order. See Exhibit  
24 A-24, Schedule N3 Lines 278 - 280 for additional project details.

Line  
No.

1 (17) Wide Area Network and Wireless Local Area Network Expansion

2 The Company is seeking recovery for \$2.6 million in the Wide Area Network and  
3 Wireless Local Area Network Expansion project over the 36 months ending  
4 December 31, 2026, and the historical spend of \$1.2 million in 2023, as shown on  
5 line 29 of Exhibit A-12, Schedule B5.7.7.

6

7 The Wide Area Network and Wireless Local Area Network Expansion project will  
8 continue in 2026. Wide Area Network (WAN) is the core network equipment  
9 responsible for the telephony service at most of the Company's office locations.  
10 This project provides the necessary backbone hardware to meet the  
11 telecommunications demand of the enterprise and prepare for the increasing  
12 demands of a remote workforce. This project will replace the telephony platform  
13 with a more efficient one, align with the MicroSoft Teams application, and allow  
14 for deployment of e911. Additionally, the current state of the Wireless Local Area  
15 Network (WLAN) requires expansion to cover new locations and additional points  
16 of activity to ensure connectivity for field and knowledge workers at DTE locations.  
17 This project aims to provide appropriate WLAN communication needs for daily  
18 business operations, ensuring security and sustainability. This will support  
19 providing Network connectivity at the point of activity.

20

21 The Company reports a variance of \$0.6 million more in the 36 months ending  
22 December 31, 2025, than was approved for cost recovery in Case No. U-21534. Of  
23 this amount, \$0.4 million is due to disallowances of 10% in 2023 and 20% in 2024  
24 and 2025 directed by the Case No. U-21534 Final Order. The remaining \$0.2  
25 million is due to the deferral of equipment receipt planned for 2022, which could

Line  
No.

1 not be received until 2023 due to vendor supply chain issues. See Exhibit A-24,  
2 Schedule N3 Lines 281 - 284 for additional project details.

3

4 *d) IT Enhancements*

5 **Q64. What is the Infrastructure Operations Sub-Portfolio investment in the IT**  
6 **Enhancements category?**

7 A64. The Company is seeking recovery for \$3.6 million in the IT Enhancement category  
8 of the Infrastructure Operations Sub-Portfolio over the 36 months ending December  
9 31, 2026, and the historical spend of \$0.7 million over 12 months ending December  
10 31, 2023, as shown in lines 30 to 33 of the Capital Expenditures – Exhibit A-12,  
11 Schedule B5.7.7. These investments are described below.

12

13 (1) Cloud Network Connectivity

14 The Company is seeking recovery for \$0.6 million in the Cloud Network  
15 Connectivity project over the 12 months ending December 31, 2026, as shown on  
16 line 30 of Exhibit A-12, Schedule B5.7.7.

17

18 DTE's cloud strategy to migrate key applications previously on-premises to the  
19 cloud requires robust and secure network connectivity between on-premises data  
20 centers and the cloud. Specifically, to sustain current operations with the required  
21 service levels, DTE's network configuration between off-premises cloud providers  
22 and its data centers needs increased load capacity and robust fail-over (backup)  
23 capability. The increased digitalization of operational monitoring technology assets  
24 also requires additional network infrastructure to support the growing network load.

Line  
No.

1 This project will migrate the existing Virtual Private Network (VPN) between  
2 DTE's data centers and the Azure cloud to the Azure ExpressRoute gateway. The  
3 Azure ExpressRoute gateway peering points facilitate private connections between  
4 client networks and Microsoft Azure cloud data centers with resilient routes. This  
5 capability provides a low-latency Microsoft backbone network that forms a highly  
6 resilient connection. Additionally, the solution can easily be ported to any cloud  
7 provider, such as Microsoft Azure or Amazon AWS. All applications currently  
8 leveraging the VPN connectivity between on-premises and the cloud will be  
9 migrated to the Azure ExpressRoute gateway as part of this effort. See Exhibit A-  
10 24, Schedule N3 Line 285 for additional project details.

11

12 (2) Field Network Director

13 The Company is seeking recovery for \$0.9 million in the Field Network Director  
14 project over the 12 months ending December 31, 2024, as shown on line 31 of  
15 Exhibit A-12, Schedule B5.7.7.

16

17 The Company owns approximately five hundred (500) cellular routers that reside  
18 on poles and other public spaces to provide DTE field communication capabilities.  
19 If any of these devices were removed from those locations, they could be used to  
20 penetrate the Company's field network. The Cisco Field Network Director (FND)  
21 enables a geofence to ensure devices remain at the installed location. With the FND  
22 system, if a device is removed outside of the geofence, it will cease to operate on  
23 the DTE network, thus securing the Company's infrastructure. The capability to  
24 detect device movement and limit functionality helps secure Company's field  
25 network. In addition to securing devices, real-time monitoring is improved through

Line  
No.

1 the FND dashboards over the existing method providing over-the-air lifecycle  
2 management. See Exhibit A-24, Schedule N3 Line 286 for additional project details

3

4 (3) Modernize Infrastructure automation to align with modern cloud focused  
5 tools

6 The Company is seeking recovery for \$0.9 million in the Modernize Infrastructure  
7 automation project to align with modern cloud focused tools project over the 12  
8 months ending December 31, 2026, as shown on line 32 of Exhibit A-12, Schedule  
9 B5.7.7.

10

11 The scope of this project is to re-tool DTE's on-premises infrastructure to align  
12 with cloud-focused tools, creating a unified automation platform for both on-  
13 premises and cloud environments. The project will procure and deploy Terraform  
14 (for building), Ansible (for configuration management), and Azure Update  
15 Manager. These tools will enable unified automation of infrastructure tasks,  
16 including building, patching, and configuration, across both on-premises and cloud  
17 systems. An alternative to this project would be to continue to manually perform  
18 the patching, upgrades, and provisioning, which are often slow, inefficient, and  
19 prone to errors. See Exhibit A-24, Schedule N3 Line 287 for additional project  
20 details.

21

22 (4) Network Segmentation (phase 2+) emergent extension

23 The Company is seeking recovery for \$1.2 million in the Network Segmentation  
24 (phase 2+) emergent extension project over the 36 months ending December 31,

Line  
No.

1 2026, and the historical spend of \$0.7 million in 2023, as shown on line 33 of  
2 Exhibit A-12, Schedule B5.7.7.

3

4 The Network Segmentation (phase 2+) emergent extension project will continue in  
5 2026. Cyber threats continue to rise, and it has become increasingly important to  
6 add additional cybersecurity countermeasures to the Company's networks. Legacy  
7 network switches must be replaced due to incompatibility with the new N9K-FX3  
8 network switches. This incompatibility prevents the configuration of the Cisco  
9 Application Centric Infrastructure (ACI) technology that restricts traversing the  
10 DTE network. This has impacted the installation and use of firewalls to isolate  
11 applications running on obsolete operating systems. This project will support  
12 installation and configuration of a combination of Cisco N9X3 network switch  
13 based ACI technology and firewalls to isolate applications from intrusion.  
14 Separation of critical applications and data from general infrastructure is necessary  
15 to mitigate the risk of cybersecurity incidents.

16

17 The Company reports a variance of \$0.3 million more in the 36 months ending  
18 December 31, 2025, than was approved for cost recovery in Case No. U-21534. Of  
19 this amount, \$0.1 million is due to the disallowances of 10% in 2023 and 20% in  
20 2024 and 2025 as directed by the Case No. U-21534 Final Order. The remaining  
21 \$0.2 million is due to the Company merging the scope of the network access control  
22 project into this project as the required level of network access control can be  
23 achieved by further segmentation of the network. See Exhibit A-24, Schedule N3  
24 Lines 288 - 291 for additional project details.

Line  
No.

1                    *e) Strategic*

2    **Q65. What is the Infrastructure Operations Sub-Portfolio investment in the**  
3                    **Strategic category?**

4    A65. The Company is seeking recovery for \$26.3 million in the Strategic category of the  
5                    Infrastructure Operations Sub-Portfolio over the 36 months ending December 31,  
6                    2026, and the historical spend of \$3.9 million over 12 months ending December 31,  
7                    2023, as shown in lines 34 through 44 of the Capital Expenditures Exhibit A-12,  
8                    Schedule B5.7.7. These investments are described below.

9

10                    (1) Cellular Gateway Upgrade

11                    The Company is seeking recovery for \$0.6 million in the Cellular Gateway Upgrade  
12                    project over the 12 months ending December 31, 2026, as shown on line 34 of  
13                    Exhibit A-12, Schedule B5.7.7.

14

15                    DTE Electric systems increasingly rely on remote device connectivity to operate  
16                    and control our grid edge devices, requiring a robust field communication network.  
17                    The anticipated exponential growth in the number of grid edge devices demand a  
18                    reliable, secure and highly performing Field Communication Network, to provide  
19                    near real-time grid management capabilities with optimal performance. There is a  
20                    need to introduce network devices that are secure, reliable, and centrally managed  
21                    via automation and meet the performance needs of the future. In alignment with  
22                    this initiative, this project will replace outdated cellular gateways with newer  
23                    cellular gateways. This upgrade is intended to bolster field network communication  
24                    network security, reliability and manageability. See Exhibit A-24, Schedule N3  
25                    Line 292 for additional project details.

Line  
No.

1 (2) Cloud Program Automation

2 The Company is seeking recovery for \$3.9 million in the Cloud Program  
3 Automation project over the 12 months ending December 31, 2026, as shown on  
4 line 35 of Exhibit A-12, Schedule B5.7.7.

5  
6 DTE has setup a cloud foundation using infrastructure as code (IaC) automation  
7 that provides resilience to storm applications and customer facing applications. As  
8 cloud adoption increases at the Company, so does the requirement to enhance the  
9 foundation and to have a robust level of observability into cloud assets. The Cloud  
10 Program Automation project is focused on building out cloud capabilities using  
11 automation with a product mindset and implement tooling to visualize cloud spend,  
12 optimize operations, improve security posture, and enable real-time monitoring.  
13 This initiative will allow DTE to leverage the full benefits of adopting cloud and  
14 help the Company rapidly transform IT into a more agile and modern organization  
15 using best-in class principles for cloud. The project will also implement tools to  
16 monitor operational metrics, system performance, cloud spending, and security  
17 risks. See Exhibit A-24, Schedule N3 Line 293 for additional project details.

18  
19 (3) ConnectUs Teams

20 The Company is seeking recovery for a historical spend of \$1.0 million in the  
21 ConnectUs Teams project over the 12 months ending December 31, 2023, as shown  
22 on line 36 of exhibit A-12, Schedule B5.7.7.

23  
24 This is a continuation of the project in 2023. The Company has adopted an  
25 increasingly electronic collaboration method through Microsoft Teams and its



Line  
No.

connected services and products, formerly referred to as Skype for Business Conversion (to Teams). Ongoing investment in this conversion represents the continuation of a multi-year implementation of infrastructure and software updates to enhance the Company's security, simplify support efforts, drive collaboration, and enable its workforce to effectively work remotely. The Company has been able to reduce teleconferencing expenses by 80% (comparing 2020 actuals to 2022 actuals) to date with the rollout of Teams calling capability, as shown in Table 7 below.

**Table 7      Teleconferencing Actuals by Year**

| Spend category          | 2020              | 2021             | 2022             | 2023            |
|-------------------------|-------------------|------------------|------------------|-----------------|
| COM NETWORK SERVICES    | 159,194.15        | 52,355.77        | 36,229.55        | 8,988.79        |
| TELECONFERENCING        | 173,595.46        | 37,957.32        | 30,416.21        | 0               |
| <b>Grand Total (\$)</b> | <b>332,789.61</b> | <b>90,313.09</b> | <b>66,645.76</b> | <b>8,988.79</b> |

The Company reports a variance of \$0.2 million more in the 12 months ending December 31, 2023, than was approved for cost recovery in Case No. U-21534. Of this amount, \$0.1 million was due to the 10% disallowance directed by the Case No. U-21534 Final Order and the remaining \$0.1 million is for installation of the Microsoft Collaboration Platform at Fermi. This was in addition to the six sites that were planned for 2023. See Exhibit A-24, Schedule N3 Line 294 for additional project details.

**(4)      Data Power Replacement Phase 2**

The Company is seeking recovery for \$0.7 million in the Data Power Replacement Phase 2 project over the 12 months ending December 31, 2024, as shown on line 38 of Exhibit A-12, Schedule B5.7.7.

Line  
No.

1 DTE uses DMZ DataPower Gateway to provide security services for applications  
2 that are not externally exposed. The services include authentication/authorization  
3 for the users to access applications based on need, as well as provide layered  
4 protection to prevent unauthorized access. It is also used as an identity provider for  
5 some of the Company's cloud hosted applications. Today this capability resides on  
6 physical servers in DTE's data centers. This project will move current functionality  
7 to cloud. The adoption of this technology will provide the Company with the ability  
8 to securely enable business critical applications and better enable future cloud  
9 offerings. The solution would protect the confidentiality, integrity and availability  
10 of applications.

11

12 The Company reflects a variance of \$0.1 million more in the 12 months ending  
13 December 31, 2024, than was approved for cost recovery in Case No. U-21534, due  
14 to the 20% disallowance directed by the Case No. U-21534 Final Order. See Exhibit  
15 A-24, Schedule N3 Line 296 for additional project details.

16

17 (5) DTE Private Cloud Infrastructure as a Service

18 The Company is seeking recovery for \$0.03 million in the DTE Private Cloud  
19 Infrastructure as a Service project over the 12 months ending December 31, 2024,  
20 and the historical spend of \$0.8 million ending December 31, 2023, as shown on  
21 line 39 of Exhibit A-12, Schedule B5.7.7.

22

23 The DTE Private Cloud Infrastructure as a Service (IaaS) is a cloud computing  
24 model where a single organization, like DTE, can enjoy the benefits of scalability  
25 and flexibility along with the security and control of on-premises infrastructure.

Line  
No.

1 DTE can replace aging hardware and wired infrastructure by moving applications  
2 and related systems (like databases) to the DTE Private Cloud instance.

3 This model offers several improvements over off-premises cloud instances:

- 4 • **Enhanced Security:** The entire cloud instance is dedicated to one organization.
- 5 • **Improved Control:** DTE can manage and monitor resources, apply patches,  
6 and enforce security policies.
- 7 • **Scalability:** Resources can be dynamically scaled up or down as needed,  
8 improving system performance and reliability.
- 9 • **Compliance:** Private clouds can be designed to meet specific regulatory and  
10 compliance standards.

11

12 The Company reports a variance of \$0.3 million more in the 12 months ending  
13 December 31, 2023, than was approved for cost recovery in Case No. U-21534 for  
14 purchase of additional Microsoft On-Premises cloud license capacity and testing by  
15 vendor to validate the system capabilities, through-put, and ability to host database  
16 and related applications. See Exhibit A-24, Schedule N3 Lines 297, 298 for  
17 additional project details

18

19 (6) IT Service Management Tool - Hardware Asset Management

20 The Company is seeking recovery for \$0.5 million in the IT Service Management  
21 Tool – Hardware Asset Management project over the 12 months ending December  
22 31, 2026, as shown on line 43 of Exhibit A-12, Schedule B5.7.7.

23

24 The IT Service Management Tool – Hardware Asset Management project will  
25 continue in 2026. The scope of the project is to configure, build, test and deploy the

Line  
No.

1       ServiceNow hardware Asset management module to meet DTE's requirements  
2       within the ServiceNow platform the Company already owns. This implementation  
3       will require development, testing, pre-production and production release phases.  
4       ServiceNow Hardware Asset lifecycle automation will increase the accuracy of  
5       DTE's Asset lifecycle automation, improving efficiency in maintaining hardware  
6       asset information and in executing asset health projects. See Exhibit A-24,  
7       Schedule N3 Line 304 for additional project details.

8

9       (7)     Storm Cloud

10       The Company is seeking recovery for \$19.7 million in Storm Cloud project over  
11       the 36 months ending December 31, 2026, as shown on line 44 of Exhibit A-12,  
12       Schedule B5.7.7.

13

14       DTE has encountered several technology challenges during storms, increasing  
15       restoration costs and affecting customer satisfaction. System resiliency for the  
16       Company's cloud-based applications has become a critical issue. In 2022 and 2023,  
17       DTE faced six catastrophic storms impacting 2.1 million customers. During these  
18       events, performance degradation in critical applications disrupted service,  
19       preventing customers from reporting outages via mobile apps and forcing field  
20       workers to use manual alternatives. These issues stem from overloaded IT systems  
21       and failing integrations, primarily within the Azure Cloud. The project will enhance  
22       IT performance, ensuring automated scalability and improving support during  
23       storm efforts. This will boost operational reliability and customer satisfaction.

Line  
No.

1 This project supports the Company's storm response investments discussed in  
2 Company Witness Hill's testimony and the customer interaction improvements as  
3 discussed in Section VI.D.4.c of my testimony.

4 The Company reports a variance of \$3.9 million more in the 24 months ending  
5 December 31, 2025, than was approved for cost recovery in Case No. U-21534. Of  
6 this amount, \$3.2 million is due to the 20% disallowance in 2024 and 2025 directed  
7 by the Case No. U-21534 Final Order. The remaining \$0.7 million is for additional  
8 BlueCat and Infoblox software purchases required to reduce on-prem infrastructure  
9 dependency. See Exhibit A-24, Schedule N3 Lines 305 - 307 for additional project  
10 details.

11

12 *4. Enterprise Data Analytics*

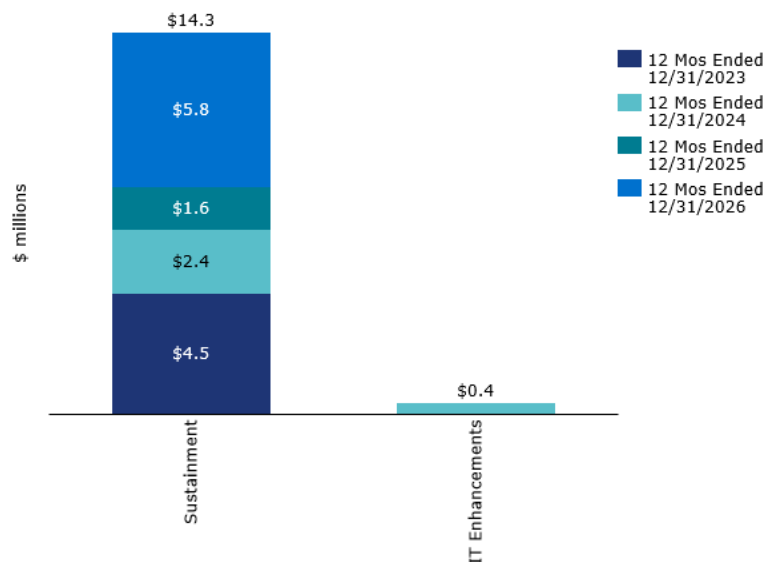
13 **Q66. What are the projected costs for investments in the Enterprise Data Analytics**  
14 **Sub-Portfolio?**

15 A66. As reflected on line 8 of Exhibit A-12, Schedule B5.7, page 1, capital expenditures  
16 for Enterprise Data Analytics total \$4.6 million for the historical test year ended  
17 December 31, 2023, \$4.4 million in the bridge period (for the 24 months ending  
18 December 31, 2025), and \$5.8 million for the projected test period ending  
19 December 31, 2026. The synopses below generally provide the total spend for each  
20 line item the Company requests in this rate case and the details regarding breakout  
21 by historical period, projected bridge period, and projected test period, are laid out  
22 in Exhibit A-12, Schedule B5.7.8, in columns d, g, and h. Figure 8 below represents  
23 a high-level view of capital allocation within the Sub-Portfolio.

Line  
No.

1

Figure 8 Enterprise Data Analytics – IT Investment



2

3

*a) Sustainment*

4

**Q67. What is the Enterprise Data Analytics Sub-Portfolio investment in the Sustainment category?**

5

6

**A67.** The Company is seeking recovery for \$9.7 million in the Sustainment Category of the Enterprise Data Analytics Sub-Portfolio over the 36 months ending December 31, 2026, and the historical spend of \$4.6 over 12 months ending December 31, 2023, as shown on line 1 and 2 of the Capital Expenditures Exhibit A-12, Schedule B5.7.8. These investments are described below.

10

11

12

(1) Enterprise Data Analytics Platform Application Health

13

The Company is seeking recovery for \$5.4 million into the Enterprise Data Analytics Platform Application Health project in the project over the 36 months

14

Line  
No.

1 ending December 31, 2026, and the historical spend of \$4.6 million over 12 months  
2 ending December 31, 2023, as shown on line 1 of Exhibit A-12, Schedule B5.7.8.

3  
4 This is a multi-year investment that will improve and enhance technology stacks to  
5 mature enterprise data platform needs and invest in modern analytics tools and  
6 programs for better reporting and decision-making capabilities. The scope of the  
7 2023 Advance and Enhance the Enterprise Data Platform project has been  
8 incorporated into the Enterprise Data Analytics Platform Application Health  
9 project.

10  
11 The Company reports a variance of \$2.4 million more in the 36 months ending  
12 December 31, 2025, than was approved for cost recovery in Case No. U-21534. Of  
13 this amount, \$1.0 million reflects the disallowances of 10% for 2023 and 20% for  
14 2024 and 2025 directed by the Case No. U-21534 Final Order. The remaining \$1.4  
15 million is to support reworking of the environment setup for Customer Operational  
16 Data Store (CODS), resulting in reloading, and revalidating data. Additionally, a  
17 data repository was established to store Personally Identifiable Information (PII),  
18 supporting the new design pattern for confidential information storage. See Exhibit  
19 A-24, Schedule N3 Lines 308 - 311 for additional project details.

20

21 (2) Enterprise Data Analytics – Alteryx and Qlik License Renewal

22 The Company is seeking recovery for \$4.3 million into the Enterprise Data  
23 Analytics - Alteryx and Qlik License Renewal project over the 12 months ending  
24 December 31, 2026, as shown on line 2 of Exhibit A-12, Schedule B5.7.8.

Line  
No.

1 This investment supports ongoing Qlik and Alteryx relicensing costs. Renewing  
2 the three-year Qlik license in 2026 will allow the Company to maintain real-time  
3 transactional and reporting capabilities for SAP Customer and Billing data.  
4 Renewing the Alteryx license will continue to empower end users with a self-  
5 service tool for data blending, enabling independent data access and analysis, which  
6 enhances decision-making speed and reduces the burden on data teams.  
7 Implementing these changes will enhance the EDA cloud data platform cost-  
8 effectively. The solution aims to provide near-real-time SAP Customer Billing data  
9 access without disrupting SAP ISU/CRM production environments, seamlessly  
10 replicate master data and functional tables to Azure PaaS services, support robust  
11 monitoring for new data sources, facilitate blending of SAP and non-SAP data for  
12 operational reporting and accuracy verification, mitigate technical debt on the  
13 current CR&B system, and add table definitions to the Data Catalog for easier data  
14 discovery and inventory management. See Exhibit A-24, Schedule N3 Line 312 for  
15 additional project details.

16

17 *b) Strategic*

18 **Q68. What is the Enterprise Data Analytics Sub-Portfolio investment in the**  
19 **Strategic category?**

20 A68. The Company is seeking recovery for \$0.4 million in the Strategic category of the  
21 Enterprise Data Analytics Sub-Portfolio over the 12 months ending December 31,  
22 2024, shown on line 3 of exhibit A-12, Schedule B5.7.8. The investment in this  
23 category is described below.



Line  
No.

1 (1) DO Productivity Center

2 The Company is seeking recovery for \$0.4 million in the DO Productivity Center  
3 project over the 12 months ending December 31, 2024, shown on line 3 of Exhibit  
4 A-12, Schedule B5.7.8.

5

6 This six-month investment designed and implemented a Performance Center for  
7 Distribution Operations (DO), with the objective of providing a sufficiently  
8 accurate picture of productivity and performance for Blue Sky and Grey Sky work.

9 The project created a central reporting location and provided consistency of  
10 productivity metric measurement across DO. With this foundational data and  
11 dashboard visualization, DO will be able to identify and measure further  
12 productivity improvement initiatives. See Exhibit A-24, Schedule N3 Line 313 for  
13 additional project details.

14

15 *5. Innovations*

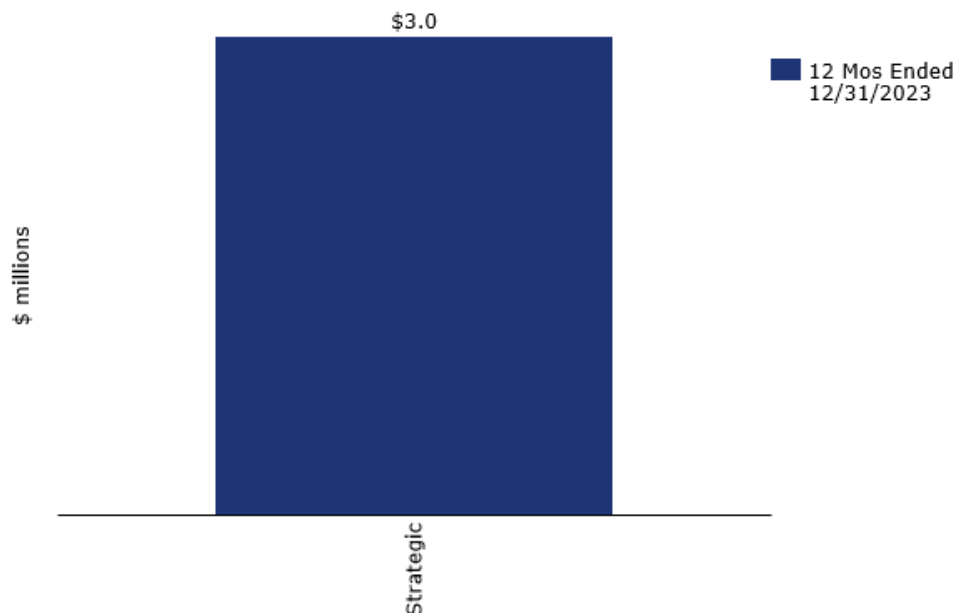
16 **Q69. Can you summarize the Innovation Sub-Portfolio investment?**

17 A69. The Company seeks recovery of its \$3.0 million Innovation Sub-Portfolio  
18 investment during the 12 months ending December 31, 2023, as shown in line 1 of  
19 the Capital Expenditures - Exhibit A-12, Schedule B5.7.9. Figure 9 below  
20 represents the capital allocation within the Sub-Portfolio.

Line  
No.

1

Figure 9 Innovations – IT Investment



2

*a) Strategic*

3

**Q70. Are there additional details for the Innovation Sub-Portfolio investment?**

4

A70. Yes. The DTE Applied Innovation Team provides capability and capacity from in-house DTE leaders and subject matter experts, and external consultants with key technology, entrepreneurial, innovation management, and communications expertise. The scope of work under this investment is described below:

5

6

7

8

9

10

11

12

13

14

DO - CBC-8000 Automated Service Now Tickets from Maximo: Historically, the Company employed a manual process to connect DO Work Management and IT Work Management systems to enable CBC-8000 installations. DO engineering utilizes Maximo for issuing work orders for the installation of capacity controls by region. This work requires IT network engineering tasks to be generated from ServiceNow. This project was designed to improve the CBC-8000 installation by

Line  
No.

1 automating ServiceNow tickets from Maximo via an Application Programming  
2 Interface. There are 3000-5000 CBC-8000 devices expected to be deployed, and all  
3 deployments will utilize this newly developed efficiency and quality measure. The  
4 new process integrates Maximo work orders into ServiceNow IT tickets, thereby  
5 allowing the two systems to communicate. When a workorder is created in  
6 Maximo, a ServiceNow request is triggered, and updates are communicated  
7 between the two systems. The new process can be utilized for any small or large-  
8 scale SCADA Devices deployment in the future, which represents more than 3000  
9 devices annually that will utilize this newly developed efficiency and quality  
10 measure. Considering an example of 3000 devices, approximately 15 minutes per  
11 request saves 45,000 minutes (750 hours). This also saves 10% manual entry errors,  
12 preventing 300 errors for 3000 devices. This solution increases efficiency and  
13 dependability, due to the removal of human error and decreasing the time it takes  
14 to manually enter ServiceNow tickets from Maximo.

15

16 Weather Network Sensors and All Sky Imaging: The primary objective of this  
17 project is to assess the current weather equipment landscape across DO to aid in  
18 research of cost-effective products that can help DTE predict solar generation with  
19 greater accuracy. The intent of the project aimed to explore weather collection  
20 sensors and sky imagers capable of capturing solar radiation, ambient temperatures,  
21 wind speed, and cloud cover. Older aging technology deployed across the service  
22 territory is limited [in its ability to accurately capture solar generation data leading  
23 to overly generalized data that could impact the accuracy of solar generation and  
24 load prediction forecasts. This project compared and contrasted DTE's older  
25 operational technology and the new technology available on the market. The

Line  
No.

1 experiment evaluated six different products over a one-month period; the selected  
2 product will allow the Company to better predict solar generation at large and small  
3 gateway stations and involve fewer mechanical parts, which reduces year-over-year  
4 maintenance costs and utilizes newer technology that measures temperature,  
5 radiation, radio wave emissions, and lightning strikes.

6 See Exhibit A-24, Schedule N3 Line 314 for additional project details.

7

8 **B. Corporate Applications**

9 **Q71. What are the projected costs for investments in the Corporate Applications**  
10 **Portfolio?**

11 A71. As reflected on Line 2 of Exhibit A-12, Schedule B5.7, page 1, capital expenditures  
12 for Corporate Applications total \$10.7 million for the historical test year ended  
13 December 31, 2023, \$21.9 million in the projected 24-month bridge period ending  
14 December 31, 2025, and \$15.2 million for the projected test period ending  
15 December 31, 2026.

16

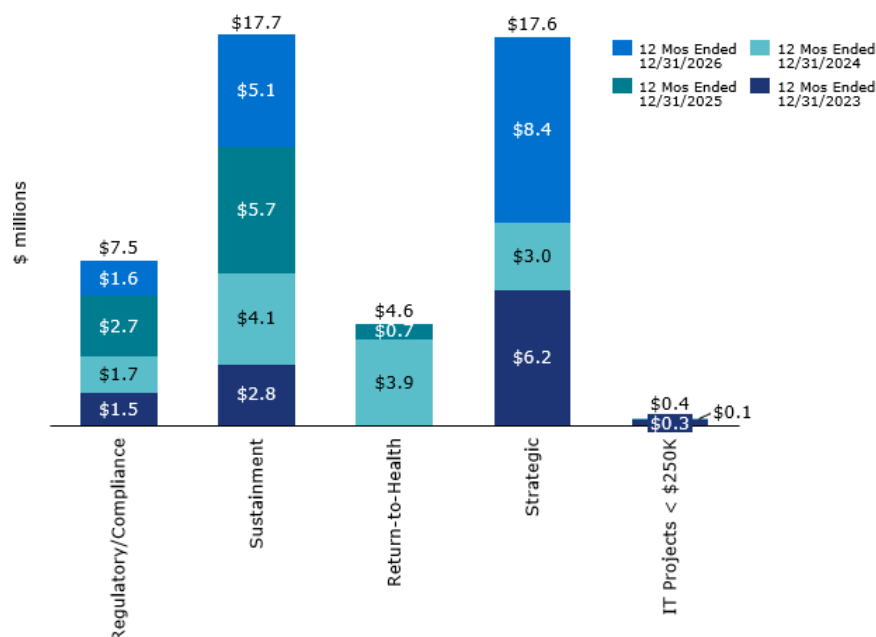
17 The synopses below provide the total spend for each line item the Company  
18 requests in the instant case, and the cost details for projects in this Portfolio broken  
19 out by historical period, projected bridge period, and projected test period, are  
20 provided in Exhibit A-12, Schedule B5.7.1, in columns (d), (g) and (h),  
21 respectively. Figure 10 represents a high-level view of capital allocation within the  
22 Portfolio.

Line  
No.

1

Figure 10 Corporate Applications – IT Investment

2



3

## a) Regulatory/Compliance

4

**Q72. What are the Corporate Applications investments in the Regulatory/Compliance category?**

5

6

**A72.** The Corporate Applications Portfolio is seeking recovery for \$6.0 million in the Regulatory/Compliance category over the 36 months ending December 2026 and the historical spend of \$1.5 million over the 12 months ending in December 2023, as shown in lines 1 through 3 of the Capital Expenditures - Exhibit A-12, Schedule B5.7.1. These investments are described below.

10

11

12

## 1) Core ERP Stacks and Packs

13

The Company is seeking recovery for \$4.5 million in the Core ERP Stacks and Packs project over the 36 months ending December 31, 2026, and the historical spend of \$1.5 million over the 12 months ending in December 31, 2023, as shown on line 1 of Exhibit A-12, Schedule B5.7.1.

16

Line  
No.

1 DTE's Core Enterprise Resource Planning (ERP) platform – the SAP ERP system  
2 – supports all resource planning processes and systems for the Corporate Services,  
3 Human Resources (HR), and Finance Organizations. Examples of critical processes  
4 that SAP supports are Financial Close, Financial Asset Management, Financial  
5 Reporting, Time Management, Payroll Processing, Purchasing, and Tax  
6 Management. There are also critical integrations that support Customer Billing and  
7 Asset and Work Management. The SAP ERP system requires regular support pack  
8 patching to ensure that it remains updated with the necessary software and platform  
9 support to comply with legal and regulatory requirements for payroll, benefits, and  
10 HR reporting, meet corporate reporting mandates, and minimize outages by  
11 aligning all required patching within the same outage window. The Core ERP  
12 Stacks and Packs project is a recurring annual investment to ensure that the SAP  
13 ERP system is up to date with the latest required support packs and stacks. See  
14 Exhibit A-24, Schedule N3 Lines 1 - 4 for additional project details.

15

16 2) Secure 2.0 Act for 401K

17 The Company is seeking recovery for \$0.2 million in the Secure 2.0 Act for 401K  
18 project over the 12 months ending December 31, 2024, as shown on line 2 of  
19 Exhibit A-12, Schedule B5.7.1.

20

21 The Secure 2.0 Act for 401K project enhances DTE employee retirement savings  
22 by expanding access, increasing savings rates, and simplifying plan rules. The  
23 project implements the changes contained in the SECURE 2.0 Act of 2022, which  
24 took effect after December 31, 2023: (1) all catch-up contributions to qualified  
25 retirement plans must be Roth contributions for employees earning more than

Line  
No.

1 \$145,0001, which encourages strategic retirement planning and potentially  
2 increases tax revenue; and (2) a unified election process for 401(k) tax rollovers,  
3 ensuring consistent Roth tax treatment. See Exhibit A-24, Schedule N3 Line 5 for  
4 additional project details.

5

6 3) Weekly Payroll – Davis Bacon Grant

7 The Company is seeking recovery for \$1.3 million in the Weekly Payroll – Davis  
8 Bacon Grant project over the 24 months ending December 31, 2025, as shown on  
9 line 3 of Exhibit A-12, Schedule B5.7.1.

10

11 This project permits DTE to leverage federal grants awarded under the Inflation  
12 Reduction Act of 2022 to transition to a weekly payroll system. This adjustment  
13 aligns with legislative requirements and ensures the funding grant that has been  
14 awarded under the Davis-Bacon Act is utilized. Implementing this change requires  
15 meticulous planning and resource allocation, ensuring long-term financial benefits  
16 and adherence to federal mandates. See Exhibit A-24, Schedule N3 Lines 6,7 for  
17 additional project details.

18

19 *b) Sustainment*

20 **Q73. What are the Corporate Applications investments in the Sustainment**  
21 **category?**

22 A73. The Corporate Applications Portfolio is seeking recovery for \$14.9 million in the  
23 Sustainment category over the 36 months ending December 31, 2026, and the  
24 historical spend of \$2.8 million over the 12 months ending December 31, 2023, as

Line  
No.

1 shown in line 4 through line 10 of the Capital Expenditures - Exhibit A-12,  
2 Schedule B5.7.1. These investments are described below.

3

4 1) Corporate Services Application Health

5 The Company is seeking recovery for \$2.2 million in the Corporate Service  
6 Application Health project over the course of the 36 months ending December 31,  
7 2026, and the historical spend of \$0.7 million over 12 months ending in December  
8 31, 2023, as shown on line 4 of Exhibit A-12, Schedule B5.7.1.

9

10 The Corporate Service Application Health project is an ongoing annual investment  
11 that will continue in 2026 to upgrade and ensure the health, reliability, and security  
12 of a suite of 40 applications within the Corporate Applications Portfolio that run on  
13 unsupported infrastructure and operating systems. These applications, including  
14 mail services, fleet and fuel management, and emissions monitoring, among others,  
15 support several organizations within the Company, including Supply Chain and  
16 Environmental Management and Safety. This investment permits DTE to  
17 implement hardware and environment upgrades, continue information security  
18 enhancements, and implement vendor software changes to ensure that IT assets  
19 avoid outages or disruption to business processes that could occur due to  
20 component failure, security issues, or incompatibility with newer components. This  
21 project also helps the Company ensure that appropriate vendor support is  
22 maintained for these assets.

23

24 The Company reports a variance of \$0.4 million more for the 24 months ending  
25 December 31, 2025, than was approved for cost recovery in Case No. U-21534, due



Line  
No.

1 to the disallowances of 10% in 2023 and 20% in 2024 and 2025 directed by the  
2 Case No. U-21534 Final Order. See Exhibit A-24, Schedule N3 Lines 8 - 11 for  
3 additional project details.

4

5 2) Documentum (EDM) Application Health

6 The Company is seeking recovery for \$1.6 million in the Documentum (Enterprise  
7 Document Management) Application Health project over the 36 months ending  
8 December 31, 2026, and the historical spend of \$0.1 million in 2023, as shown on  
9 line 5 of Exhibit A-12, Schedule B5.7.1.

10

11 The Documentum Application Health project is an annual investment that will  
12 continue in 2026 to maintain the Documentum platform. Documentum is a  
13 supported interface to work management system and serves as an electronic  
14 repository connects with the Company's work management system, providing user  
15 access to documents while executing work orders. As defined by DTE's Document  
16 Management Governance Board, the Company has an aligned strategy across the  
17 enterprise to address gaps in how documents are received, processed, reviewed,  
18 approved, stored, retrieved, and eventually purged. The investment ensures that the  
19 Documentum platform remains secure and available to meet document repository  
20 objectives in support of DTE's defined document management strategy and covers  
21 implementation support for security vulnerability remediation, system upgrades,  
22 value added enhancements, and organic system growth (sizing). See Exhibit A-24,  
23 Schedule N3 Lines 12 - 15 for additional project details.

24

25 3) Enterprise Applications Health

Line  
No.

1 The Company is seeking recovery for \$2.3 million in the project over the 36 months  
2 ending December 31, 2026, and the historical spend of \$0.6 million in 2023, as  
3 shown on line 6 of Exhibit A-12, Schedule B5.7.1.

4

5 The Enterprise Applications Health project is an annual investment that will  
6 continue in 2026. The project encompasses maintenance of 24 critical applications,  
7 including Primavera, Captiva, RightPax, Maxavera, and RightFax, that are integral  
8 to supporting DTE's Finance, Legal, and Major Enterprise Projects Organizations.

9 This investment prioritizes keeping these applications updated and security-  
10 patched. The benefits of this project are safeguarding these applications against  
11 outages or disruptions that might arise from IT component failures, security  
12 vulnerabilities, or incompatibility with newer technologies, ensuring strict  
13 adherence to regulatory requirements such as those mandated by NERC, and  
14 maintaining appropriate vendor support. Over the next few years, this project will  
15 focus on upgrading the PACS OnGuard system and ensure the completion of  
16 monthly patches.

17

18 The Company reflects a variance of \$1.2 million more in the 24 months ending  
19 December 31, 2024, than was approved for cost recovery in Case No. U-21534. Of  
20 this amount, \$0.2 million is due to the disallowances of 10% in 2023 and 20% in  
21 2024 directed by the Case No. U-21534 Final Order. The remaining \$1.0 million is  
22 for additional scope to support badging and exchange files with banks (EDI) and  
23 Primavera P6 project scheduling capabilities. See Exhibit A-24, Schedule N3 Lines  
24 16 - 19 for additional project details.

Line  
No.

1           4)     Enterprise Resource Planning (ERP)

2           The Company is seeking recovery for \$3.9 million in the Enterprise Resource  
3           Planning (ERP) project over the 36 months ending December 31, 2026, and the  
4           historical spend of \$0.3 million in 2023, as shown on line 7 of Exhibit A-12,  
5           Schedule B5.7.1.

6

7           The Enterprise Resource Planning (ERP) project is an annual investment that will  
8           continue in 2026. The ERP system is a core platform that supports all resource  
9           planning processes and systems that are also supported through the SAP platform  
10          for Corporate Services, Human Resources, and Finance Organizations. This  
11          investment ensures that the ERP system is maintained and includes monthly  
12          releases to upgrade end-of-life systems, completion of essential critical system  
13          failover testing, and enhancements to associated applications to accommodate  
14          evolving business processes within these organizations.

15

16          The Company reports a variance of \$0.7 million more for the 36 months ending  
17          December 31, 2025, than was approved for cost recovery in Case No. U-21534. Of  
18          this amount, \$0.5 million is due to the 10% disallowance in 2023 and 20%  
19          disallowance in 2024 and 2025, as directed by the Case No. U-21534 Final Order.  
20          The remaining \$0.2 million is due to the additional scope to upgrade Solution  
21          Manager as it was out of support and posing a security risk to the environment due  
22          to an unsupported java version. See Exhibit A-24, Schedule N3 Lines 20-23 for  
23          additional project details.

Line  
No.

1           5)       Financial Applications Health

2           The Company is seeking recovery for \$1.7 million in the Financial Applications  
3           Health project over the 36 months ending December 31, 2026, and the historical  
4           spend of \$0.2 million in 2023, as shown on line 8 of Exhibit A-12, Schedule B5.7.1.

5

6           The Financial Applications Health project is an annual investment that will  
7           continue in 2026. This project provides regular updates to 21 applications vital for  
8           the health, reliability, and security of DTE's financial systems.

9

10          The Company reports a variance of \$1.0 million more in the 36 months ending  
11          December 31, 2025, than was approved for cost recovery in Case No. U-21534. Of  
12          this amount, \$0.1 million is due to the disallowances of 10% in 2023 and 20% in  
13          2024 and 2025 directed by the Case No. U-21534 Final Order. The remaining \$0.9  
14          million is due to additional uplift charges from Power Plan, to continue to track  
15          additional assets (solar farms, power plants, fleet etc.) acquired by DTE. See  
16          Exhibit A-24, Schedule N3 Lines 24 - 27 for additional project details.

17

18          6)       Human Resources Health Applications

19          The Company is seeking recovery for \$0.7 million in the Human Resources  
20          Applications Health project over the 36 months ending December 31, 2026, and the  
21          historical spend of \$0.3 million in 2023, as shown on line 9 of Exhibit A-12,  
22          Schedule B5.7.1.

23

24          The Human Resources Applications Health project is an annual investment that will  
25          continue in 2026. This project ensures the health and stability of Human Resources

Line  
No.

1 (HR) applications, including SuccessFactors Platform, OpenText, and Oracle  
2 backends, by conducting required upgrades to these applications to ensure they are  
3 running on supported infrastructure and replacing operating systems as needed.  
4 These upgrades ensure that each application is current and operating with the latest  
5 functions and features to support business processes. This project also supports the  
6 application configuration changes that are built, tested, and deployed through  
7 monthly change release to support Human Resources business process  
8 requirements. See Exhibit A-24, Schedule N3 Lines 28-31 for additional project  
9 details.

10

11 7) Production Growth

12 The Company is seeking recovery for \$2.5 million in the Production Growth project  
13 over the 36 months ending December 31, 2026, and the historical spend of \$0.5  
14 million in 2023, as shown on line 10 of Exhibit A-12, Schedule B5.7.1.

15

16 The Production Growth project is an annual investment that will continue in 2026.  
17 The scope of the project is the continuous expansion of DTE's computing  
18 environment in response to increasing demand on the Company's on-premise  
19 Corporate Application systems. The project covers infrastructure assets for  
20 computing power, storage capacity, database availability and middle tier  
21 infrastructure. See Exhibit A-24, Schedule N3 Lines 32-35 for additional project  
22 details.

Line  
No.

1                    *c) Return-to-Health*

2    **Q74. What is the Corporate Applications Portfolio investment in the Return-to-**  
3    **Health category?**

4    A74. The Corporate Applications Portfolio is seeking recovery for \$4.6 million in the  
5    Return-to-Health category over the 24 months ending December 31, 2025, as  
6    shown in lines 11 to 13 of the Capital Expenditures - Exhibit A-12, Schedule  
7    B5.7.1. These investments are described below.

8

9            1)      Cloud Health and Safety

10        The Company is seeking recovery for \$3.5 million in the Cloud Health and Safety  
11        project over the 24 months ending December 31, 2025, as shown online 11 of  
12        Exhibit A-12, Schedule B5.7.1.

13

14        The current DTE safety reporting systems lack integration, with predominantly  
15        lagging metrics that impede timely analysis. This project aims to implement SAP  
16        Environmental Health and Safety Management (EHSM) Incident Management  
17        (IM) S/4 HANA, encompassing the standard IM application, a Fiori application  
18        with Dynamic Forms, and utilizing Standard Dashboards in SAP Analytics Cloud.  
19        An efficient and streamlined safety reporting system will enhance the accuracy of  
20        data collection, thereby improving the effectiveness of the investigative process for  
21        root cause analysis and mitigation actions.

22

23        The Company reports a variance of \$1.0 million more for the 24 months ending  
24        December 31, 2025, than was approved for cost recovery in Case No. U-21534. Of  
25        this amount, \$0.5 million is due to a 20% disallowance in 2024 and 2025 as directed

Line  
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1 by the Case No. U-21534 Final Order. The remaining \$0.5 million is due to an  
2 addition of the Quality Assurance environment that was not included in the SAP  
3 contract for this project. See Exhibit A-24, Schedule N3 Lines 36, 37 for additional  
4 project details.

5

6 2) Environmental Air Regulation Management

7 The Company is seeking recovery for \$0.3 million in the Environmental Air  
8 Regulation Management project over the 12 months ending December 31, 2025, as  
9 shown on line 13 of Exhibit A-12, Schedule B5.7.1.

10

11 DTE currently utilizes the Opsinfo application for regulatory air emission reports  
12 and voluntary environmental, social, and governance (ESG) reporting. The shift of  
13 Opsinfo to a cloud-based platform has rendered the Company's existing on-  
14 premises software outdated, non-upgradable, and vulnerable to security threats.  
15 Consequently, the DTE Environmental Team depends on an external consulting  
16 firm to manually consolidate emissions data and execute complex chemical  
17 calculations for over sixty compliance reports annually. Recognizing the need to  
18 address security concerns, ensure compliance with regulatory and voluntary  
19 standards, and support robust and sustainable ESG reporting, through the  
20 Environmental Air Regulation Management project DTE will replace the obsolete  
21 Opsinfo application with the Sphera Cloud application. The new system will be  
22 used for future air and greenhouse gas emissions reporting, including Michigan Air  
23 Emissions Reporting System (MAERS), Toxic Release Inventory (TRI),  
24 greenhouse gas (GHG), new source review (NSR), and air permit reports. The  
25 implementation of Sphera will ensure DTE's continued compliance and establish a

Line  
No.

1 robust and sustainable reporting process. See Exhibit A-24, Schedule N3 Line 39  
2 for additional project details.

3

4 *d) Strategic*

5 **Q75. Please explain the Corporate Applications Portfolio investment in the**  
6 **Strategic category.**

7 A75. The Company is seeking recovery for \$11.4 million in the Strategic category of the  
8 Corporate Applications Portfolio over the 36 months ending December 31, 2026,  
9 and the historical spend of \$6.2 million over the 12 months ending December 31,  
10 2023, as shown in lines 14 through 21 of the Capital Expenditures - Exhibit A-12,  
11 Schedule B5.7.1. These investments are described below.

12

13 1) Enterprise Automation

14 The Company is seeking recovery for the historical spend of \$6.2 million in the  
15 Enterprise Automation project over the 12 months ending December 31, 2023, as  
16 shown on line 14 of Exhibit A-12, Schedule B5.7.1.

17

18 The Enterprise Automation project supports digitization and automation initiatives  
19 for organizations across the DTE enterprise. The initiatives involve automating  
20 routine tasks and processes, digitizing previously paper-based documents and  
21 processes, or producing a platform to standardize, optimize, and/or bring  
22 productivity and new capabilities to processes and procedures. This includes  
23 providing the ability to perform reporting and data analytics, relevant to the  
24 processes digitized, through dashboarding tools. Common digitization initiatives  
25 include building forms-based apps, for both mobile and desktop use cases, and



Line  
No.

- 1 creating visualizations or dashboards for reporting and data analytics use cases.
- 2 Common automation initiatives include creating Robotic process Automation
- 3 (RPA) to perform routine tasks and processes.
- 4 • Enterprise Automation – Digitization: The key automation efforts under this
- 5 project include.
- 6 ○ Preventative Maintenance (PMs) - Vehicle Locator: To enable Fleet
- 7 Garage Mechanics to geographically locate vehicles that require
- 8 preventative maintenance.
- 9 ○ Incoming Commitments Communications: To send proactive Low
- 10 Income Self Sufficiency and Agency Funding communications to
- 11 eligible customers. The solution will trigger the relevant
- 12 communications to the customer's email. The communications will
- 13 include information about LSP and Agency funding available and
- 14 how to avail them. The solution will need to run daily at a fixed
- 15 schedule.
- 16 ○ I Can Help!: To replace the I Can Help! eForm with an app that will
- 17 also be accessible on the field.
- 18 ○ High Bill Alert: To update High Bill Alerts automation to account
- 19 for Time of Day changes.
- 20 ○ Procurement Non-Regulatory Redux: Different business users
- 21 across the organization enter invoices in the Prodagio application.
- 22 Currently, there are 6 Invoice processing automations with 4 using
- 23 Prodagio. With the removal of Prodagio, these legacy automations
- 24 have to be re-designed using the Microsoft Power Platform Suite for
- 25 the non-regulatory organization.

Line  
No.

- 1                   ○ Digital Solutions Reporting: This solution is a series of queries and
- 2                   dashboards for the Company's Apps developed within Enterprise
- 3                   Automation. The dashboard and queries give insight into
- 4                   performance and usage metrics on the Company's applications,
- 5                   including volume and cases, number of users, and level of adoption.
- 6
- 7                   • Enterprise Automation - Customer Service Virtual Agent: The Customer
- 8                   Service Virtual Agent (VA) is a transformational initiative to enhance
- 9                   customer experience by leveraging AI-enabled conversational interaction
- 10                  with customers to seamlessly complete transactions. The VA converses
- 11                  with customers to handle routine and recurring transactions, including
- 12                  Move-Out (Stop Service), High Bill Inquiry, Promise to Pay, Move-In
- 13                  (Start Service), and Transfers. Customers can utilize the VA as a self-
- 14                  service option. The VA screens incoming customer calls and also
- 15                  completes calls without Contact Center intervention.
- 16                  • Enterprise Automation - Process Automation:
- 17                   ○ Meter Reading Order Read Failures: Daily, an automation will
- 18                   generate the current day read failures and perform the necessary
- 19                   steps to re-request the read.
- 20                   ○ Blade Robotic Desktop Automation (RDA) to Robotic Process
- 21                   Automation (RPA) Conversion: The Blade Un-Billed report will
- 22                   convert from RDA to RPA, following the same steps with key
- 23                   changes: it will auto-generate by the RDA/BOT instead of manually

Line  
No.

1 and will use Blade Late Invoicing Milestone reports as the source  
2 instead of Blade Late Billing Milestone reports.

3 • Enterprise Automation - Customer Service Agent Assist: The Customer  
4 Service Agent Assist Platform is a key transformational initiative to  
5 empower Contact Center Customer service Representatives (CRs), by  
6 automating manual and time-consuming tasks during, before, or after a call.  
7 CRs are provided with a web interface hosting a suite of use cases that  
8 allows CRs to automate call handling tasks and perform transactions much  
9 faster. This will reduce Average handle Time (AHT) of the call, improve  
10 First call Resolution (FCR), reduce time for customers, thereby enabling a  
11 better customer experience. The Agent Assist Platform receives over 7,000  
12 hits per day, from 600 end users.

13

14 See Exhibit A-24, Schedule N3 Line 40 for additional project details.

15

16 2) Enhanced Document Management Capability

17 The Company is seeking recovery for \$0.3 million in the Enhanced Document  
18 Management Capability project over the 12 months ending December 31, 2024 as  
19 shown on line 15 of Exhibit A-12, Schedule B5.7.1.

20

21 The Document Management Governance Board outlined a phased strategy to  
22 enhance the document management system by automating workflows, integrating  
23 with key tools, digitizing and indexing records, improving search and collaboration,  
24 and establishing retention policies.

Line  
No.

1 The Company reflects a variance of \$3 million less in the 24 months ending  
2 December 31, 2025, than approved for cost recovery in Case No. U-21534 due to  
3 deferral of the project implementation schedule. During the initial phases of project  
4 implementation, the Company identified significant concerns with the approach  
5 employed by the implementation partner, which was unable to deliver within the  
6 approved budget and unlikely to meet the agreed upon project milestones. As a  
7 result, DTE has paused this project and will reevaluate the vendor and the approach  
8 in 2027 to ensure better alignment with the Company's near-term and long-term  
9 strategic goals. See Exhibit A-24, Schedule N3 Line 41 for additional project  
10 details.

11

12 3) Industrial Hygiene

13 The Company is seeking recovery for \$0.8 million in the Industrial Hygiene project  
14 over the 12 months ending December 31, 2026, as shown on line 16 of Exhibit A-  
15 12, Schedule B5.7.1.

16

17 The SAP Environmental Health and Safety Management (EHSM) Health & Safety  
18 module facilitates the association of employee exposure and medical data to  
19 perform health risk assessments, adhering to the standards set by the American  
20 Industrial Hygiene Association (AIHA) for Certified Industrial Hygienists. DTE  
21 Energy plans to enhance its Safety program by implementing the SAP EHS  
22 Industrial Hygiene (IH) solution, part of the SAP EHSM Health & Safety module  
23 on the S/4 HANA platform. This project will provide an integrated system for  
24 managing industrial hygiene campaigns, including the measurement, collection,  
25 and validation of analytes. It will also enable the planning and tracking of sampling

Line  
No.

1 campaigns, IH equipment calibration through SAP PM, and data input from users  
2 or lab uploads. The project will utilize a comprehensive database for storing  
3 exposure data, combined with HR employee demographic data, and the  
4 Incident/Accident (I/A) system used by Corporate Safety, Medical Services, and  
5 the Company's workers' compensation carrier. See Exhibit A-24, Schedule N3  
6 Line 42 for additional project details.

7

8 4) Real Estate Management

9 The Company is seeking recovery for \$2.6 million in the Real Estate Management  
10 project over 12 months ending December 31, 2026, as shown on line 18 of Exhibit  
11 A-12, Schedule B5.7.1.

12

13 Through this project, DTE is launching the SAP Real Estate initiative to streamline  
14 property leasing, taxation, and legal boundary verification. Currently, accessing  
15 legal documents such as lease contracts, easement drawings, and real estate  
16 transactions is manual and time-consuming due to their storage in multiple  
17 repositories. The Real Estate Management project will implement the SAP Capital  
18 Lease Management (CLM) module and integrate the CLM module with the existing  
19 SAP Employee Central Component, Documentum, and the future SAP S/4 Hana  
20 implementation. This integration will enhance productivity and support sustainable  
21 property Portfolio management by eliminating manual, time-consuming tasks and  
22 providing Real Estate employees with a single repository to access documents and  
23 more effectively support Corporate Legal, Tax, Renewable, Gas, and Electric Field  
24 personnel. See Exhibit A-24, Schedule N3 Line 44 for additional project details.

Line  
No.

1           5)       Time Entry and Payroll

2           The Company is seeking recovery for \$5.0 million in the Time Entry and Payroll  
3           project over the 12 months ending December 31, 2026, as shown on line 19 of  
4           Exhibit A-12, Schedule B5.7.1.

5  
6           Time Entry and Payroll project is a multi-year year project starting in 2026. This  
7           project will implement the SAP Time Management and SAP Employee Central  
8           Payroll applications, replacing the current SAP Enterprise Resource Planning  
9           (ERP) payroll system implemented in April 2007. This effort will modernize DTE's  
10          payroll and time management systems, resulting in a more efficient and streamlined  
11          experience for employees and supporting the Company's commitment to  
12          innovation and operational excellence. The cloud-based SAP Time Management  
13          application by WorkForce will serve as the system of record for time management,  
14          integrated with multiple business unit interfaces and third-party systems. This  
15          transformation will unify the current environment, which comprises a cloud-based  
16          HR system and an SAP legacy system, into a cohesive cloud-based solution for all  
17          employee groups. Similarly, the cloud-based SAP Payroll application will replace  
18          the Company's current on-premises SAP legacy payroll environment. It will  
19          integrate with multiple business units, external interfaces, and third-party systems,  
20          creating a unified cloud-based enterprise solution that includes time entry, BSI tax  
21          software, benefits, and compensation systems. This aspect of the project  
22          incorporates the work previously planned for the SAP Employee Central Payroll  
23          project. Therefore, it has been determined to implement the SAP Employee Central  
24          Payroll project with the Time Entry and Payroll investment to optimize integration

Line  
No.

1 and testing capabilities and deployments. See Exhibit A-24, Schedule N3 Line 45  
2 for additional project details.

3 6) Transparency Electric Data

4 The Company is seeking recovery for \$1.8 million in the Transparency Electric  
5 Data project over the 12 months ending December 31, 2024, as shown on line 20  
6 of Exhibit A-12, Schedule B5.7.1.

7

8 The Company's customers and stakeholders are increasingly seeking more robust  
9 data on both grid reliability and planned investments. Importantly, customers and  
10 stakeholders have expressed a desire to have this data provided in a localized  
11 manner, so that customers or communities can understand circuit performance and  
12 investments in their neighborhoods. To meet this need in a way that allows  
13 customers and stakeholders ready access to localized data on grid performance and  
14 grid investments, the project sets out to provide:

- 15 • Design and develop an improved intuitive, easy-to-find, and customer  
16 friendly Electric Grid Investment Map.  
17
- 18 • Design and develop an easy-to-use, flexible, "one-stop shop" platform that  
19 simplifies reliability and investment data access between internal business  
20 units.  
21

22 The Company reports a variance of \$0.4 million more in the 12 months ending  
23 December 31, 2024, than was approved for the cost recovery in Case No. U-21534,  
24 primarily due to the 20% disallowance directed by the Case No. U-21534 Final  
25 Order. See Exhibit A-24, Schedule N3 Line 46 for additional details.

Line  
No.

1 7) Warehouse Efficiency

2 The Company is seeking recovery for \$0.5 million in the Warehouse Efficiency  
3 project over the 12 months ending December 31, 2024, as shown on line 21 of  
4 Exhibit A-12, Schedule B5.7.1.

5

6 Shipping delays and product availability have significantly increased lead times for  
7 critical materials. DTE Planners and Schedulers need better visibility into  
8 contractor-sent and installable materials. The current SAP system does not track  
9 direct-to-contractor shipments or internal warehouse transfers, causing stockpiling  
10 and backlog. This project aims to implement barcoding and RFID technologies to  
11 improve material tracking and enhance SAP SRM for managing inventory.

12

13 The Company reports a variance of \$0.3 million more in the 12 months ending  
14 December 31, 2024, than was approved for the cost recovery in Case No. U-21534,  
15 primarily due to the purchase of additional hardware equipment to support material  
16 tracking. See Exhibit A-24, Schedule N3 Line 47 for additional details.

17

18 **C. Plant & Field**

19 **Q76. What are the projected costs for investments in the Plant & Field Portfolio?**

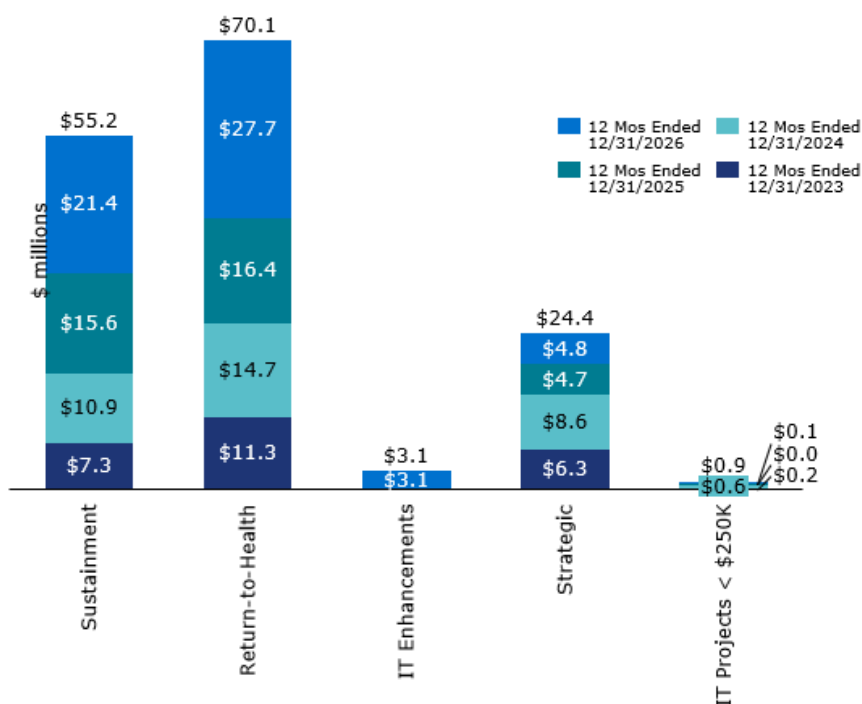
20 A76. As reflected on Line 4 of Exhibit A-12, Schedule B5.7, page 1, capital costs for  
21 Plant & Field total \$25.0 million for the historical test year ended December 31,  
22 2023, \$71.5 million in the bridge period (for the 24 months ending December 31,  
23 2025), and \$57.2 million for the projected test period ending December 31, 2026.



Line  
No.

The synopses below provide the total spend for each line item involved in the Company's request for recovery in this rate case. The cost details for projects in this Portfolio broken out by historical period, projected bridge period, and projected test period are provided in Exhibit A-12, Schedule B5.7.4, in columns d, g and h, respectively. Figure 11 represents a high-level view of capital allocation within the Portfolio.

Figure 11 Plant & Field – IT Investment



a) Sustainment

**Q77. Please explain the Plant & Field Portfolio investment in the Sustainment category.**

**A77.** The Company is seeking recovery for \$47.9 million in the Sustainment category over the 36 months ending December 31, 2026, and the historical spend of \$7.3

Line  
No.

1 million over 12 months ending December 31, 2023, as shown in lines 1 through 19  
2 of the Capital Expenditures Exhibit A-12, Schedule B5.7.4. These investments are  
3 described below.

4  
5 1) Advance Metering Infrastructure Application Health

6 The Company is seeking recovery for \$2.4 million in the Advance Metering  
7 Infrastructure Application Health project over the 24 months ending December 31,  
8 2025, and the historical spend of \$0.3 million in 2023, as shown on line 1 of Exhibit  
9 A-12, Schedule B5.7.4.

10

11 The current AMI system necessitates manual procedures for failover to alternate  
12 systems, which limits flexibility and requires human intervention. This project aims  
13 to develop a redundant system that will facilitate maintenance and repairs without  
14 necessitating planned outages. The multi-year project is specifically designed to  
15 enable automatic failover between each of the data centers, including the essential  
16 hardware provisioning for the AMI Collection Engine (CE).

17

18 The Company reports a variance of \$1.5 million less in the 36 months ending  
19 December 31, 2025, than was approved for cost recovery in Case No. U-21534. Of  
20 this variance, \$0.8 million is due to the 10% disallowance in 2023 and 20%  
21 disallowance in 2024 and 2025, as directed by the Case No. U-21534 Final Order.  
22 Additionally, (\$2.3) million of the variance is due to reduction in project scope. The  
23 purchase of additional servers was reduced from the AMI Application health  
24 project and accounted for under the Advance metering Field Collection System  
25 project. See Exhibit A-24, Schedule N3 Lines 48 - 50 for additional project details.

Line  
No.

1           2)       ClickSoft Application Health

2           The Company is seeking recovery for \$1.2 million in the ClickSoft Application  
3           Health project over the 36 months ending December 31, 2026, and the historical  
4           spend of \$0.3 million in 2023, as shown on line 2 of Exhibit A-12, Schedule B5.7.4.

5

6           The ClickSoft Application Health application project is an annual investment that  
7           will continue in 2026. Clicksoft is a cloud-based application that the Company  
8           currently utilizes for providing operational visibility and efficiency for various  
9           businesses units, including Substation, Electric Field operations (EFO), Power  
10          Equipment and Relay testing (PERT), Revenue Management and Protection  
11          (RMP), Meter Reading, and OH/UG (Overhead and Underground). This project  
12          will provide maintenance, and the necessary upgrades required to sustain the  
13          existing Clicksoft systems until it is replaced. The investments details for the  
14          replacement of Clicksoft is provided in Section VI.C.b.7 of my testimony.

15

16          The Company reports a variance of \$0.2 million more in the 36 months ending  
17          December 31, 2025, than was approved for cost recovery in Case No. U-21534 due  
18          to the disallowances of 10% in 2023 and 20% in 2024 and 2025 directed by the  
19          Case No. U-21534 Final Order. See Exhibit A-24, Schedule N3 Lines 51-54 for  
20          additional project details.

21

22          3)       Distribution Operations Application Health

23          The Company is seeking recovery for \$3.9 million in the Distribution Operations  
24          Application Health project over the 36 months ending December 31, 2026, and the

Line  
No.

1 historical spend of \$1.2 million in 2023, as shown on line 3 of Exhibit A-12,  
2 Schedule B5.7.4.

3

4 The Distribution Operations (DO) Application Health project is annual investment  
5 that will continue in 2026 supporting approximately 50 IT-supported applications  
6 within DO. The project includes adding new functionalities to systems such as  
7 Crew Management and Storm Restoration to accommodate evolving field  
8 operation needs, improve the mobile applications used by DO field workers, and  
9 enable efficient restoration work. Planned improvements include a redesigned  
10 Outage Status App with a Supervisory Dashboard, required enhancements to the  
11 Mobile Timesheet System, and infrastructure updates.

12

13 The Company reports a variance of \$0.9 million more in the 36 months ending  
14 December 31, 2025, than was approved for cost recovery in Case No. U-21534. Of  
15 this amount, \$0.6 million is due to the disallowances of 10% in 2023 and 20% in  
16 2024 and 2025 directed by the Case No. U-21534 Final Order. The remaining \$0.3  
17 million is due to the additional scope of upgrades to Application Programming  
18 Interfaces Management (APIM), crew management, Transport Layer Security  
19 (TLS) certification, and Redhat. See Exhibit A-24, Schedule N3 Line 55 - 58 for  
20 additional project details.

21

22 4) DTE Electric Generation Capacity Application Health

23 The Company is seeking recovery for \$1.8 million in the DTE Electric Generation  
24 Capacity Application Health project over the 36 months ending December 31,

Line  
No.

1 2026, and the historical spend of \$0.6 million in 2023, as shown on line 4 of Exhibit  
2 A-12, Schedule B5.7.4.

3  
4 The DTE Electric Generation Capacity Application Health project is an annual  
5 investment that ensures regular updates to the Generation Supply Management  
6 System (GSMS). This system calculates which generation plants to offer into the  
7 Midcontinent Independent System Operator (MISO) market, adhering to MISO  
8 regulations and remaining current with MISO Shadow Billing. The GSMS vendor  
9 targets quarterly releases for application updates which are crucial for compliance  
10 and financial planning. The project will also accommodate changes in MISO's  
11 back-end system, which could affect the GSMS's connectivity and interactions  
12 with MISO.

13  
14 The Company reflects a variance of \$0.4 million more in the 36 months ending  
15 December 31, 2025, than was approved for cost recovery in Case No. U-21534. Of  
16 this amount, \$0.3 million is due to the disallowances of 10% in 2023 and 20% in  
17 2024 and 2025 disallowances directed by the Case No. U-21534 Final Order. The  
18 remaining \$0.1 million is due to additional scope to replace end of life hardware on  
19 the Weblogic platform. See Exhibit A-24, Schedule N3 Lines 59 - 62 for additional  
20 project details.

21  
22 5) Enterprise Automation Support

23 The Company is seeking recovery for \$10.0 million in the Enterprise Automation  
24 Support project over the 24 months ending December 31, 2026, as shown on line 5  
25 of Exhibit A-12, Schedule B5.7.4.

Line  
No.

1 The Enterprise Automation Sustainment investment is crucial to maintain the  
2 automation solutions that have been implemented across the Company.  
3 Sustainment work focuses on addressing process and policy changes, asset  
4 depreciation, and feature enhancements to ensure all products remain functional  
5 and up to date. This initiative will maintain and improve the efficiency,  
6 functionality, and compliance of DTE's digital and automated solutions. Key areas  
7 of work include upgrading Blue Prism, Robotic Process automation (RPA)  
8 software from version 7.x to 8.x for better performance, monitoring, and coding  
9 capabilities, and re-basing and re-testing virtual machines and process automations.  
10 Work also includes modernizing over 30 Power Platform applications to prevent  
11 depreciation, reengineering Robotic Process Automations (RPAs) to enhance  
12 efficiency and reduce exceptions, updating safety and compliance applications, and  
13 enhancing the Customer Service – Agent Assist platform. See Exhibit A-24,  
14 Schedule N3 Lines 63, 64 for additional project details.

15

16 6) ESRI Application Health

17 The Company is seeking recovery for \$1.3 million in the ESRI Application Health  
18 project over the 36 months ending December 31, 2026, and the historical spend of  
19 \$0.3 million in 2023, as shown on line 6 of Exhibit A-12, Schedule B5.7.4.

20

21 The ESRI Application Health project is an annual investment that will continue in  
22 2026. This project supports enhancements to the Company's automated mapping  
23 system (Geographic Information System or GIS) that supports all GPS mapping  
24 data including operating maps and customer-facing outage maps. This investment  
25 includes procuring additional user licenses and testing and installing service packs

Line  
No.

1 and security vulnerability remediation as part of regularly scheduled release  
2 enhancements. Failure to deploy GPS releases would result in inaccurate mapping  
3 data. See Exhibit A-24, Schedule N3 Lines 65 - 68 for additional project details.

4

5 7) Everyday Daily Plan (EDDP) Application Health

6 The Company is seeking recovery for 0.4 million in the Everyday Daily Plan  
7 (EDDP) Application Health project over the 24 months ending December 31, 2026,  
8 as shown on line 7 of Exhibit A-12, Schedule B5.7.4.

9

10 Distribution Operations (DO) utilizes a unified Everyday Daily Plan (EDDP) web-  
11 based tool that seamlessly operates during both storm and non-storm conditions.  
12 This tool prioritizes daily work and efficiently assigns field crews to bundled work  
13 packages by integrating dispatch priorities for trouble work, configurable storm  
14 settings, and planned work priorities. The interface and functionality will remain  
15 consistent regardless of operational conditions, promoting ease of use and  
16 adaptability. This project will implement bug fixes and application monitoring to  
17 ensure the tool is operational and available 24/7. The EDDP tool will improve  
18 operational efficiency, customer satisfaction, and field crew effectiveness. See  
19 Exhibit A-24, Schedule N3 Lines 69, 70 for additional project details.

20

21 8) Fuel Supply Application Health

22 The Company is seeking recovery for \$1.3 million in the Fuel Supply Application  
23 Health project over the 36 months ending December 31, 2026, and the historical  
24 spend of \$0.4 million in 2023, as shown on line 8 of Exhibit A-12, Schedule B5.7.4.

Line  
No.

1 The Fuel Supply Application Health project is an annual investment that will  
2 continue in 2026. This project facilitates the management and enhancements of the  
3 Automated Rail Receipt (ARR) to manage inputs of coal, petcoke, and oil used by  
4 DTE's generation fleet. The ARR interfaces with data hosted by the vendor  
5 application Envision, which provides the location data of coal rail cars used by  
6 Corporate Fuel Supply. Energy Trading & Risk Management (ETRM) applications  
7 to deliver functions to plan natural gas purchasing, transportation, inventory  
8 management, nominating, and scheduling for the DTE gas fueled generation units.  
9 DTE began testing and deploying quarterly vendor releases to ETRM and AAR  
10 systems in 2022. Quarterly vendor releases to support these systems and three  
11 annual updates to maintain platform currency and introduce key enhancements are  
12 scheduled throughout 2026 and 2027. These upgrades are required to remain  
13 current under vendor support and provide new product capabilities to end users. In  
14 2026 specifically, the ARR and ETRM applications will receive new capabilities  
15 to automate workflows, enhance usability, and reduce redundancies in Fuel  
16 Supply's business processes. See Exhibit A-24, Schedule N3 Lines 71 - 74 for  
17 additional project details.

18

19 9) ITS-SRS Application Health

20 The Company is seeking recovery for \$1.8 million in the Information Technology  
21 System (ITS) Supervisory Control and Data Acquisition Realtime Support (SRS)  
22 Application Health project over the 24 months ending December 31, 2025, as  
23 shown on line 9 of Exhibit A-12, Schedule B5.7.4.



Line  
No.

1 The ITS-SRS Application Health Investment supports the core OSI (Open Systems  
2 Interconnection) system and vendor relationship used for grid operations. The ITS-  
3 SRS application also supports the NERC (North American Electric Reliability  
4 Corporation) compliance activities for ADMS (Advanced Distribution  
5 Management System), GMS (Generation Management System), and the MOC  
6 (Market Operations Center). Investment is required to keep these systems available  
7 and performing optimally, ensuring the smooth functioning of the electrical grid.

8

9 The Company reports a variance of \$0.5 million more in the 24 months ending  
10 December 31, 2025, than was approved for cost recovery in Case No. U-21534. Of  
11 this amount, \$0.3 million was due to the 20% disallowance directed by the Case  
12 No. U-21534 Final Order, and the remaining \$0.2 million is for the Avamar backup  
13 solution. Avamar is a daily backup solution required for disaster recovery of the  
14 SRS assets that are both NERC Low (Advanced Distribution Management System,  
15 consoles, Workstations, Servers, etc) and NERC High (The Generation  
16 Management System (GMS) and eSCADA (Wind Park Control) systems). NERC  
17 High cyber assets are those that, if compromised, could significantly impact the  
18 reliability or operability of the grid, particularly control centers and systems  
19 overseeing energy balancing, transmission, generation, and reliability monitoring.  
20 NERC Low assets meet the minimum bar of compliance to their set Critical  
21 Information Protection (CIP) standards. See Exhibit A-24, Schedule N3 Lines 75,  
22 76 for additional project details.

23

24 10) ITS ADMS Application Health

Line  
No.

1 The Company is seeking recovery for \$3.0 million in the Information Technology  
2 System (ITS) - Advanced Distribution Management System (ADMS) Application  
3 Health project over the 36 months ending December 31, 2026, as shown on line 10  
4 of Exhibit A-12, Schedule B5.7.4.

5  
6 The ITS ADMS Application Health Program covers a suite of applications that  
7 support safe and effective operation in the Electric System Operations Center  
8 (ESOC) and for Distribution Operations Dispatch. These applications include the  
9 Outage Management System (OMS), Distribution Management System (DMS),  
10 Energy management System (EMS), Generation Management System (GMS), and  
11 Systems Operations Management (SOM). This project provides support and  
12 updates to these applications and for integration infrastructure (ESB or Enterprise  
13 Service Bus) that connects all aspects of ADMS to DTE legacy systems. Investment  
14 in these required enhancements, upgrades, and maintenance reduces the risk of  
15 system failure or malfunction, which can have serious consequences on the safe  
16 and reliable operation of the electrical grid. See Exhibit A-24, Schedule N3 Lines  
17 77 to 79 for additional project details.

18

19 11) Maximo Application Health

20 The Company is seeking recovery for \$0.7 million in the Maximo Application  
21 Health project over the 12 months ending December 31, 2026, as shown on line 11  
22 of Exhibit A-12, Schedule B5.7.4.

23

24 DTE uses Maximo as the enterprise work and asset management platform. This  
25 project will focus on several key areas, including database health, to ensure data

Line  
No.

1 integrity and consistency across environments, to ensure Maximo's reliability,  
2 security, and efficiency in support of the Company's business operations. The  
3 project will upgrade to a supported software versioning system for better code  
4 traceability and protect privileged identities using an enterprise privilege access  
5 management solution. Benefits include improved data management efficiency and  
6 application performance, enhanced data integrity and consistency, faster  
7 deployments through automated testing, and reduced risk of unauthorized access to  
8 Maximo credentials. The project will permit DTE to continue to utilize Maximo by  
9 leveraging existing archiving solutions and implement necessary upgrades and  
10 security measures. See Exhibit A-24, Schedule N3 Line 80 for additional project  
11 details.

12  
13 12) Network Reliability and Monitoring

14 The Company is seeking recovery for \$1.7 million in the Network Reliability and  
15 Monitoring project over the 24 months ending December 31, 2025, and the  
16 historical spend of \$0.8 million in 2023, as shown on line 12 of Exhibit A-12,  
17 Schedule B5.7.4.

18  
19 Network Reliability and Monitoring is an annual investment that will continue in  
20 2025. Network monitoring provides real-time response capability to respond to and  
21 resolve performance or availability issues before the technology asset impacts  
22 business operations. This project is required to maintain tracking and monitoring  
23 tools to monitor, collect, and surface issues regarding application and infrastructure  
24 performance and involves fine tuning tools to reduce the required manual efforts to  
25 gain visibility on asset health.

Line  
No.

1 The Company reports a variance of \$1.7 million more in the 24 months ending  
2 December 31, 2024, than was approved for cost recovery in Case No. U-21534. Of  
3 this amount, \$0.2 million is due to the disallowances of 10% in 2023 and 20% in  
4 2024 directed by the Case No. U-21534 Final Order. The additional \$1.5 million is  
5 due to the additional scope identified during technical analysis due to which the  
6 project schedule must be extended into 2025. To manage the significant cost  
7 increase of phased implementation, the entire core infrastructures and monitoring  
8 solution were implemented during the initial phases. This approach was adopted to  
9 optimize results and reduce costs in the remaining phases. See Exhibit A-24,  
10 Schedule N3 Lines 81 to 83 for additional project details.

11

12 13) Nuclear Generation Business Systems Replacement

13 The Company is seeking recovery for \$1.7 million in the Nuclear Generation  
14 Business Systems Replacement project over the 36 months ending December 31,  
15 2026, and the historical spend of \$0.8 million in 2023, as shown on line 13 of  
16 Exhibit A-12, Schedule B5.7.4.

17

18 The Nuclear Generation Business Systems Replacement project will continue in  
19 2026. Nuclear Generation has 36 applications that require regular security  
20 vulnerability remediation. These applications require annual software, hardware,  
21 and database environment upgrades or replacement due to regulatory changes,  
22 obsolescence, security vulnerabilities, and continued protection from the risk of  
23 system failure and possible cyber attack. This project will refresh the server stack  
24 that supports the Nuclear Generation application environment with current long-  
25 term vendor supported systems that represent best security practices and increase

Line  
No.

1 system reliability while reducing security and system outage vulnerabilities. See  
2 Exhibit A-24, Schedule N3 Lines 84 to 87 for additional project details.

3

4 14) Production Growth

5 The Company is seeking recovery for \$4.2 million in the Production Growth project  
6 over the 36 months ending December 31, 2026, and the historical spend of \$1.7  
7 million in 2023, as shown on line 14 of Exhibit A-12, Schedule B5.7.4.

8

9 Production Growth is an annual investment that will continue in 2026. This project  
10 supports the annual growth resulting from the ongoing increase in data and business  
11 processing needs by providing Just-In-Time computing power, storage capacity,  
12 database availability, and middle-tier infrastructure. As technology products  
13 approach the end of the product lifecycle, the Company must continue to make  
14 investments to support those products to ensure that software and hardware is  
15 operational to run the business. This project also enables IT business operations to  
16 perform within prescribed CPU-capacity, storage thresholds, system response  
17 times, and availability.

18

19 The Company reports a variance of \$1.0 million more in the 36 months ending  
20 December 31, 2025, than was approved for cost recovery in Case No. U-21534. Of  
21 this amount, \$0.7 million is due to the disallowances of 10% in 2023 and 20% in  
22 2024 and 2025 directed by the Case No. U-21534 Final Order. The remaining \$0.3  
23 million is due to the additional scope for upgrading the Generation Management  
24 System from Red Hat Enterprise Linux (RHEL) version 7 to version 8. See Exhibit  
25 A-24, Schedule N3 Lines 88 to 91 for additional project details.

Line  
No.

1           15)     Renewable Operations Application Health

2           The Company is seeking recovery for \$0.4 million in the Renewable Operations  
3           Application Health project over the 36 months ending December 31, 2026, and the  
4           historical spend of \$0.1 million in 2023, as shown on line 15 of Exhibit A-12,  
5           Schedule B5.7.4.

6

7           The Renewable Energy Operations Application Health is an annual investment that  
8           will continue in 2026. The Renewable Energy Operations organization performs  
9           monitoring, operations, and maintenance of all Company-owned wind and solar  
10          assets. Renewable assets include IT infrastructure, applications, and systems for the  
11          existing ten wind facilities and seven solar parks. Operations include predictive  
12          analytics on turbine health data, case management, work scheduling, and work  
13          tracking. Key activities involve application upgrades, patching support, and  
14          maintaining asset health for telecommunications and data center infrastructure. See  
15          Exhibit A- 24, Schedule N3 Lines 92 to 95 for additional project details.

16

17          16)     Storm Resiliency

18          The Company is seeking recovery for \$7.9 million in the Storm Resiliency project  
19          over the 12 months ending December 31, 2026, as shown on line 17 of Exhibit A-  
20          12, Schedule B5.7.4.

21

22          The Storm Resiliency project aims to enhance the resilience and performance of  
23          critical systems to ensure operational continuity and robust support during storm  
24          events. This project focuses on the following key components: System Operations  
25          Suite (SOS) Hardening; Operational Support Applications (OSA) Hardening;

Line  
No.

1 Enterprise Service Bus (ESB) Hardening; and ChatBot Re-platforming. The SOS  
2 Hardening component will strengthen the SOS system to address vulnerabilities  
3 and optimize performance. The OSA Hardening component will reinforce the OSA  
4 system to handle increased loads and potential threats during storms. The Enterprise  
5 Service Bus (ESB) Hardening component will reinforce the ESB system to handle  
6 increased loads and potential threats during storms. The ChatBot Re-platforming  
7 component will upgrade the ChatBot platform to improve its capabilities in  
8 handling storm-related inquiries and tasks. See Exhibit A- 24, Schedule N3 Line 96  
9 for additional project details.

10

11 17) System for Fossil Generation for Coal and Gas

12 The Company is seeking recovery for \$2.1 million in the System for Fossil  
13 Generation for Coal and Gas project over the 36 months ending December 31, 2026,  
14 and has a historical spend of \$0.3 million in 2023, as shown on line 18 of Exhibit  
15 A-12, Schedule B5.7.4.

16

17 The System for Fossil Generation for Coal and Gas project will continue in 2026.  
18 The scope of this project is to implement the latest vendor releases and software  
19 patches for Fossil Generation's (FosGen's)/Energy Supply's application suite,  
20 which includes Akwire, Plantview, the Laboratory Management System (LMS),  
21 the Overtime Management System (OTM), and the Power Plant Management  
22 System (P3M). All of these applications require monthly releases and hardware and  
23 software upgrades in alignment with accommodating vendor releases. The project  
24 will update the Generating Availability Data System (GADS) reporting process as  
25 needed, especially to reduce manual workarounds and transition manual entry into

Line  
No.

1 automated or programmatic features. Data validity is essential on the GADS  
2 system, as it not only affects operations but is also reviewed by MISO and federal  
3 regulatory agencies including FERC. Therefore, failure to install required updates  
4 presents an unacceptably high risk of data inaccuracy.

5  
6 The Company reports a variance of \$0.9 million more in the 36 months ending  
7 December 31, 2025, than was approved for cost recovery in Case No. U-21534. Of  
8 this amount, \$0.2 million was due to the disallowances of 10% in 2023 and 20% in  
9 2024 and, 2025 directed by the Case No. U-21534 Final Order. The remaining \$0.7  
10 million is due the additional scope of the Primavera upgrade, which was out of  
11 support and unable to patch vulnerabilities. See Exhibit A-24, Schedule N3 Lines  
12 100 to 103 for additional project details.

13

14 18) System Outage Screen (SOS) Application Health

15 The Company is seeking recovery for \$1.3 million in the System Outage Screen  
16 (SOS) Application Health project over the 24 months ending December 31, 2026,  
17 as shown on line 19 of Exhibit A-12, Schedule B5.7.4.

18

19 The System Outage Screen (SOS) is a critical web-based application used by  
20 Distribution Operations to streamline and manage outage restoration activities.  
21 Widely utilized by Electrical Dispatch Operations and field teams, the SOS  
22 application supports day-to-day tasks and operational demands during both routine  
23 and emergency scenarios. It plays a pivotal role in ensuring efficient outage  
24 restoration and resource allocation, particularly for Overhead (OH) and  
25 Underground (UG) work, handled by Regional Control Operations (RCO) teams.



Line  
No.

1 The scope of the project is to Integrate Real-Time Data: Centralize outage updates  
2 and integrate with systems like Electrical Dispatch and Outage Dashboards for  
3 improved visibility. Automate Crew Assignments: Optimize resource allocation  
4 and reduce delays through automated, geographically efficient crew assignments.  
5 Additionally, this project also covers bug fixes, monitoring for the existing SOS  
6 application. See Exhibit A-24, Schedule N3 Lines 104, 105 for additional project  
7 details.

8

9 *b) Return-to-Health*

10 **Q78. What is the Plant & Field Portfolio investment in the Return-to-Health**  
11 **category?**

12 A78. The Company is seeking recovery for \$58.8 million in the Return-to-Health  
13 category of the Plant & Field Portfolio over the 36 months ending December 31,  
14 2026, and the historical spend of \$11.3 million over 12 months ending December  
15 31, 2023, as shown in lines 20 to 33 of the Capital Expenditures Exhibit A-12,  
16 Schedule B5.7.4. These investments are described below.

17

18 1) Advance Metering Infrastructure (AMI) Field Collection System

19 The Company is seeking recovery for \$4.2 million in the Advance Metering  
20 Infrastructure Field Collection System project (AMI) over the 24 months ending  
21 December 31, 2025, and the historical spend of \$5.5 million in 2023, as shown on  
22 line 20 of Exhibit A-12, Schedule B5.7.4.

23

24 The AMI Collection Engine (CE) requires updates to remain on vendor supported  
25 technology as well as operate within established security standards. The project will

Line  
No.

1 address this by upgrading AMI server operating systems and databases to the  
2 current required version and add system performance capability. Additional  
3 functionality will be added to the AMI system for daily interval readings, tracking  
4 disconnects and new reporting features.

5  
6 The Company reports a variance of \$5.8 million more in the 36 months ending  
7 December 31, 2024, than was approved for cost recovery in Case No. U-21534. Of  
8 this amount, \$0.8 million is due to the disallowances of 10% in 2023 and 20% in  
9 2024 and 2025 directed by the Case No. U-21534 Final Order. Additionally, \$2.8  
10 million was allocated for the acquisition of disaster recovery infrastructure. The  
11 remaining \$2.2 million increase is attributed to 16 additional servers that were  
12 purchased to create an active/active AMI application environment. These servers  
13 are required to install a virtual environment that reduces downtime to the AMI  
14 application. This enables continuous communication to the AMI electric meters  
15 and reduced downtime for managing customer meter accounts. See Exhibit A-24,  
16 Schedule N3 Lines 106-108 for additional project details.

17

18 2) Cable Routing Application (CRA) Replatform

19 The Company is seeking recovery for \$0.7 million in the Cable Routing  
20 Application (CRA) Replatform project (AMI) over the 12 months ending  
21 December 31, 2024, as shown on line 21 of Exhibit A-12, Schedule B5.7.4.

22

23 The Cable Routing Application (CRA) is an engineering design tool that provides  
24 information for construction to install raceway equipment and pull cables from  
25 point A to point B and is also used as a maintenance and operations tool for

Line  
No.

1 troubleshooting and repair. The scope of the project is to develop an in-house  
2 solution to replace the legacy CRA application.

3  
4 The Company reports a variance of \$0.2 million more in the 12 months ending  
5 December 31, 2024, than was approved for cost recovery in Case No. U-21534,  
6 primarily due to the 20% disallowance in 2024 directed by the Case No. U-21534  
7 Final Order. See Exhibit A-24, Schedule N3 Line 109 for additional project details.

8

9 3) Corporate Instance - Maximo Application Suite Upgrade Phase 1

10 The Company is seeking recovery for \$8.2 million in Corporate Instance - Maximo  
11 Application Suite Upgrade project over the 12 months ending December 31, 2026,  
12 as shown on line 22 of Exhibit A-12, Schedule B5.7.4.

13

14 The corporate instance of Maximo Suite supports the Work Asset Management  
15 function for several key business units at DTE, including Distribution Electric  
16 Operations work and asset management. This asset and platform are critical to serve  
17 the needs of the Company's customers and service the grid. The current version of  
18 Maximo 7 is scheduled to end vendor support in September of 2025. This project  
19 involves the planning and design for the new version of Maximo, which will  
20 support the future needs of the enterprise and ensure resiliency and agility to  
21 respond to future needs. This new platform is aligned with the latest technology  
22 and security standards and will provide DTE a supported work and asset  
23 management platform. The newer version of Maximo is more than just a traditional  
24 upgrade; it requires a complete re-platforming because the underlying hardware and  
25 technical architecture is new. The Company will complete the planning and design

Line  
No.

1 phases for the new platform and will focus on initial infrastructure build,  
2 development, testing, deployment, and hyper care.

3

4 The Company has reported a \$3 million variance due to the deferral of a project  
5 into 2026. Successful vendor negotiations have resulted in support being extended  
6 until 2026, thereby causing project deferral See Exhibit A-24, Schedule N3 Line  
7 110 for additional project details.

8

9 4) DTE Utility Network (UN) Model – Full Implementation

10 The Company is seeking recovery for \$5.2 million in the DTE Utility Network  
11 (UN) Model project over the 12 months ending December 31, 2026, as shown on  
12 line 23 of Exhibit A-12, Schedule B5.7.4.

13

14 The DTE Utility Network (UN) Model project will continue in 2026. DTE currently  
15 uses the ESRI ArcMap platform GIS (Geographic Information System) for  
16 geospatial data and analysis. This data includes information such as the distribution  
17 of electrical assets. ArcMap, however, will no longer be supported by 2026. To  
18 account for this adjustment and maintain the Company's current-state capabilities,  
19 the DTE Electric Utility Network project will implement the new ESRI UN product  
20 in the cloud. This product replacement will increase availability, recoverability,  
21 scalability, and security while enabling business process efficiency. The initiative  
22 will leverage the latest technology on location data, business intelligence, and  
23 integrated systems to drive enterprise system automation and business performance  
24 for the Company's public-facing and internal IT systems. It will improve safety in

Line  
No.

1 the field, improve reliability metrics and outage information, and reduce customer  
2 complaints, and improve overall customer satisfaction.

3  
4 The Company reflects a variance of \$0.6 million less in the 24 months ending  
5 December 31, 2024, than was approved for cost recovery in Case No. U-21534 due  
6 to project schedule deferral to 2026. The Company successfully negotiated  
7 extended support for the ESRI ArcMap platform GIS until 2026. See Exhibit A-24,  
8 Schedule N3 Line 111 for additional project details.

9  
10 5) EOL - Linux Return to Health

11 The Company is seeking recovery for \$0.3 million in End Of Life (EOL) – Linux  
12 Return to Health project over the 12 months ending December 31, 2025, as shown  
13 on line 24 of Exhibit A-12, Schedule B5.7.4.

14  
15 The EOL - Linux Return to Health project addresses critical risks associated with  
16 end-of-life servers and outdated Linux operating systems within the Information  
17 Technology System (ITS) Generation department. This project will replace  
18 outdated servers and upgrade operating systems to ensure system stability, security,  
19 and compliance. ITS Generation currently supports a number of applications  
20 critical for Energy Supply and operations. However, six (6) servers are reaching  
21 their end of life, and twenty-two (22) are running on an end-of-life Linux operating  
22 system and reliance on extended support for these outdated assets is not a  
23 sustainable solution. This situation poses significant risks to the stability and  
24 security of the systems supporting Energy Supply by increasing their vulnerability  
25 to cyber threats, potential system failures, and non-compliance. The benefits of this

Line  
No.

1 investment in replacement of out-of-date servers and upgrading operating systems  
2 are enhanced cybersecurity measures, improved system stability, and compatibility  
3 with the latest industry standards. See Exhibit A-24, Schedule N3 Line 112 for  
4 additional project details.

5

6 6) eSOMS CORA Access Integration

7 The Company is seeking recovery for \$0.3 million in Electronic Shift Operations  
8 Management (eSOMS) Control Room Automation (CORA) Access Integration  
9 project over the 12 months ending December 31, 2025, as shown on line 25 of  
10 Exhibit A-12, Schedule B5.7.4.

11

12 This project will integrate currently unsupported CORA and MS Access point logs  
13 that Nuclear Generation uses for 10 C.F.R. § 50 Appendix B compliance into the  
14 existing eSOMS Narrative Log Module, which supports all aspects of Shift  
15 Operations Management and was implemented at Fermi2 in 2019. The following  
16 logs, which were not captured in the 2019 implementation due to budget and time  
17 constraints, will be integrated: Radwaste Logs, Oil Log, Fire Impairment Log,  
18 Jumper Log, Condensate Filter Demineralizer Log, Temp Power Log, Confined  
19 Space Log, and FME Log. This integration will enhance security, reliability, and  
20 operational visibility and reduce administrative and training burdens. See Exhibit  
21 A-24, Schedule N3 Line 113 for additional project details.

22

23 7) Field Service Edge (FSE) Replacement – ClickSoft

Line  
No.

1 The Company is seeking recovery for \$23.0 million in the Field Service Edge (FSE)  
2 Replacement – ClickSoft project over the 24 months ending December 31, 2026,  
3 as shown on line 26 of Exhibit A-12, Schedule B5.7.4.

4  
5 DTE’s Substation, Electric Field Operations (EFO) & Power Equipment and Relay  
6 Testing (PERT), Revenue Management and Protection (RMP), Meter Reading, and  
7 Overhead and Underground (OH/UG) business units use the Field Service Edge  
8 (FSE) - ClickSoft application for dispatching and scheduling work to manage their  
9 daily operations. Field Service Edge (FSE) - ClickSoft is a cloud-based application  
10 that provides dispatchers with crew visibility, real-time status updates at the point  
11 of activity for customers, and insight into business and crew requests. Salesforce  
12 has announced that Click Field Service Edge will be retired by Q4 2026 and no  
13 longer available for use. This investment will migrate the following functionalities  
14 to a fully supported field service management system: Crew Management,  
15 Scheduling & Route Optimization, Appointment Management, Configuration &  
16 Workflow Management, Document Management & Attachments,  
17 Asset/Location/Crew Mapping, Field Work Management, Messaging &  
18 Communication, Time Management, and Performance Management & Reporting.  
19 See Exhibit A-24, Schedule N3 Lines 114, 115 for additional project details.

20

21 8) Fuel Supply-Plant Fuel Management System

22 The Company is seeking recovery for \$2.9 million in the Fuel Supply-Plant Fuel  
23 Management System project over the 24 months ending December 31, 2025, as  
24 shown on line 27 of Exhibit A-12, Schedule B5.7.4.

Line  
No.

1 The current solution for fuel management is on a legacy application platform  
2 nearing the end of its lifecycle. The project scope is to replace the Automatic Rail  
3 Receipt (ARR) application functions that currently use the Oracle Forms platform  
4 with a supported web-based platform utilized by other DTE applications. As the  
5 current system is 20 years old, the user interface will be streamlined in alignment  
6 with current business processes utilizing modern user experience standards,  
7 functioning on a current and supported development platform.

8

9 The Company reports a variance of \$1.5 million more in the 12 months ending  
10 December 31, 2024, than was approved for cost recovery in Case No. U-21534. Of  
11 this amount, \$0.4 million is due to the 20% disallowance directed by the Case No.  
12 U-21534 Final Order and the remaining \$1.1 million is due to increased vendor  
13 costs due to the complexity of the code during re-platforming of Fuel Supply's ARR  
14 application to Oracle APEX platform. This delayed the project in 2024; scope and  
15 schedule were extended to 2025. See Exhibit A-24, Schedule N3 Lines 116, 117  
16 for additional project details.

17

18 9) Maximo Platform Program

19 The Company is seeking recovery for \$10.6 million in the Maximo Platform  
20 Program project over the 24 months ending December 31, 2025, and the historical  
21 spend of \$2.9 million in 2023, as shown on line 28 of Exhibit A-12, Schedule  
22 B5.7.4.

23

24 The Maximo system (version 7.6.0), which provides functionalities including  
25 procurement of assets, preventative maintenance of assets, install and replacements



Line  
No.

1 of assets, work order management, timekeeping, and materials management, was  
2 initially implemented in 2015. This project will implement configuration changes,  
3 new feature enhancements, mobile enablement, and automated business processes  
4 for Work and Asset Management through the vendor, IBM.

5  
6 The Company reports a variance of \$9.5 million more in the 36 months ending  
7 December 31, 2025, than was approved for cost recovery in Case No. U-21534. Of  
8 this amount, \$0.7 million is attributed to the disallowances of 10% in 2023 and 20%  
9 in 2024 and 2025, as directed by the Case No. U-21534 Final Order. The remaining  
10 \$8.8 million is due to additional licenses that were acquired as a result of the true-  
11 up process of Maximo licenses under the Company's IBM contract. See Exhibit A-  
12 24, Schedule N3 Lines 118 - 120 for additional project details.

13

14 10) P3M Heat Rate Calculation and GADS Reporting Functions

15 The Company is seeking recovery for \$0.9 million in the Power Plant Performance  
16 Management (P3M) Heat Rate Calculation and Generating Availability Data  
17 System (GADS) Reporting Functions project over the 12 months ending December  
18 31, 2023, as shown on line 30 of Exhibit A-12, Schedule B5.7.4.

19

20 The scope of the project was to replace the Oracle Forms platform with a java J2EE  
21 web-based platform utilized by other DTE applications. As the current system was  
22 20 years old, the user interface was streamlined in alignment with current business  
23 processes utilizing modern user experience standards.

Line  
No.

1 The Company reports a variance of \$0.2 million more in the 12 months ending  
2 December 31, 2023, than was approved for the cost recovery in Case No. U-21534,  
3 due to the disallowance of 10% in 2023 as directed by the Case No. U-21534 Final  
4 Order. See Exhibit A-24, Schedule N3 Lines 122, 123 for additional project details.

5  
6 11) Vegetation management re-platform (Clearion Replacement)

7 The Company is seeking recovery for \$3.4 million in the Vegetation Management  
8 re-platform (Clearion Replacement) project over the 12 months ending December  
9 31, 2026, as shown on line 33 of Exhibit A-12, Schedule B5.7.4.

10

11 The current vegetation management software (Clearion) that was implemented in  
12 2016 is reaching end of life support in March of 2026. The current solution lacks  
13 quality vendor support, is experiencing data management and scalability issues, and  
14 operates on legacy technology within an on-premises implementation. To avoid  
15 loss of data visibility, analytical reporting, loss of ESRI support, and work  
16 stoppages, Clearion will be replaced with a viable SaaS solution before the end-of-  
17 life deadline. See Exhibit A-24, Schedule N3 Line 126 for additional project details.

18

19 *c) IT Enhancements*

20 **Q79. What is the Plant & Field Portfolio investment in the IT Enhancements**  
21 **category?**

22 A79. The Company is seeking recovery for \$3.1 million in the IT Enhancements category  
23 of the Plant & Field Portfolio over the 12 months ending December 31, 2026, as  
24 shown in line 34 of the Capital Expenditures Exhibit A-12, Schedule B5.7.4. This  
25 investment is described below.

Line  
No.

1) Corporate Instance - Enterprise Maximo Transformation

The Company is seeking recovery for \$3.1 million in the Corporate Instance – Enterprise Maximo Transformation Project over the 12 months ending December 31, 2026, as shown on line 34 of Exhibit A-12, Schedule B5.7.4.

The Corporate Maximo system supports business units including Electric Distribution Operations, Gas Operations, Energy Supply, Supply Chain, Fleet, Facilities, and DTE Vantage. Challenges facing the current system include limited document attachment functionality, a cumbersome spare parts upload process, one-way communication between SAP and Maximo, increased costs due to customization of bolt-ons, system downtime during updates, and slow system performance and reporting database issues. Transformation (upgrade) of the Corporate Enterprise Maximo system is required to improve efficiency and effectiveness and address these challenges. The upgraded system's proposed functionalities include real-time construction scheduling, scheduling for both planned and unplanned work, the ability to assign and update multiple work orders, and geo-spatial capability to track crew locations. This project will utilize built-in document attachment features, increase the use of mobile devices for field data input and retrieval, enhance employee engagement with AMFC and Maximo, establish strong reporting capabilities, accurately track spare parts, inventory, and costs, improve scheduling and dispatch tools, implement digital logbooks and permitting, and modify digital forms for consistent data capture. See Exhibit A-24, Schedule N3 Line 127 for additional project details.

Line  
No.

1 *d) Strategic*

2 **Q80. What is the Plant & Field Portfolio investment in the Strategic category?**

3 A80. The Company is seeking recovery for \$18.1 million in the Strategic category of the  
4 Plant & Field Portfolio over the 36 months ending December 31, 2026, and the  
5 historical spend of \$6.3 million over the 12 months ending December 31, 2023, as  
6 shown in lines 35 through 40 of the Capital Expenditures - Exhibit A-12, Schedule  
7 B5.7.4. These investments are described below.

8

9 1) Generation Optimization Status Tracker (GOST)

10 The Company is seeking recovery for \$1.2 million in the Generation Optimization  
11 Status Tracker (GOST) project over the 12 months ending December 31, 2025, as  
12 shown on line 36 of Exhibit A-12, Schedule B5.7.4.

13

14 Generation Optimization (Gen Ops) requires a technical solution that can help  
15 leverage business intelligence that allows DTE employees to access, analyze and  
16 visualize data from any Gen Ops IT-related system in real time, enabling users to  
17 create custom reports and data analytics that suits the Company's business market  
18 integration needs and goals. The GOST (Generation Optimization Status Tracker)  
19 will establish a self service platform that will allow Gen Ops to increase efficiency  
20 of the processes and will create a foundation for automation of many tasks Gen Ops  
21 executes: reporting, analytics, validations (i.e., meter data, profit and loss, market  
22 penalties, etc.). This will ensure Gen Ops remains in compliance with state and  
23 federal regulations (by FERC, NERC, MISO, MPSC) and quickly evolving  
24 business rules and industry demands. See Exhibit A-24, Schedule N3 Line 129 for  
25 additional project details.

Line  
No.

1           2)       Maximo Engineering Process Automation

2           The Company is seeking recovery for \$4.9 million in the Maximo Engineering  
3           Process Automation project over the 12 months ending December 31, 2024, and  
4           the historical spend of \$5.4 million over the 12 months ending December 31, 2023,  
5           as shown on line 37 of Exhibit A-12, Schedule B5.7.4.

6

7           The scope of this project is to streamline engineering and work management  
8           systems at Fermi and reduce manual tasks, improve reporting capabilities, and  
9           reduce technical complexity of managing multiple system interfaces. This project  
10          will establish the foundation for Electronic Work Packages to be enabled.

11

12          The Company reports a variance of \$4.2 million more in the 24 months ending  
13          December 31, 2024, than was approved for cost recovery in Case No. U-21534. Of  
14          this amount, \$1.1 million is due to the disallowances of 10% in 2023 and 20% in  
15          2024 directed by the Case No. U-21534 Final Order. The remaining variance  
16          amount of \$3.1 million is due to a combination of additional scope of the Integrated  
17          Information Resource (I2R) Replacement added to this project and cost  
18          reallocation. Note that in Case No. U-21534, the Maximo Engineering Process  
19          Automation originally scheduled for 2024 and 2025 was revised to 2023 and 2024.  
20          This shift was aimed not only at expediting project delivery but also at achieving  
21          cost savings. The \$3.1 million variance reflects the reallocated costs moved from  
22          2025. This reallocation underscores a strategic financial adjustment aimed at  
23          optimizing resource utilization and minimizing expenditure over the project's  
24          lifecycle. See Exhibit A-24, Schedule N3 Lines 130, 131 for additional project  
25          details.

Line  
No.

1           3)       Storm Data Lakehouse

2           The Company is seeking recovery for \$2.0 million in the Storm Data Lakehouse  
3           project over the 12 months ending December 31, 2026, as shown on line 39 of  
4           Exhibit A-12, Schedule B5.7.4.

5  
6           Situational awareness is paramount during storms that impact the Company's  
7           service territory and result in customer outages. DTE emergency headquarters and  
8           storm roles need timely and reliable access to Customer, Storm, job, and damage  
9           assessment information to effectively manage crew resources and provide  
10          customers with accurate restoration information. The Storm Data Lakehouse will  
11          build upon current enterprise data lake infrastructure to provide a performant,  
12          unified access layer for storm data and storm analytics needs. Currently the  
13          Company utilizes four separate databases in Azure to support the user load  
14          requirements; by implementing the Storm Data Lakehouse, the Company can  
15          reduce the number of databases and achieve cost optimization of cloud hosted  
16          database charges. These benefits of this investment will provide timely and reliable  
17          data for outages, regions, and customers impacted, which will enable improved  
18          decision making for storm restoration and enable better estimates for customers.  
19          This project supports the Company's storm response investments discussed in  
20          Company Witness Hill's testimony and the customer interaction improvements as  
21          discussed in Section VI.D.4.c of my testimony.

22  
23          The Company reports a variance of \$1.6 million more in the 12 months ending  
24          December 31, 2025, than was approved in Case No. U-21534 due to project

Line  
No.

1 reprioritization that caused a deferral to 2026. See Exhibit A-24, Schedule N3 Line  
2 134 for additional project details.

3

4 4) Storm Simulation Lab

5 The Company is seeking recovery for \$10.0 million in the Storm Simulation Lab  
6 project over the 36 months ending December 31, 2026, as shown on line 40 of  
7 Exhibit A-12, Schedule B5.7.4.

8

9 From 2021 through 2023, DTE Electric experienced 13 severe weather-related  
10 events, each exceeding 110,000 unique customer outages, averaging 274,000  
11 customers impacted. These significant outages, called “Catastrophic” or “CAT  
12 Storms,” impacted the Company’s IT systems 60% of the time. The average  
13 duration of these IT-related outages was 6.8 hours. During CAT Storms, customers  
14 might have been unable to report outages or hazards and received delayed or  
15 incorrect restoration updates. Field crews had to rely on manual processes for  
16 planning, scheduling, dispatching, and status updates, reducing their efficiency.  
17 Analyzing the data from these IT major incidents shows that, during 60% of those  
18 events, these kinds of system failures are directly caused by high load that is beyond  
19 the design capacity of the related and interconnected systems. While the Company  
20 has remediated these issues and corrected the system designs in reaction to these  
21 storm events, DTE Electric has no ability to identify these failure points before they  
22 impact customers and employees. The Storm Simulation Lab project will test and  
23 enhance the resilience of DTE Electric’s storm-critical IT systems, reducing load-  
24 related outages by a projected 10% during CAT Storms. By simulating storm  
25 conditions, the lab will help identify and address system weaknesses before they

Line  
No.

1 impact customers. This initiative supports DTE Electric's goals of ensuring grid  
2 reliability, timely restoration, and minimizing outage durations. This project  
3 supports the Company's storm response investments discussed in Company  
4 Witness Hill's testimony and the customer interaction improvements as discussed  
5 in Section VI.D.4.c of my testimony. See Exhibit A-24 Schedule N3 Lines 135 -  
6 137 for additional project details.

7

8 **D. Customer IT**

9 **Q81. What are the projected costs for investments in the Customer IT Portfolio?**

10 A81. As reflected on line 3 of Exhibit A-12, Schedule B5.7, page 1, capital costs for the  
11 investments in the Customer IT Portfolio total \$70.2 million for the historical period  
12 year ending December 31, 2023, \$110.8 million in the bridge period (for the 24  
13 months ending December 31, 2025), and \$64.7 million for the projected test period  
14 ending December 31, 2026.

15

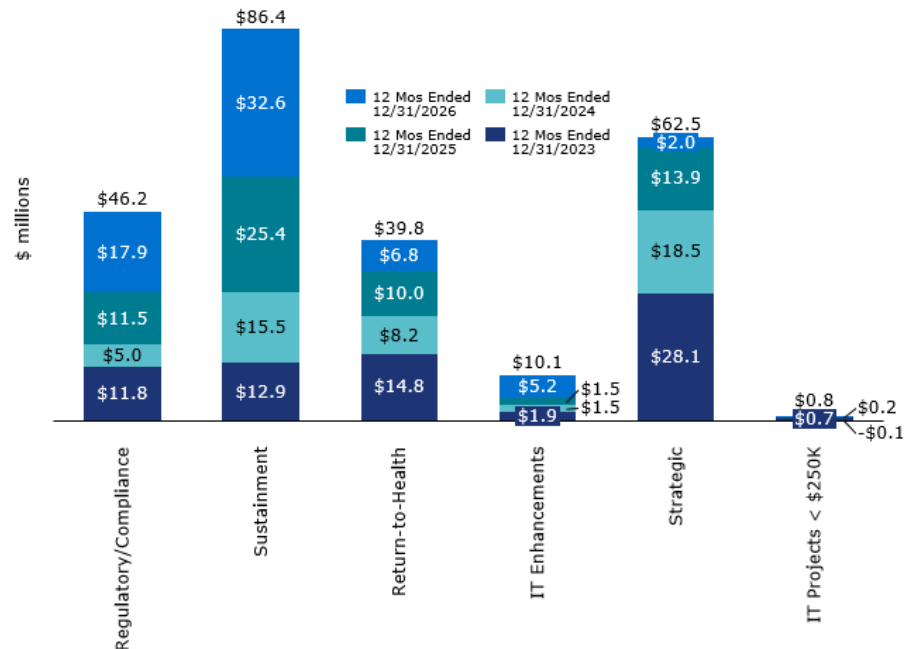
16 The synopses below provide the total spend for each line item the Company requests  
17 in this rate case. The cost details for projects in the Customer IT Portfolio broken out  
18 by historical period, projected bridge period, and projected test period are provided in  
19 Exhibit A-12, Schedule B5.7.2, in columns (d), (g) and (h), respectively. Figure 12  
20 below represents a high-level view of capital allocations within the Portfolio.



Line  
No.

1

Figure 12 Customer IT Investment



2

3 **Q82. Does your testimony address all of the Customer IT Portfolio projects?**

4 A82. Yes. In Case No. U-21534, these projects were split between Company Witnesses  
 5 Sharma and Hatsios. In the instant case, the Company has included all Customer  
 6 IT Portfolio projects in my testimony for clarity and ease of reference.

7

8 *1. Regulatory/Compliance*

9 **Q83. Please explain the Customer IT Portfolio investments in the Regulatory /**  
 10 **Compliance category.**

11 A83. The Company will invest \$11.8 million in 2023 historical, \$16.5 million in 2024-  
 12 2025 bridge, and \$17.9 million in 2026 test period capital in  
 13 Regulatory/Compliance non-discretionary projects that must satisfy MPSC

Line  
No.

1 requirements and rate orders, and other industry regulations and compliance items  
2 that are necessary to serve customers. In this part of my testimony, I will explain  
3 in detail the Company's non-discretionary investments in the Regulatory /  
4 Compliance investment category of the Customer IT Portfolio, which are shown in  
5 lines 1 through 10 of Exhibit A-12, Schedule B5.7.2. Specifically, I will discuss  
6 the following eight of the Company's ten Regulatory / Compliance projects in my  
7 direct testimony, excluding the Time of Day and PCI projects that were approved  
8 for recovery in Case No. U-21534 (see Table 1 above).

9  
10 (1) Customer Consent and Preference Management

11 The Company is investing \$1.8 million in 2026 test period capital, as shown on line  
12 1 in Exhibit A-12, Schedule B5.7.2, to implement an enhanced and robust customer  
13 consent and preference management solution that is integrated across all  
14 communications platforms. This project aims to centralize and streamline the way  
15 customer consents and preferences are managed for various communications (i.e.,  
16 phone, text, email, and other technologies), to support compliance with regulatory  
17 requirements while keeping customers informed about the status of their order or  
18 sending other beneficial customer communications and enhancing their overall  
19 customer experience.

20 The primary driver for this project is the Federal Communications Commission's  
21 (FCC) recently amended rules under the Telephone Consumer Protection Act  
22 (TCPA). The FCC's amended rules under the TCPA require, among other things,  
23 that:

- 24 • Individuals can revoke consent for auto-dialed or pre-recorded/artificial voice  
25 calls and texts at any time, through any reasonable means.

Line  
No.

- 1 • Texting consent specifically can be revoked via: Stop, Quit, End, Revoke, Opt
- 2 Out, Cancel, or Unsubscribe
- 3 • Any reasonably similar words must also be treated as revocable.
- 4 • The deadline to honor revocable request is 10 business days.
- 5 • If reply texts are not feasible, then the text must clearly disclose to recipient that
- 6 two-way texting is not available for technical reasons and provide an alternative
- 7 means for revocation.

8

9 By implementing a preference center solution, customers will be able to more  
10 pointedly indicate what types of communications they want to receive and through  
11 what channels. In turn, the Company will be able to send communications  
12 according to a customer's indicated preferences and thereby support compliance  
13 regarding how it communicates with customers (i.e., opt-ins, opt-outs, and more).  
14 The solution will also be integrated seamlessly with the Company's existing  
15 systems, ensuring that customer data and preferences are consistently updated,  
16 accessible and readily utilized by all relevant departments that communicate  
17 directly with customers. See Exhibit A-24, Schedule N3 Line 382 for additional  
18 project details.

19

20 (2) Regulatory Compliance

21 The Company is investing \$2.9 million in the projected 2026 test period capital for  
22 the Regulatory Compliance project to fund ongoing and emerging rate changes  
23 required to be implemented in the CR&B system. The 2023-2025 spend of 2.1  
24 million in the 2023 historical period and \$6.5 million in the 2024-2025 bridge  
25 period, as shown on line 8 of Exhibit A-12, Schedule B5.7.2, was approved for cost

Line  
No.

1 recovery in Case No. U-21534. See Exhibit A-24, Schedule N3 Line 398 for  
2 additional project details.

3  
4 This project funds CR&B and reporting system changes necessary to comply with  
5 the outcome of any MPSC rate orders, to provide funding for emerging regulatory  
6 compliance items, and to fund the implementation of new rates and programs as  
7 approved by the MPSC.

8  
9 In Case No. U-21534, the Commission approved the transition of D1.6 customers  
10 to D1.11, the expansion of LIA credit availability to all residential base rates, and  
11 the direction to implement the D3.11 Commercial Time-of-Use (TOU) and D14  
12 Primary TOU rates. The transition to TOU rates provides an opportunity not only  
13 to re-align rate design for D1.6 customers, but also to expand their ability to choose  
14 their base rate schedule while retaining the LIA credit. The new D3.11 and D14  
15 TOU rates similarly provide additional optionality. The transition and  
16 implementation of the rates will occur during the projected bridge year as directed  
17 by the Commission. Thus, the Company's Exhibit A-16, Schedules F3 and F8 will  
18 reflect the elimination of D1.6 into the 2026 projected test year, the transition of  
19 those customers to D1.11, and the addition of the D3.11 and D14 rates given the  
20 Commission's approval in Case No. U-21534.

21  
22 In addition to the scope previously described, this project continues to ensure there  
23 is sufficient funding for planned and emergent revisions to electric rates,  
24 amendments to rate schedules and rules governing the distribution and supply of

Line  
No.

1 electric energy, and any other modifications of DTE Electric rates in accordance  
2 with MPSC orders.

3

4 **Q84. What are the Company's investments in the six MIGreenPower (MIGP)**  
5 **Regulatory / Compliance projects?**

6 A84. The Company is investing a total of \$24.4 million, consisting of \$1.5 million in the  
7 historical 12 months ending December 31, 2023, \$9.7 million in the 2024-2025  
8 bridge period, and \$13.3 million in the 2026 test period capital as shown in Exhibit  
9 A-12 Schedule B5.7.2, in the expansion and creation of products and services that  
10 allow customers to contribute to a cleaner environment. These investments satisfy  
11 the Company's commitments to the MPSC and customers under DTE Electric's  
12 renewable energy plan (REP) and voluntary green pricing (VGP) cases originally  
13 approved in Case Nos. U-20851 and U-20713.

14

15 Each of the MIGP tariffs have been approved by the MPSC for implementation,  
16 with the associated capital dollars reflecting the investment necessary to build the  
17 required fixed or volumetric charges in the CR&B system, enroll or reserve  
18 customer interest in a specific MIGP program, update the Company's MIGP  
19 Website, or create supporting internal dashboarding and reporting to enable  
20 efficient management of the MIGP programs.

21

22 (3) MIGP Customer – Requested Renewable Energy Projects

23 This project was previously approved for recovery of a \$8.2 million in 2023-2024  
24 bridge period (\$2.7 million) and 2025 test period (\$5.5 million) capital in the Case  
25 No. U-21534 Final Order and supports the scope of work previously described in

Line  
No.

1 Company Witness Hatsios' direct testimony in that case. Construction delays have  
2 resulted in a deferral of project implementation into 2026, and as such, the  
3 Company spent very little capital in 2023-2024 (as reflected in U-21860, Exhibit  
4 A-12, Schedule B5.7.2, Line 2) but continues to forecast spend of \$5.5 million in  
5 2025 and \$3.0 million in the 2026 test year period of the instant case. See Exhibit  
6 A-24, Schedule N3 line 386 for additional project details.

7

8 (4) MIGP Large Customer Pre-Payment

9 The MIGP Large Customer Pre-Payment project was previously approved for  
10 recovery of \$1.3 million in the 2025 test year capital in the Case No. U-21534 Final  
11 Order. Due to budget constraints, the project was deferred to the 2026 test year  
12 with a spend of \$1.4 million as shown on line 3 of Exhibit A-12, Schedule B5.7.2.

13

14 The project will allow contracted customers the ability to prepay for future  
15 renewable energy charges per the Partial Settlement Agreement in Case No. U-  
16 21172 approved by the Commission on April 25, 2024. Development will include  
17 creating a separate renewable energy accounts receivable section on the customer's  
18 bill, a new accounting and general ledger system, and data and reporting tools to  
19 enable the program. See Exhibit A-24, Schedule N3 line 387 for additional project  
20 details.

21

22 (5) MIGP Low Income Solar Pilot

23 The MIGP Low Income Solar Pilot project was previously approved for recovery  
24 of \$1.2 million in the 2024 bridge project year and \$0.8 million in the 2025 test  
25 year in the Case No. U-21534 Final Order. The project has been delayed, and the

Line  
No.

1 Company is forecasting to spend the \$2.0 million in the 2026 test year period in  
2 this instant case as shown on line 4 of Exhibit A-12, Schedule B5.7.2. The Pilot  
3 program is taking longer than expected to launch due to a lack of funding for the  
4 Pilot projects. Because of the delay, the Company is not ready to enroll and bill  
5 customers for this Pilot program. See Exhibit A-24, Schedule N3 line 388 for  
6 additional project details.

7

8 (6) MIGP Reservation System for New Enrollments

9 This project was previously approved for recovery of \$1.5 million in capital in the  
10 Case No. U-21534 Final Order. The Company actually spent \$0.7 million in 2023  
11 historical year capital and \$0.1 million in 2024 bridge year capital on the MIGP  
12 Reservation Systems project as shown on Line 5 in Exhibit A-12, Schedule B5.7.2.  
13 The capital requested for this project reflects a variance of \$0.7 million less than  
14 was approved in Case No. U-21534. The variance is due to actuals not aligning  
15 with the forecast. See Exhibit A-24, Schedule N3 line 389 for additional project  
16 details.

17

18 (7) MIGP Scope 3 Billing and Enrollment

19 The Company is investing \$3.9 million in the 2026 test period capital in the MIGP  
20 Scope 3 Billing and Enrollment project, as shown on line 6 of Exhibit A-12,  
21 Schedule B5.7.2 to allow for sponsored MIGP enrollment per the Section 61  
22 agreement. Through this project, customers will have the ability to incur the  
23 renewable energy charges of another customer. For example, a business could elect  
24 to be billed for the renewable energy charges of its employees that enroll in the  
25 MIGP program. Similar in scope to many of the MIGP renewable projects, this

Line  
No.

1 project will include end-to-end enhancements to the CR&B system that will include  
2 the required billing, accounting, and reporting functionality. See Exhibit A-24,  
3 Schedule N3 line 391 for additional project details.

4  
5 (8) Rider 17 – MIGreenPower, Residential and Small Commercial & Industrial  
6 The Commission approved for recovery a total of \$4.9 million in 2023-2024 bridge  
7 period (\$1.9 million) and 2025 test period (\$3.0 million) capital in the Case No. U-  
8 21534 Final Order. In the instant case, the Company is requesting recovery of an  
9 additional \$3.0 million in 2026 test period capital to fulfill the Rider 17  
10 requirements, which includes the development and deployment of potential  
11 enrollment, billing and reporting requirements.

12  
13 This project replaces the Rider 19 MIGP Large Commercial & Industrial project,  
14 as Rider 19 ended on August 19, 2022, and has been merged with Rider 17. The  
15 project scope includes CR&B system changes required to create a fixed price  
16 offering for large customers and the ability to enroll residential and streetlighting  
17 accounts, bill customers, and other enhancements to manage and administer the  
18 program. See Exhibit A-24, Schedule N3 line 402 for additional project details.

19

20 **Q85. Are there any other projects included in your testimony that align with the**  
21 **MIGP Regulatory/Compliance projects?**

22 A85. Yes, there is one MIGP Strategic project and one MIGP Sustainment project that is  
23 related and supports these MIGP Regulatory / Compliance projects. Details  
24 regarding the two projects are discussed below.



Line  
No.

1 (9) MIGP Data and Reporting – Strategic category

2 This project was previously approved for recovery by the Commission for \$1.0  
3 million in 2023 capital in Case No. U-21534. The Company actually invested \$0.7  
4 million in 2023 and an additional \$1.0 million in 2024, as shown on line 51 of  
5 Exhibit A-12, Schedule B5.7.2. This project enhances the management of the  
6 MIGP programs and integrate the MIGP programs with other related products and  
7 services into one reporting solution.

8

9 The combined 2023-2024 scope allows the Company to efficiently track and  
10 manage MIGP enrollments, billing data, generation data and revenue. The new  
11 dashboarding platform replaced the manual process of running and exporting  
12 reports, analyzing the results, and then importing files to view in a dashboard,  
13 which has become unsustainable as the number of MIGP enrollments and programs  
14 continues to grow. Additionally, the upward trend in the volume of data points  
15 being processed is contributing to further slowdowns in manual processing time.  
16 The new dashboard provides timely and accurate data to manage enrollments,  
17 generation, and billing efficiently. See Exhibit A-24, Schedule N3 line 422 for  
18 additional project details.

19

20 *2. Sustainment*

21 **Q86. Please explain the Customer IT Portfolio investments in the Sustainment**  
22 **category.**

23 A86. The Company will invest \$73.5 million in the Sustainment category of the  
24 Customer IT Portfolio over the 36 months ending December 31, 2026, and a  
25 historical spend of \$12.9 million over the 12 months ending December 31, 2023,

Line  
No.

1 as shown in lines 11 through 28 of the Capital Expenditures Exhibit A-12, Schedule  
2 B5.7.2. These investments are described below.

3

4 1) Business Planning and Development (BPD) and Electric Sales & Marketing  
5 (ESM) Application Health

6 The Company is seeking recovery for \$2.2 million in the Business Planning and  
7 Development (BPD) and Electric Sales & Marketing (ESM) Application Health  
8 project over the 36 months ending December 31, 2026, and the historical spend of  
9 \$0.9 million over the 12 months ending December 31, 2023, as shown on line 11  
10 of Exhibit A-12, Schedule B5.7.2.

11

12 The BPD and ESM Application Health project will continue in 2026. This project  
13 represents the annual refresh of 12 IT assets that support the operations of Corporate  
14 Energy Forecasting, Integrated Resource Planning, Demand Response, Community  
15 Lighting, Joint Use, and Customer Choice. These departments and their associated  
16 applications support the Company's ability to effectively forecast system load for  
17 planning purposes and provide customers with alternative rates and products that  
18 assist them with managing their energy usage. This project provides the resources  
19 and services to complete required application software upgrades and hardware  
20 replacements, the development, testing and deployment of enhancements to  
21 improve functionality and performance required by business process changes, and  
22 end of life replacement of legacy operating systems, hardware, and cloud based  
23 virtual systems. This project scope also includes planning for mitigation of security  
24 vulnerabilities as required the Company's security policies. See Exhibit A-24,  
25 Schedule N3 Lines 315 - 318 for additional project details.

Line  
No.

1           2)       Contact Center Application Health

2           The Company is seeking recovery for \$3.4 million in the Contact Center  
3           Application Health project over the 36 months ending December 31, 2026, and the  
4           historical spend of \$1.1 million in 2023 as shown on line 12 of Exhibit A-12,  
5           Schedule B5.7.2.

6  
7           The Contact Center Application Health project will continue in 2026. The scope of  
8           the project is to continue investing in upgrades and security vulnerability  
9           remediation required to keep the Contact Center telephony and Integrated Voice  
10          Response (IVR) systems up and running. This work can include required software  
11          and hardware upgrades, modifying code or configuration as required to address  
12          significant issues or outages. These systems include applications, servers, and  
13          databases from vendor partners, Verizon, Avaya, and Swampfox, as well as some  
14          in-house DTE systems. Production release activities are often done in partnership  
15          with the supporting vendor. Annually there are 12 monthly builds and deployments  
16          to manage enhancements and upgrades. This requires services to build, test and  
17          deploy into production. See Exhibit A-24, Schedule N3 Lines 319 - 322 for  
18          additional project details.

19

20          3)       Cloud Platform Enterprise Agreement

21          The Company is seeking recovery for \$0.8 million in the Cloud Platform Enterprise  
22          Agreement project over the 12 months ending December 31, 2024, as shown on  
23          line 13 of Exhibit A-12, Schedule B5.7.2.

Line  
No.

1 This project covers a three-year capital cost for the Cloud Platform Enterprise  
2 Agreement (CPEA), which is a business model that allows for the consumption of  
3 cloud credits based on actual usage. This investment covers implementation support  
4 for hardware and environment upgrades, security vulnerability remediation, and the  
5 adoption of both major and minor software releases. Also included in this effort is  
6 the support for the user base as they respond to new business needs, continuous  
7 improvements, and process changes to improve their productivity.

8

9 The Company reports a variance of \$0.2 million more in the 12 months ending  
10 December 31, 2024, than was approved for cost recovery in Case No. U-21534,  
11 primarily due to the 20% disallowance directed by the Case No. U-21534 Final  
12 Order. See Exhibit A-24, Schedule N3 Line 323 for additional project details.

13

14 4) Customer Insight Platform Application Health

15 The Company is seeking recovery for \$4.3 million in the Customer Insight Platform  
16 Application Health project over the 12 months ending December 31, 2026, as  
17 shown on line 15 of Exhibit A-12, Schedule B5.7.2.

18

19 Through this project, a vendor, Powerley, will provide annual maintenance,  
20 upgrade, and other support services; key architecture components and cloud  
21 computing services, such as Amazon Web Services, to maintain user-facing  
22 functionalities for several DTE Electric systems. These systems include the DTE  
23 Insight mobile app for iOS and Android, which will receive ongoing software  
24 updates through this project to fix bugs and comply with operating system  
25 requirements. Energy Bridges will receive firmware support for real-time usage

Line  
No.

1 data from AMI meters and connected devices like Zigbee and Z-Wave. The  
2 Powerley Portal will support customer management, energy usage visualization,  
3 bill impact information, content management, budget/rate calculator, and Demand  
4 Response capabilities. Powerley, which offers reliable and proven specific  
5 expertise and an excellent track record of performance in this area, has developed  
6 and supports these systems for DTE external customers. Maintenance and upgrades  
7 are necessary to support new mobile operating systems and ensure customers retain  
8 the capabilities they pay for. Annually, this project will engage Powerley to  
9 maintain and deliver these capabilities. See Exhibit A-24, Schedule N3 line 326 for  
10 additional project details.

11

12 5) Customer Notifications Application Health

13 The Company is seeking recovery for \$3.0 million in the Customer Notifications  
14 Application Health project over the 24 months ending December 31, 2026, as  
15 shown on line 18 of Exhibit A-12, Schedule B5.7.2.

16

17 The Company sends an average of 165,000 notifications to customers daily via  
18 SMS, email, and voice messages. During large storm events, this number can rise  
19 to 1,000,000 notifications per day, totaling 60,000,000 notifications annually. This  
20 initiative funds the ongoing maintenance and support of the Company's  
21 Notification Platform. Sustainment activities include minor enhancements, new  
22 notification templates, production support, and maintenance of the application  
23 code. On-going support is crucial to maintain the Notification Platform and address  
24 issues identified in real-time. Sustainment of notification platforms is necessary to  
25 ensure continuity of transactional Customer Notifications across the enterprise.

Line  
No.

1 Customer notification modernization systems were launched in 2023, with  
2 migration from legacy systems continuing through 2024 and 2025. Maintenance  
3 of high delivery standards requires ongoing monitoring, configuration, bug fixes,  
4 and enhancements. This project will cover the skilled personnel to maintain these  
5 systems and processes, which is crucial for providing a stable customer experience  
6 and maximizing past capital investments. See Exhibit A-24, Schedule N3 lines 333,  
7 334 for additional project details.

8

9 6) Customer Relationship and Billing (CR&B) Program

10 The Company is seeking recovery for \$16.8 million in the Customer Relationship  
11 and Billing Program project over the 36 months ending December 31, 2026, and  
12 the historical spend of \$0.6 million in 2023, as shown on line 17 of Exhibit A-12,  
13 Schedule B5.7.2.

14

15 The CR&B Platform is a fully implemented system. The CR&B production  
16 environment needs to be regularly maintained to ensure the health, compliance, and  
17 strategic alignment of the SAP CR&B Platform while providing a high level of  
18 availability with accurate data to meet the business needs of the Customer Service,  
19 Billing and Metering, Distribution Operations, Energy Optimization, Treasury,  
20 Controller, Gas Operations, and Electric and Gas Sales and Marketing  
21 organizations and benefit customers with efficient and cost effective service.

22

23 The scope of the project from 2023 through 2026 supports achieving sustained and  
24 improved performance of the CR&B Platform while furthering strategic alignment  
25 with the platform vendors (e.g., SAP, OpenText). Included in this effort is the

Line  
No.

1 strategic oversight for the CR&B Platform including the development and delivery  
2 of the Technology Platform Plan. Beginning 2024, as part of the Company's on-  
3 going vendor negotiations and in alignment with the Company's strategic vision of  
4 cost optimization the scope and associated costs of the Automated Application  
5 Monitoring Health, Closed Loop COCL Application Health, Customer Information  
6 Technology Configuration Management and Customer Legacy Application Health  
7 projects will be integrated into the Customer Relationship and Billing Program.  
8 This integration will streamline DTE's processes, enhance operational efficiency,  
9 and ensure a more cohesive approach to managing customer relationships and the  
10 billing program. The Company anticipates that consolidation of these elements will  
11 result in improved service delivery, cost management, and alignment with DTE's  
12 long-term goals. See Exhibit A-24, Schedule N3 line 332 for additional project  
13 details.

14

15 The scope of the project is to provide ongoing support for the Azure Cloud APIs  
16 that interfaces the customer channels with the core Customer Relationship &  
17 Billing platform.

18

19 a) Customer Information Technology (CIT) Configuration Management

20 The Company is seeking recovery for a historical spend of \$0.9 million in Customer  
21 Information Technology (CIT) Configuration Management project in 2023, as  
22 shown on line 14 of Exhibit A-12, Schedule B5.7.2.

23

24 The scope of the project is to provide configuration, release, and compliance for the  
25 CIT and BPD portfolio assets, including SAP CR&B, Customer Self-Service

Line  
No.

1 Channels (Web, Mobile, IVR) and Customer ESB. See Exhibit A-24, Schedule N3  
2 line 324-325 for additional project details.

3

4 b) Customer Legacy Application Health

5 The Company is seeking recovery for a historical spend of \$0.5 million in Customer  
6 Legacy Application Health project in 2023, as shown on line 16 of Exhibit A-12,  
7 Schedule B5.7.2.

8 The scope of the project is to provide the development, testing and production  
9 buildings for Customer ESB support CIT channels which include (i) scheduled  
10 patching, which requires build, test and deployment, (ii) vulnerability management,  
11 which may require upgrades to Operating systems, hardware or software, and (iii)  
12 required enhancement builds, testing and deployments. See Exhibit A-24,  
13 Schedule N3 line 327-328 for additional project details.

14

15 c) Automated Application Monitoring Health

16 The Company is seeking recovery for a historical spend of \$0.2 million in  
17 Automated Application Monitoring project in 2023, as shown on line 13 of Exhibit  
18 A-12, Schedule B5.7.IT Projects <250K.

19 The scope of the project is to expand core CR&B operational visibility of existing  
20 solutions by adding technology and business process monitoring, optimizing  
21 alerting & notifications, and improving Standard Operational Procedures, Analytics  
22 and Dashboards.



Line  
No.

1 d) Closed Loop COCL Application Health

2 The Company is seeking recovery for a historical spend of \$.001 million in  
3 Automated Application Monitoring project in 2023, as shown on line 15 of Exhibit  
4 A-12, Schedule B5.7.IT Projects <250K.

5 The scope of the project is to support incremental improvements for customer  
6 transactions on the web such as billing, usage, payments, outage, program  
7 enrollment, collections closed loop, and MIMO (Move In Move Out) closed loop.  
8

9 7) DTE Mobile App Application Health

10 The Company is seeking recovery for \$3.6 million in the DTE Mobile Application  
11 health project over the 36 months ending December 31, 2026, and the historical  
12 spend of \$0.5 million in 2023, as shown on line 19 of Exhibit A-12, Schedule  
13 B5.7.2.

14 The DTE Mobile App Application Health project is one of two projects that were  
15 combined and previously known as Customer Digital Channels and Self-Service  
16 Program in Case No. U-21534. In 2024, approximately 19% of all self-serve  
17 interactions were completed by customers using the DTE Mobile App, which  
18 primarily provides customers self-serve options for outage, payments, bill access  
19 and some program management.

20

21 For the Outage transaction, the DTE Mobile App is the primary channel of choice  
22 for customers; 42% of outage interactions are completed using the DTE Mobile  
23 App. The DTE Mobile App, initially launched 14 years ago, is a native application  
24 designed for both Android and iOS users. For several years post-launch, the

Line  
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1 Company maintained the application in sustainment mode and did not allocate  
2 resources towards upgrading the App's technology, user experience, or introducing  
3 new self-service features. Consequently, the application operated on outdated code,  
4 posing challenges to maintaining the performance of the channel and increasing the  
5 potential risk to its resiliency, especially during significant events such as storm.

6  
7 In 2023, the Company undertook an investment to rewrite the DTE Mobile App  
8 using updated, modern technology, while also enhancing the user experience to  
9 offer customers a more user-friendly mobile application. While the primary focus  
10 of the rewrite was to improve resiliency and the ability to effectively maintain the  
11 Mobile App, the rewrite also resulted in improvements to the Mobile App  
12 Completion Rate and digital adoption by customers. For example, the Company  
13 achieved a 2% increase in Payments Digital Completion Rate and 3% increase in  
14 Payments Digital Engagement Rate from 2023 to 2024. Given that the Mobile App  
15 serves as a primary channel for customers, this project will implement essential  
16 sustainment activities to ensure the Mobile App remains functional, resilient,  
17 secure, and aligned with business needs. These activities encompass operational  
18 monitoring, bug fixes, compatibility with new versions of mobile operating  
19 systems, performance optimization, security updates, and minor enhancements.  
20 These efforts are aimed at maintaining key customer transactions and improving  
21 the digital self-service metrics. See Exhibit A-24, Schedule N3 line 338 for  
22 additional project details.

Line  
No.

1        8) DTE Newlook Website Application Health

2            The Company is seeking recovery for \$4.5 million in the project over the 36 months  
3            ending December 31, 2026, and the historical spend of \$1.5 million in 2023, as  
4            shown on line 20 of Exhibit A-12, Schedule B5.7.2.

5  
6            The DTE Newlook Website Application Health project was one of two projects that  
7            were combined and previously known as Customer Digital Channels and Self-  
8            Service Program in Case No. U-21534. Web digital customer transactions continue  
9            to run on legacy platforms, which is referred to as the “Newlook Website” in the  
10           instant case. For example, substantial portions of the customer Web experience run  
11           on IBM WebSphere Portal (version 8), which IBM no longer supports. While the  
12           Company is investing in transitioning away from aging platforms and has made  
13           significant strides in migrating key digital self-service transactions to the Cloud,  
14           critical assets such as customer Web login, Billing Web, portions of Payment Web,  
15           customer profile settings, and all Web transactions for Commercial and Industrial  
16           customers remain on legacy web platforms. Continued investments are necessary  
17           to maintain these critical assets until they are migrated and can be fully retired. The  
18           DTE Newlook Website Application Health project will continue to provide  
19           essential sustainment activities and fund minor enhancements to the legacy  
20           platform, enabling the Company to maintain key customer transactions during the  
21           ongoing transformation (migration to the Cloud). As discussed in the following  
22           sections for sustainment and strategic projects and shown in Exhibit A-12, Schedule  
23           B5.7.2 on the referenced line numbers: Digital Channels Transformation Program  
24           (line 33), Web Billing and Profile Settings Cloud Migration (line 38), and Payment  
25           Self-Service (line 54), the Company plans to make significant progress towards

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No.

1 completing the Web migration from legacy platforms to the Cloud in 2025 and  
2 2026. See Exhibit A-24, Schedule N3, line 342 for additional project details.

3

4 9) Outage WISMO, PPS and Map Application Health

5 The Company is seeking recovery for \$3.0 million in 2024-2025 bridge period and  
6 \$5.3 million in 2026 test period capital, as shown on line 21 of Exhibit A-12,  
7 Schedule B5.7.2., for the Outage WISMO, PPS and Map Application Health  
8 project.

9

10 With the implementation of the Error Free Communications – Outage Status (EFC)  
11 initiative, three significant core assets, Where-is-my-Order (WISMO), Premise  
12 Power Status (PPS), and the Outage Map, were developed to support the Outage  
13 Management and Storm processes. These core assets need to be sustained on an on-  
14 going basis to support during Blue Sky conditions and ensure their uptime and  
15 resiliency to perform during storm conditions, and for these systems to be able to  
16 adapt to changes and improvements as we make progress toward DTE’s long-term  
17 EFC goals and objectives.

18

19 This project will sustain the EFC Systems and include implementing process  
20 changes and hardware upgrades, remediating defects, developing minor  
21 enhancements, and load-testing the Systems to simulate catastrophic storm  
22 scenarios (e.g., one million outages scenario). The project will also provide funding  
23 to optimize the Outage Map load process and refine and optimize the performance  
24 of and integration between the EFC Systems and other systems like ADMS and  
25 CR&B. Additionally, the project will remedy security vulnerabilities, apply

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No.

1 mandated patches, and perform routine maintenance required to maintain the health  
2 of these EFC assets in the Cloud. These sustainment activities need to be performed  
3 on a quarterly basis or as recommended by the technology vendor to avoid  
4 unplanned outages. In 2025-2026, this project will continue the migration of PPS  
5 into WISMO and the use of WISMO versus CRM by the Contact Center, which  
6 will optimize the performance of these systems, ensure their resiliency, and reduce  
7 latency in providing customer updates through consolidation of these  
8 functions. Additionally, this project will provide funding to maintain all outage  
9 reporting and status dashboards that are used daily and during storm. See Exhibit  
10 A-24, Schedule N3, lines 343, 344 for additional project details.

11  
12 10) Hybris Application Health

13 The Company is seeking recovery for \$6.4 million in the Hybris Application Health  
14 project over the 36 months ending December 31, 2026, and the historical spend of  
15 \$2.2 million in 2023 as shown on line 22 of Exhibit A-12, Schedule B5.7.2.

16  
17 The Hybris Application Health project is an annual investment that will continue  
18 in 2026. Through this project, the Hybris Software Solution, an e-commerce  
19 delivery platform, will allow the Company to design and deliver non-metered  
20 products (products that do not require a meter for billing purposes, e.g., Surge  
21 Protection Program, TreeGuard Assurance, Smart Savers, and Smart Currents) in  
22 conjunction with existing metered offerings. These systems require regular  
23 production deployments to support daily operations and effective delivery of  
24 service to customers. The Hybris platform is a software-as-a-service solution from  
25 SAP which typically issues quarterly updates. To align with this release cycle, DTE

Line  
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1 must continually maintain vendor-supported versions of the platform while  
2 enhancing its performance and scalability to accommodate new capabilities and  
3 functionalities. For instance, the company was previously utilizing a 2005 version  
4 of the Hybris platform, which was slated to reach its end-of-life in March 2023  
5 according to the vendor. In response, the project successfully upgraded the platform  
6 in 2023 to the supported version 2211 of SAP Commerce Cloud and SAP  
7 Marketing Cloud.

8

9 The Company reports a variance of \$2.5 million more in the 36 months ending  
10 December 21, 2025, than approved for cost recovery in Case No. U-21534. Of this  
11 amount, \$0.5 million is due to disallowances of 10% in 2023 and 20% in 2024 and  
12 2025 directed by the Case No. U-21534 Final Order. The remaining \$2.0 million is  
13 due to an expanded scope of upgrading the SAP cloud platform, including  
14 Commerce and C4C upgrades and associated vendor charges for the upgrade. See  
15 Exhibit A-24, Schedule N3 line 348 for additional project details.

16

17 11) MIGreenPower Program Stabilization – Sustainment category

18 The Company is seeking recovery for \$4.8 million in this program over the 36  
19 months ending December 31, 2026, and has a historical spend of \$1.2 million in  
20 2023 as shown on line 23 of Exhibit A-12, Schedule B5.7.2.

21

22 This project sustains and supports the MIGreenPower applications in production by  
23 making necessary changes and updates to the existing SAP applications (CR&B,  
24 ISU) to support the renewable business as projects are completed. See Exhibit A-  
25 24, Schedule N3 line 352 for additional project details.

Line  
No.

1 12) Service Cloud Product Support for Customer Document Submission

2 The Company is seeking recovery for \$0.3 million in the Service Cloud Product  
3 Support for Customer Documentation Submission project over the 12 months  
4 ending December 31, 2024, and the historical spend of \$0.8 million in 2023 as  
5 shown on line 25 of Exhibit A-12, Schedule B5.7.2.

6

7 This project will provide DTE Electric's Customer Service Organization with a  
8 long-term solution for customers to submit documents for verification and approval  
9 (i.e., Contact Center, Revenue Management and Protection (RM&P) and Collection  
10 Exceptions). The document submission portal is the only secure way for the  
11 Customer Service organization to obtain documents from customers. When the  
12 document submission process is broken, it has an operational impact on customers  
13 trying to complete Move-in/Move-out (MIMO) transactions, enrollment into  
14 payment programs such as low-income, obtain medical holds, etc.

15

16 The Company reports a variance of \$0.4 million more than in the 12 months ending  
17 December 31, 2023, than was approved for the cost recovery in Case No. U-21534.  
18 This increase in costs reflect additional labor costs needed to address technical  
19 challenges and the extension of the project schedule into 2024. See Exhibit A-24,  
20 Schedule N3 line 357 for additional project details.

21

22 13) Smart Customer Mobile (SCM) – Saas Cloud License Deployment

23 The Company is seeking recovery for \$1.2 million in the Smart Customer Mobile  
24 (SCM) – Saas Cloud License Deployment project over the 24 months ending  
25 December 31, 2026, as shown on line 26 of Exhibit A-12, Schedule B5.7.2.

Line  
No.

1 This project represents a three-year capital investment to procure new licenses for  
2 the Smart Customer Mobile (SCM®) platform, which includes the SCM® Agency  
3 – Customer Web Portal and the SCM® Agency – Customer Service Portal. This  
4 platform is essential for Revenue Management and Protection (RMP) and supports  
5 state agencies in managing DTE Electric and Gas accounts, particularly for  
6 assisting low-income customers. The platform is critical for over 1000 agencies and  
7 120 utility user subscribers. It enables account management and payment  
8 applications for DTE Electric customers with functionalities including user  
9 management (My Account), account lookup and pledge making (Dashboard),  
10 payment capabilities, administrator/CSR capabilities, and account notifications.  
11 The Company last purchased a license for the platform in 2021. This investment  
12 ensures the platform’s continued operation and enhancement and support for its  
13 technical solution and architecture, through hardware and environment upgrades,  
14 security updates, and software releases, to prevent service disruption and support  
15 continuous improvements. See Exhibit A-24, Schedule N3, lines 358 - 359 for  
16 additional project details.

17

18 14) Supporting Capabilities Test Data and Test Data Management

19 The Company is seeking recovery for \$1.5 million in the Supporting Capabilities  
20 Test Data and Test Data Management project over the 36 months ending December  
21 31, 2026, as shown on line 27 of Exhibit A-12, Schedule B5.7.2.

22

23 The Supporting Capabilities Test Data and Test Data Management project will  
24 continue into 2026. This project provides vendor support for the SAP Customer  
25 Relationship and Billing (CR&B) application team’s generation of test data to help



Line  
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1 self-service channels, Assisted Channel, and Training with their sustainment and  
2 project testing activities. The vendors coordinate regression and performance test  
3 data with the team and maintain and conduct monthly runs of the regression scripts  
4 to prepare for successful production launches. Where a solution is customer-facing,  
5 vendors ensure the customer-facing Website, and its corresponding back-end  
6 system can handle the load under certain significant events such as during an  
7 Outage.

8

9 The Company reflects a variance of \$0.2 million more in the 24 months ending  
10 December 31, 2025, than was approved for cost recovery in Case No. U-21534 due  
11 to the 20% disallowance directed by the Case No. U-21534 Final Order. See Exhibit  
12 A-24, Schedule N3 line 362 for additional project details.

13

14 15) Web Transactions Application Health

15 The Company is seeking recovery for \$10.0 million in the Web Transactions  
16 Application Health project over the 24 months ending December 31, 2026, as  
17 shown on line 28 of Exhibit A-12, Schedule B5.7.2.

18

19 Over the past several years, the Company has made significant progress in  
20 migrating and transforming customer self-service digital transactions from legacy  
21 web platforms to the Cloud. Applications now hosted in the Cloud include the  
22 Outage Center, Police and Fire Outage Reporting, Municipality Outage Reporting,  
23 Payments, Customer Move-In / Move-Out / Transfer, MIMO Order Tracker,  
24 Collections Payment Agreement, Collections Payment Extension, Collections  
25 Reconnect, Web Registration, and Customer Address Search. The Web remains the

Line  
No.

1 primary channel for customer self-service; in 2024, 29% of all interactions were  
2 completed on the Web. Additionally, the adoption of self-service has improved  
3 significantly for transactions migrated to the Cloud; in 2024, 40% of Outage  
4 transactions were completed on the Web, along with 20% of MIMO transactions,  
5 20% of Collection transactions, and 10% of Payment transactions.

6  
7 Given the Web's role as the primary customer channel, this project supports  
8 essential sustainment activities to ensure that Web-based transactions in the Cloud  
9 remain functional, secure, and aligned with business needs. These activities include  
10 operational monitoring, bug fixes, performance optimization, security updates, and  
11 minor enhancements. These efforts aim to maintain key customer transactions and  
12 improve digital self-service metrics. These enhancements will be developed using  
13 bi-weekly sprints, with regular releases throughout 2025 and 2026. Specific work  
14 items will be identified and prioritized for each sprint based on customer value,  
15 security, and technical criticality. Key metrics for prioritization include the Digital  
16 Engagement Rate (which supports call volume reduction), Transaction Completion  
17 Rate, System Availability, Complaint Reduction, Vulnerability Count, Planned  
18 Outage Reduction, and Unplanned Outage Reduction. See Exhibit A-24, Schedule  
19 N3, lines 363, 364 for additional project details.

20

21 *3. Return-to-Health*

22 **Q87. Please explain the Customer Service investments in the 'Return-to-Health'**  
23 **category.**

24 A87. The Company is seeking recovery for \$25.0 million in the Return-to-Health  
25 category over the 36 months ending December 31, 2026, and the historical spend

Line  
No.

1 of \$14.8 million in 2023, as shown in lines 29 through 38 of the Capital  
2 Expenditures Exhibit A-12, Schedule B5.7.2. These investments are described  
3 below.

4

5 (1) Contact Center Infrastructure

6 The Company is seeking recovery for \$0.2 million in Contact Center Infrastructure  
7 project over the 12 months ending December 31, 2024 and the historical spend of  
8 \$0.6 million in 2023, as shown on line 30 of Exhibit A-12, Schedule B5.7.2.

9

10 This project provided key hardware and software upgrades to the Contact Center  
11 infrastructure, which ensures the Contact Center is running on the latest and most  
12 supported hardware and software versions provided by the vendors. In 2023-2024,  
13 DTE implemented a new cloud technology solution to replace the Company's  
14 previous IVR, telephony, and workforce management applications. This all-in-one  
15 solution has set the foundation for future growth and capabilities.

16

17 The capital requested for this project reflects a variance of \$0.2 million more in the  
18 12 months ending December 31, 2023, than was approved for the cost recovery in  
19 Case No. U-21534. Of this amount, \$0.07 million is due to the 10% disallowance  
20 directed by the Case No. U-21534 Final Order and the remaining \$0.13 million is  
21 because of project schedule extension into 2024. The extension was caused by  
22 delays in hardware procurement and the need for additional time to safely update  
23 key systems without causing a major outage. See Exhibit A-24, Schedule N3 lines  
24 366, 367 for additional project details.

Line  
No.

1 (2) Digital Channels Transformation Program

2 The Company is seeking recovery for \$9.8 million in the Digital Channel  
3 Transformation program over the 36 months ending December 31,2026 and the  
4 historical spend of \$2.7 million in 2023, as shown on line 33 in Exhibit A-12,  
5 Schedule B5.7.2.

6

7 The Company has made significant improvements in enabling customers to interact  
8 with DTE Electric through digital Web and Mobile App channels for the five key  
9 customer transactions (MIMO, Outage, Collection, Billing, and Payment). While  
10 most of these transactions have been transformed in the Cloud, other critical Web  
11 assets, such as customer login, are aging and run on fragmented technologies. The  
12 Digital Channels Transformation Program from 2024 to 2026 will focus on  
13 transforming the customer Web login application / platform. This will include  
14 phasing out un-supported technologies, simplifying the architecture, reducing  
15 failure points, enhancing security, and improving the functionality for customers  
16 for online account creation, password management, and login.

17

18 In 2024, the Company completed a comprehensive assessment that recommended  
19 a series of near- and long-term solutions to address key pain points in the login  
20 platform. The long-term solution includes migrating from the current sub-optimal  
21 hybrid solution, consisting of a home-grown Web security token and a minimally  
22 implemented using Customer Identity and Access Management token, to an  
23 industry-leading CIAM solution. This scope was added in 2025. Benchmarking  
24 with peer utilities has also confirmed that most utility companies leverage an  
25 industry solution for login, indicating that DTE is lagging in this area.

Line  
No.

1 Customer login and identity management have been long-standing challenges and  
2 opportunities for the Company. Most Web complaints involve customers unable to  
3 access or retrieve their online accounts, leading to issues with logging in to access  
4 or pay their bills online. Other pain points include a cumbersome password  
5 recovery process, browser extension compatibility issues, the inability to separate  
6 login email from the e-bill program, and cross-channel login support (e.g., Web and  
7 Mobile App). Additionally, the current login platform does not support multi-  
8 factor authentication, a critical feature for improving the security of the Company's  
9 channels. This project will support the implementation of a new login platform and  
10 all necessary work to integrate the new solution across the digital channels. See  
11 Exhibit A-24, Schedule N3 lines 371 - 374 for additional project details.

12

13 (3) Web Billing and Profile Management Cloud Migration

14 The Company is seeking recovery for \$4.5 million over the 12-month test year  
15 ending December 31, 2026, in the Web Billing and Profile Management Cloud  
16 Migration project as shown on line 38 in Exhibit A-12, Schedule B5.7.2.

17

18 The scope of the project is to migrate the DTE Energy Newlook Website from on-  
19 premises servers (legacy Web) to the cloud (AWS), focusing on the following  
20 critical Web experiences: the "current bill" page, billing history, billing programs,  
21 and customer profile settings. This migration will enhance the reliability and  
22 efficiency of these frequently accessed services. By moving to the Cloud, the  
23 Company can mitigate risks associated with the current un-supported technology  
24 platform, improve customer satisfaction, and support call reduction efforts. The  
25 Cloud platform will also enable the development of additional self-service

Line  
No.

1 functionalities, providing a more comprehensive and personalized customer  
2 experience. Employees will benefit from agile practices, allowing for more  
3 efficient monitoring, operation, and enhancement of Web assets.

4  
5 The current bill page alone is accessed approximately one million times by  
6 customers over a 30-day period, making its efficient operation on Cloud  
7 technologies crucial. Migrating the current bill page to the Cloud will enable more  
8 efficient enhancements to the customer's digital experience, representing a  
9 significant opportunity to improve customer satisfaction by providing a more self-  
10 service experience and eliminating the need customers to call the DTE Contact  
11 Center. Currently, approximately 10% of customers log into the DTE Website  
12 before calling (~300,000 calls annually), indicating they are unable to find what  
13 they need online. Today, the current bill page serves as the customer's Web landing  
14 page after logging in and currently offers basic account and bill information but  
15 lacks critical features necessary for a comprehensive, personalized customer  
16 experience. Benchmarking has shown that DTE's Web landing page lacks key  
17 features compared to peer utilities such as ComEd and PSE&G. Migrating to the  
18 Cloud will allow for more robust and scalable enhancements, ultimately leading to  
19 a better customer experience and operational efficiency. While the primary scope  
20 of this project is a Cloud migration, it will also include re-design of the landing  
21 page to address customer needs that span beyond billing, given that this is the first  
22 page customer's access when logging in. See Exhibit A-24, Schedule N3 line 380  
23 for additional project details.

Line  
No.

1 (4) Migrate SAP Marketing Cloud to SAP EMARSYS

2 The Company is seeking recovery for \$2.1 million in the Migrate SAP Marketing  
3 cloud to SAP EMARSYS project over the 12 months ending December 31, 2025,  
4 as shown on line 34 in Exhibit A-12, Schedule B5.7.2.

5  
6 This project involves the transition of DTE Electric's marketing capabilities from  
7 SAP Marketing Cloud to SAP EMARSYS ahead of support for the former  
8 scheduled to end by 2026. The move is crucial for maintaining and improving  
9 customer communication across various channels like SMS, email, voice, and  
10 social media. The migration also addresses challenges such as inconsistent  
11 messaging across different marketing tools, manual data segmentation, data silos  
12 and governance issues, and high operational costs from managing multiple  
13 platforms. The project will establish and integrate the new SAP EMARSYS system  
14 with existing on-premises applications, redesign marketing to sales processes to  
15 leverage enhanced capabilities, and improve marketing spend traceability,  
16 omnichannel experience, and personalized marketing. The project will also  
17 implement SAP CDP to support data requirements for SAP EMARSYS. See  
18 Exhibit A-24, Schedule N3 line 375 for additional project details.

19

20 (5) SAP Commerce B2C storefront migration

21 The Company is seeking recovery for \$2.6 million in the SAP Commerce B2C  
22 storefront Migration over the 12 months ending December 31, 2025, as shown on  
23 line 36 in Exhibit A-12, Schedule B5.7.2.

Line  
No.

1 This project involves the migration of DTE Electric's SAP Commerce B2C  
2 storefront to a composable storefront (Spartacus) and integration of the storefront  
3 with Adobe Experience Manager (AEM) as the new content management system  
4 (CMS). Currently, the SAP Commerce cloud platform is used by customers to  
5 purchase or subscribe to DTE Electric products and services. The existing platform  
6 (Accelerator UI) will be unsupported by 2025, necessitating an update to the  
7 composable storefront. The migration offers several benefits, including increased  
8 flexibility to make changes to products and services, reduced costs and complexity  
9 by unifying B2B and B2C storefronts, faster deployment of new products and  
10 services, and enhanced content management with AEM, which reduces design and  
11 implementation time.

12

13 The project will be carried out in phases: first, migrating the SAP Commerce B2C  
14 storefront to Spartacus; and then integrating AEM as the new CMS. Key  
15 functionalities and capabilities include a shopping cart experience for B2C  
16 customers, collaboration with the experience design team for web content changes,  
17 a centralized content repository for customer access to terms and conditions and  
18 other documents, and security enhancements to eliminate vulnerabilities in the  
19 customer self-service channel. This project will streamline operations, reduce costs,  
20 and improve the customer experience by leveraging the latest headless commerce  
21 technology and integrated content management. See Exhibit A-24, Schedule N3  
22 line 377 for additional project details.



Line  
No.

1 (6) Systems, Applications, and Products (SAP) Upgrade Program

2 The Company is seeking recovery for \$3.6 million in the Systems, Applications,  
3 and Products (SAP) Upgrade Program over the 12 months ending December 31,  
4 2024, and the historical spend of \$3.3 million in 2023, as shown on line 37 of  
5 Exhibit A-12, Schedule B5.7.2.

6

7 This project implemented the latest release of SAP stacks and packs, updating core  
8 CR&B applications such as IS-U billing, Customer Relationship Management  
9 (CRM), Process Optimization (PO), and Business Warehouse (BW) to the 2025  
10 versions.

11

12 The Company reports a variance of 3.8 million more in the 12 months ending  
13 December 31, 2023, than was approved for the cost recovery in Case No. U-21534.  
14 Of this amount, \$0.3 million is due to the disallowances of 10% in 2023 directed  
15 by the Case No. U-21534 Final Order. The remaining \$3.5 million is attributed to  
16 increased costs associated with hardware replacement for CR&B applications in  
17 2024 and the extension of the project schedule into 2024. The schedule of the  
18 project was extended to complete the additional hardware replacement that was  
19 necessary to address security vulnerability issues and maintain asset health. See  
20 Exhibit A-24, Schedule N3 line 379 for additional project details.

21

22 *4. Discretionary Customer IT Projects*

23 **Q88. Which Customer IT projects are included in this section?**

24 A88. This section includes the Enhancement and Strategic categories of Customer IT  
25 Portfolio projects, organized as follows: Digital Self-Service Customer IT Projects;

Line  
No.

1 Operational Efficiency Customer IT Projects; and Customer IT Projects that  
2 Enhance Customer Interactions.

3

4 *a) Digital Self-Service Customer IT*

5 **Q89. How much historical, bridge, and test period capital is reflected in the instant**  
6 **case for the Company's digital self-service solutions?**

7 A89. In total, the Company is investing \$15.2 million in historical, bridge, and test period  
8 capital in support of the expansion and enhancement of its digital self-service  
9 solutions, which is allocated to the following projects as reflected in Exhibit A-12,  
10 Schedule B5.7.2 on lines 45, 52, and 54 for the Billing Web Self-Service, MIMO  
11 Web Self-Service, and Payment Web Self-Service, projects, respectively.

12

13 **Q90. How much of the \$15.2 million in capital included in the instant case was**  
14 **previously approved in a prior Commission rate order?**

15 A90. Of the total \$15.2 million in digital capital included in the instant case, \$17.5  
16 million was approved in Case No. U-21534, with the Company expecting to spend  
17 a net \$2.3 million less than was approved for recovery. See Table 8 below for the  
18 net result of the increases and decreases for each of these projects

Line  
No.1                      **Table 8                      U-21860 Incremental Digital Self-Service Capital**

2

| Project Name                | Approved<br>U-21534 Capital | Requested<br>U-21860 Capital | Incremental<br>Increase/ (Decrease) |
|-----------------------------|-----------------------------|------------------------------|-------------------------------------|
| Billing Web<br>Self-Service | \$1.5 million               | \$0.6 million                | (\$0.9 million)                     |
| MIMO Web<br>Self-Service    | \$11.4 million              | \$8.9 million                | (\$2.5 million)                     |
| Payment Web<br>Self-Service | \$4.6 million               | \$5.7 million                | \$1.1 million                       |
| <b>TOTAL</b>                | <b>\$17.5 million</b>       | <b>\$15.2 million</b>        | <b>(\$2.3 million)</b>              |

3

4                      The capital requested and approved for recovery in Case No. U-21534 includes the  
5                      total 2023-2024 bridge and 2025 test period capital as reflected in Exhibit A-12,  
6                      Schedule B5.7.3 in that case, while the capital reflected in the instant case includes  
7                      the total 2023 historical, 2024-2025 bridge, and 2026 test period capital in Exhibit  
8                      A-12, Schedule B5.7.2 in the instant case.

9

10           **Q91.    Can you explain the drivers of the net decrease in requested capital in this case**  
11           **relative to what was previously approved by the Commission in Case No. U-**  
12           **21534?**

13           A91.    Yes. The drivers of the net decrease of \$2.3 million capital being requested in this  
14           case are primarily related to changes in the Company's capital investments in the  
15           Billing, MIMO, and Payment Web Self-Service projects, as shown in Exhibit A-  
16           12, Schedule B5.7.2, and summarized below.

17

18           1) Billing Web Self-Service

Line  
No.

1 In Case No. U-21534, the Commission approved \$1.5 million in 2023-2024 bridge  
2 period capital for the Billing Web Self-Service project as shown on line 28 in  
3 Exhibit A-12, Schedule B5.7.3 in support of the scope of work as described in  
4 Company Witness Hatsios' testimony in Case No. U-21534. The Company spent  
5 a total of \$0.9 million less in 2023 historical (\$0.2 million) and 2024 bridge period  
6 (\$0.7 million), as reflected in Exhibit A-12, Schedule B5.7.2, Line 45 of the instant  
7 case, when it was determined that the Billing digital solution would be migrated to  
8 the Cloud platform in 2026 as part of the Web Billing and Profile Management  
9 Cloud Migration project, a Web return-to-health project, shown on line 38 in  
10 Exhibit A-12, Schedule B5.7.2. After completing discovery in 2024, it was  
11 identified that the primary scope of the project is to migrate and transform the  
12 "current bill" page on the Cloud, which currently serves as the customer landing  
13 page after login and is hosted on DTE's legacy Website. See the Customer IT  
14 Portfolio Return-to-Health section of my testimony above (Section VI.D.3) for  
15 additional details regarding that project. The Company will re-evaluate if a  
16 strategic Billing Web Self-Service project is needed after the transformation of the  
17 underlying platform is completed, which will include an end-to-end evaluation of  
18 the Web Billing experience.

19

20 2) MIMO Web Self-Service

21 In Case No. U-21534, the Company requested, and the Commission approved \$8.9  
22 million in 2023-2024 bridge, and \$2.5 million in 2025 test, period capital for the  
23 MIMO Web Self-Service project shown as shown on line 41 in Exhibit A-12,  
24 Schedule B5.7.3 in support of the scope of work described in Company Witness  
25 Hatsios' testimony in Case No. U-21534. The Company spent the approved total

Line  
No.

1 capital of \$8.9 million in 2023 and 2024, as reflected in Exhibit A-12, Schedule  
2 B5.7.2, Line 52 of the instant case, but decided to pause major enhancements to our  
3 MIMO digital solutions in 2025 and re-direct the capital investment and resources  
4 to fund the enhancements required in the Payment Merchant Fees project; thereby,  
5 creating a variance of \$2.5 million less than was approved for recovery in Case No.  
6 U-21534 for the MIMO Self-Service project.

7

8 Continued improvements in the MIMO digital self-service solutions will be  
9 supported in sustainment mode through the 2025-2026 Web Transactions  
10 Application Health project, discussed earlier in the Customer IT Portfolio  
11 Sustainment section (Section VI.D.2.15) of my direct testimony. This sustainment  
12 project will address defects and make minor enhancements that will increase the  
13 percentage of customers who are able to successfully complete their MIMO digital  
14 transaction, helping to further reduce call volumes. See Exhibit A-24, Schedule N3  
15 line 423-424 for additional project details.

16

17 3) Payment Web Self-Service

18 In Case No. U-21534, the Company requested, and the Commission approved \$1.1  
19 million in 2023-2024 bridge, and \$3.5 million in 2025 test, period capital for the  
20 Payment Web Self-Service project shown as shown on line 42 in Exhibit A-12,  
21 Schedule B5.7.3 in support of the scope of work described in Company Witness  
22 Hatsios' testimony in Case No. U-21534. The Company spent only \$0.1 million in  
23 2023 and 2024 on Payment Web Self-Service but is continuing to invest \$3.5  
24 million in 2025 bridge and \$2.0 million in the 2026 test period, as reflected in  
25 Exhibit A-12, Schedule B5.7.2, Line 54 of the instant case, to complete and expand

Line  
No.

1 on the scope of work as described in Company Witness Hatsios' testimony in Case  
2 No. U-21534. The net result is an incremental \$1.1 million in capital from what  
3 was approved for recovery in Case No. U-21534 for the Payment Web Self-Service  
4 project. See Exhibit A-24, Schedule N3 line 429 for additional project details.

5  
6 The re-design of the payment experience is timely to support the required 2025  
7 Web enhancements ahead of the Payment Merchant Fee project implementation,  
8 which is described in Section VI.D.4.d of my testimony, and which is intended to  
9 transition to the charging of a fee for customers who choose to use a credit or debit  
10 card to make a payment. For example, to continue offering automatic payments  
11 with a card and fee, the existing auto pay program must be enhanced. Enhancements  
12 will include providing customers with reminders before automatic payments are  
13 withdrawn and the ability to cancel automatic payments. As the Company delves  
14 deeper into the Payment Merchant Fee project, additional scope may be identified  
15 or impacted within Payments Web that will need to be addressed.

16

17 **Q92. In Company Witness Hatsios' direct testimony in Case No. U-21534, he**  
18 **described the impact of the Company's digital self-service investments on a**  
19 **reduction in live call volumes. What reduction in call volumes is the Company**  
20 **forecasting to achieve through its already approved and ongoing digital self-**  
21 **service capital investments?**

22 A92. The Company is forecasting that customer engagement in the digital self-service  
23 solutions will continue to increase as the Company further enhances and expands  
24 its digital self-service solutions. This increased engagement and use of the digital  
25 self-service solutions is forecasted to reduce live call volumes from 3.16 million in

Line  
No.

1 2024 to 2.8 million in 2028. The 3.16 million calls in 2024 includes ~216,000 in  
2 call reductions from the Collection transaction, which remain flat with no additional  
3 Collection call reduction in the Company's projection through 2028. Forecasted  
4 call volume reductions by transaction type are shown on page 2, line 9, columns (f)  
5 through (j) in Exhibit A-24, Schedule N5.

6

7 **Q93. Are the forecasted call volumes reflected in Exhibit A-24, Schedule N5 of the**  
8 **instant case different than those that were forecasted in Case No. U-21534?**

9 A93. Yes. The call volume forecast by transaction was updated to exclude call reductions  
10 from the Collection digital transactions after 2023 since the 2022-2025 Collection  
11 Self-Service project costs were disallowed for recovery in Case No. U-21534.  
12 Adjusting for this change, the 2024 year-end call volume is 3.38 million (the total  
13 call volume from the other four key transactions and Other and Short Calls), which  
14 is still lower, without accounting for the 216,000 Collection calls that were reduced  
15 in 2024, than the 3.47 million calls that were projected to be reduced in 2024 from  
16 Company Witness Hatsios' revised direct testimony in Case No. U-21534. The  
17 realized incremental 2024 call volume reduction of ~242,000 calls was seen across  
18 the remaining four transactions and the Other and Short Calls categories and  
19 provides support that customer engagement in the Company's digital solutions  
20 continues to grow, and calls are being reduced as a result. For details on the  
21 adjustment to Collection calls and the year-over-year call reductions by transaction  
22 from 2024 through 2028, see page 2, lines 2,3 in Exhibit A-24, Schedule N5.

23

24 **Q94. In Company Witness Hatsios' direct testimony in Case No. U-21534, he**  
25 **described how reductions in call volumes from the Company's digital self-**

Line  
No.

1           **service investments reduce the cost of handling live calls. What are the total**  
2           **cumulative call volume savings the Company is forecasting to achieve because**  
3           **of its forecasted call volume reductions?**

4    A94.   As seen in Exhibit A-24, Schedule N5, line 23, columns (l), the Company is  
5           forecasting to provide customers with a total cumulative net O&M savings of \$7.2  
6           million from 2024-2028, of which \$4.7 million is DTE Electric's portion shown on  
7           line 25, column (j), by reducing total call volume from 3.38 million in 2024, line 8,  
8           column (f), after adjusting for Collection calls, to 3.00 million calls by 2028, line  
9           8, column (j).

10

11   **Q95. Is the Company removing the forecasted call volume savings from its**  
12           **operating budget and its requested O&M recovery in the instant case?**

13    A95.   Yes. The Company is removing the annual call volume savings for the projected  
14           test year from its requested Customer Service O&M recovery in the instant case as  
15           reflected in Company Witness Sparks supporting Exhibit A-13, Schedule C5.7 on  
16           line 5, column (l) for Customer Records and Collection Expenses, and in Note 3.  
17           This reduction is also highlighted in Exhibit A-24, Schedule N5, line 25, column  
18           (h).

19

20           *b) Operational Efficiency Customer IT*

21   **Q96. What is included in this section of your testimony?**

22    A96.   This section of my testimony will discuss four projects that align with enabling  
23           operational efficiencies, resiliency, and stability in the Contact Center, advanced  
24           data analytics projects that capture additional operational efficiencies and improve  
25           the customer experience, and projects that allow the Company to improve the



Line  
No.

1 quality and efficiency of the SAP Customer Relationship and Billing (CR&B)  
2 System.

3

4 **Q97. Can you please describe projects that deliver operational efficiencies in the**  
5 **Contact Center?**

6 A97. Yes. The Company is investing \$1.5 million in 2025 bridge period capital to  
7 enhance the functionality of its Contact Center systems and platforms, improve  
8 customer accessibility to the telephony systems during peak call times by providing  
9 more stability and resiliency during a major storm event, and enhance the ability of  
10 the Contact Center to reduce the Average Handle Time (AHT) of customer calls  
11 from improving CR productivity and capturing operational efficiencies. This  
12 project is included in Exhibit A-12, Schedule B5.7.2, and is summarized below.

13

14 1) Contact Center Technology Upgrades

15 In 2024, DTE implemented a new Cloud technology solution to replace the  
16 Company's previous IVR, telephony, and workforce management applications.  
17 The new platform is an all-in-one solution that sets the foundation for enabling  
18 additional call handling capabilities and making the Company's Contact Center  
19 platform more efficient, stable, and resilient. Since the 2024 investment was  
20 focused on replacing the previous platform like-for-like, it did not include changing  
21 or adding more functionality. The Contact Center Infrastructure project is discussed  
22 above in the Customer IT, Return-to-Health section of my testimony (Section  
23 VI.D.3.1).

Line  
No.

1 The Company is investing \$1.5 million in 2025 bridge period capital in the Contact  
2 Center Technology Upgrades project shown on line 40 of Exhibit A-12, Schedule  
3 B5.7.2 to build on the initial foundation established in 2024 by adding new  
4 capabilities that support the Contact Center to achieve its long-term operational and  
5 customer experience / satisfaction goals and metrics (e.g., lower AHT, higher  
6 service level, and higher First Contact Resolution). These new capabilities will  
7 provide for:

8 1) an improved IVR experience through natural language processing that allows  
9 customers to speak naturally to the IVR. Combining this conversational capability  
10 with more robust data integrations to the Company's backend systems will allow  
11 the IVR to more quickly help route customers and perform more complicated  
12 interactions such as when an address is required;

13 2) a streamlined CR experience which makes navigation of screens and access to  
14 information more readily available so that CRs can more efficiently assist  
15 customers with requests and inquiries;

16 3) robust data, reporting and quality tools that support real-time monitoring of calls  
17 and call handling quality to optimize staffing to meet demand and identify  
18 opportunities for CR training and continuous improvement; and

19 4) the integration of chat functionality into the platform for a single solution.  
20

21 As discussed above, this investment will enable CRs to be more productive as more  
22 information will be contained in one system, creating a modern agent desktop that  
23 brings together information from multiple systems such as Customer Relationship  
24 Management (CRM), outage status systems, and various grid/meter information  
25 systems into a consolidated desktop interface, reducing search time, and improving

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No.

1 navigation and overall call handle time. The enhancements will also provide one  
2 place for handling chat and live calls, enabling a continuous and proactive customer  
3 experience when performing a key customer transaction. Other features of the new  
4 system include more access to real-time metrics and guidance to help agents and  
5 leaders track performance. These include: 1) the opportunity for proactive alerts to  
6 leaders based on customer sentiment to see in real-time if an escalation is needed;  
7 2) greater visibility of real-time demand and performance metrics such as call  
8 volumes and service level within the system; and 3) use of a more effective, virtual  
9 callback technology that ensures a CR is ready to accept the call before calling the  
10 customer back so there is zero wait time.

11 With these additional capabilities provided by the new Contact Center platform, the  
12 Company anticipates a reduction in AHT once the 2025 capabilities are fully  
13 implemented, which will contribute towards a reduction in Contact Center O&M  
14 expenses. See Exhibit A-24, Schedule N3, line 415 for additional project details.  
15

16 **Q98. How is the Company leveraging Advanced Analytics to capture operational**  
17 **efficiencies that reduce O&M costs and improve the quality of call handling?**

18 A98. In the Case No. U-21534 Final Order, the Commission approved \$5.5 million in  
19 2023-2025 capital for the Advanced Analytics (AA) Use Cases Implementation  
20 project to fund analytics resources and technologies that enable the Company to  
21 capture operational efficiencies and provide greater insight into customer segments,  
22 behaviors, and improving customer satisfaction and the customer experience. The  
23 Company's actual spend for this project is projected to be \$2.0 million in capital in  
24 2023-2025, which includes \$3.0 million less in 2025 bridge period capital due to  
25 re-prioritization of the project capital to fund other IT capital projects.

Line  
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1           2)       2026 AA Use Case #1 – Automation of Call Quality Assessments

2           The Company is seeking recovery for \$2.5 million in 2026 test period capital in the  
3           instant case for the 2026 Advanced Analytics (AA) Use Cases project as shown on  
4           line 39 of Exhibit A-12, Schedule B5.7.2. Of the \$2.5 million in 2026 test period  
5           capital, \$1.3 million will fund the AA use case to develop and deploy a Large  
6           Language model (LLM) to automate ~50% of the call quality assessment process  
7           and integrate the model into the Power Automate application. By feeding the model  
8           call transcripts, speech analytics call categorization, audio recordings, and screen  
9           recordings, it can evaluate and rate CR call handling performance, significantly  
10          reducing the time required for Contact Center call quality analysts to manually  
11          listen to and evaluate calls. Automating the process increases the volume of calls  
12          that are quality checked, enhances the efficiency and consistency in call quality  
13          assessments, and provides faster feedback to CRs on ways to improve their call  
14          handling such as through refresher training. Automation of the call quality  
15          monitoring is estimated to provide ~\$200,000 in O&M savings.

16

17          3)       2026 AA Use Case #2 – Automating CR Notes

18          The Company is seeking recovery for \$2.5 million in 2026 test period capital in the  
19          instant case for the 2026 Advanced Analytics (AA) Use Cases project as shown on  
20          line 39 of Exhibit A-12, Schedule B5.7.2. Of the \$2.5 million in 2026 test period  
21          capital, \$1.2 million will fund the second 2026 AA use case, which will focus on  
22          developing advanced analytics models designed to reduce the AHT of calls by  
23          automating the notes taken by CRs during or after a call. Currently, CRs manually  
24          enter notes into the CRM system for ~30% of annually handled calls, particularly  
25          for inquiry calls as it provides visibility into why the customer called. While these

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1 notes are valuable for follow-up tasks, addressing subsequent customer calls, and  
2 understanding the reason for calls when there is no transaction completed, this  
3 process adds to AHT, which translates into Contact Center O&M costs, longer wait  
4 times, and potentially lower service levels.

5  
6 Using advanced analytics algorithms that leverage Natural Language Processing  
7 and build a LLM model to automate the note-taking process by analyzing call  
8 transcripts, the Company can reduce AHT by ~20 seconds for 30% of the calls in  
9 which the CR enters notes for an estimated savings of ~\$300,000 annually.  
10 Automating the CR note-taking process also provides other benefits, such as more  
11 comprehensive notes than those entered manually, enabling the Company to  
12 analyze customer calls and look for opportunities to improve the quality of their  
13 call experience or deflect calls to self-service. See Exhibit A-24, Schedule N3, line  
14 405 for additional project details.

15

16 **Q99. Are any IT efficiency projects intended to improve the quality and efficiency**  
17 **of the Customer CR&B system and reduce system downtime?**

18 A99. Yes, there is one project that is intended to provide these benefits. The project's  
19 details are as follows.

20

21 4) Transform and Modernize Process Orchestration (PO) Architecture

22 The Company will invest \$1.0 million in 2026 test period capital in the Transform  
23 and Modernize the Process Orchestration (PO) Architecture project on line 44 of  
24 Exhibit A-12, Schedule B5.7.2 to alleviate system bottlenecks due to network  
25 traffic and growing functionalities in the CR&B system. The Commission approved

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1 for recovery \$1.0 million in 2025 test period capital for this project in the Case No.  
2 U-21534 Final Order. This project has since been rescheduled into 2026, and as  
3 such, is included as part of the Company's request to approve capital recovery in  
4 the 2026 test period in the instant case.

5  
6 This project remains critical. As the Company enables more capabilities in its  
7 customer channels and the CR&B system, it creates additional stress and burden  
8 for the PO to ensure increasingly complex jobs and functions perform as expected.  
9 During periods of high traffic, such as during a storm or in the fall with the influx  
10 of college move-ins, the Company's transactional system and digital channels must  
11 scale up to handle the additional workload or risk an unplanned system outage. By  
12 upgrading the PO to a more robust architecture, DTE Electric will be able to reduce  
13 unplanned system outages that disrupt the Company's ability to serve customers  
14 either digitally or through the Contact Center.

15  
16 While the system is typically back up in ~3 hours during an unplanned outage, it  
17 takes at least eight hours to identify the root cause and implement a longer-term fix  
18 to stabilize the system. The cost of CRs who wait for the system to be restored  
19 during unplanned system outages could be considerable. If it takes ~3 hours for the  
20 system to come back up, assuming the Company can reduce unplanned system  
21 outages from 10 to 3 by 2029, by multiplying this idle wait time by the average  
22 number of CRs per year between 2027 and 2029 and the hourly labor cost of a CR,  
23 this project can reduce the O&M cost of CR wait time by ~\$340,000. See Exhibit  
24 A-24 Schedule N3, line 409 for additional project details.

Line  
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1 *c) Customer IT Projects that Enhance Customer Interactions*

2 **Q100. Can you describe the Company's rationale for investing capital in projects**  
3 **that will enable "Enhanced Customer Interactions"?**

4 A100. The Company's strategy to enhance customer interactions is simple – improve the  
5 customer experience and the effectiveness and efficiency with which the Company  
6 manages customer interactions, by prudently investing in capital projects that  
7 improve the quality of the data and information provided to customers during these  
8 interactions.

9

10 **Q101. Which of the capital projects are you sponsoring in your testimony that are**  
11 **intended to "Enhance Customer Interactions"?**

12 A101. I will discuss seven projects in my testimony that are intended to Enhance Customer  
13 Interactions, five of which are included in Exhibit A-12, Schedule B5.7.2 (e.g.,  
14 Customer Communications, Customer Communications Phase 2, Error Free  
15 Communications – Outage Status, Outage WISMO, PPS and Map Enhancements,  
16 Customer Closed Loop Development). The other two projects are related to  
17 investments in the Error Free Communications project, Operational Technology  
18 and EFC (line 47) and Other Grid Modernization (line 48) shown in Exhibit A-12,  
19 Schedule B5.4 Technology and Automation, which is sponsored by Company  
20 Witness Rademacher.

21

22 1) Customer Service Communications and Customer Service  
23 Communications Phase 2

24 The Company invested \$4.7 million in 2023 historical period capital for the first  
25 phase of the Customer Service Communications project, as shown on line 48 in

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1 Exhibit A-12, Schedule B5.7.2, of which \$3.9 million was approved for recovery  
2 in Case No. U-21534. This investment was for the implementation of a new  
3 customer notification platform – Message Broadcast – the scope of which was  
4 completed in 2023. For Phase 2 of the project, the Company invested \$2.9 million  
5 in 2024 bridge period capital, as shown on line 49 in Exhibit A-12, Schedule B5.7.2,  
6 of which \$2.0 million was approved for recovery in Case No. U-21534. See Exhibit  
7 A-24 Schedule N3, line 417 for additional project details.

8

9 Phase 2 of the project included the migration of 99% of all customer notifications  
10 to the new Message Broadcast platform, and the leveraging of the new platform to  
11 enhance the quality and effectiveness with which we communicate with customers.  
12 It also provided the ability to create, customize, catalog, and store customer  
13 notifications with delivery confirmation, so that the Company has visibility into  
14 which customers did not receive which notifications, and the use of the platform's  
15 tools to ensure the integrity of the customer contact data, to quickly create Messages  
16 On Demand (MODs) by an assortment of methods, including list, zip code,  
17 electrical device, and geography, and to be able to provide customers the ability to  
18 communicate with us via SMS/texting.

19

20 To complete Phase 1 of the project, the Company spent an incremental \$0.9 million  
21 in 2023 due to Message Broadcast Licensing fees and is seeking recovery of this  
22 incremental spend in the instant case. The Company is also seeking recovery of  
23 the incremental \$0.9 million in 2024 bridge period capital for Phase 2 in the instant  
24 case due to higher than estimated costs to complete the scope of Phase 2 of the  
25 project. See Exhibit A-24 Schedule N3, line 418 for additional project details.



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No.

1           2)       Error Free Communications (EFC) – Outage Status

2           As previously described in Company Witness Hatsios’ direct testimony in Case  
3           Nos. U-21297 and U-21534, the Company launched its EFC initiative to  
4           significantly improve the quality of the information provided to customers during  
5           an outage, which includes real-time power status at the customer’s premise (i.e.;  
6           home or business), power restoration accuracy and timeliness (i.e.; confirmation  
7           that power has been restored), first estimate accuracy (i.e.; accuracy with which the  
8           Company provides customers with an estimated time of restoration), and successful  
9           outage notification delivery (i.e.; percentage of customers who receive required  
10          outage notifications).

11

12          In Case Nos. U-21297 and U-21534, the Commission collectively approved for  
13          recovery a total of \$49.8 million in 2022-2025 capital to fund the enhancements to  
14          the Core back-end and Customer-Facing front-end systems that are necessary to  
15          drive improvements across these key performance metrics and to enhance the  
16          overall Outage experience. The details of these system enhancements are fully  
17          described in Company Witness Hatsios’ testimony in Case Nos. U-21297 and U-  
18          21534.

19

20          In the instant case, the Company is seeking recovery of a total incremental spend  
21          of \$6.4 million in 2023-2026 EFC project capital, which consists of \$0.7 million in  
22          2023 historical and \$3.5 million in 2024 and 2025 bridge period capital for the EFC  
23          – Outage Status project shown on line 50 of Exhibit A-12, Schedule B5.7.2, and  
24          \$2.2 million in 2026 test period capital for the Outage WISMO, PPS and Map  
25          Enhancement project (\$1.7 million) shown on line 43 of Exhibit A-12, Schedule

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1 B5.7.2 and for the Operational Technology and EFC project (\$0.5 million) on line  
2 47, page 15 of Exhibit A-12, B5.4 – Distribution Plant – Technology and  
3 Automation, for ongoing enhancements to the EFC Core and Customer-Facing  
4 Systems.

5  
6 Exhibit A-24, Schedule N7 provides a complete breakdown of the incremental \$6.4  
7 million in capital, allocated across the Core and Customer-Facing Systems. This  
8 exhibit also includes the total amount of capital being invested in each system  
9 component or workstream, and the total capital that was previously approved for  
10 recovery by the Commission in Case Nos. U-21297 and U-21534. Additionally, a  
11 new tab has also been added to this exhibit since Case No. U-21534 that includes  
12 2025-2026 EFC and the Outage Experience Sustainment project costs, which are  
13 discussed in the Sustainment section of my Customer IT Project testimony.

14

15 **Q102. Since most of the total EFC capital was previously approved by the**  
16 **Commission in Case Nos. U-21297 and U-21534, what will be the focus of your**  
17 **EFC testimony in the instant case?**

18 A102. The focus of my EFC project testimony in the instant case is on fulfilling the  
19 Commission's directive in the Case No. U-21534 Final Order: "DTE Electric, in  
20 future rate cases, to provide detailed status and expenditure updates on the  
21 company's expenditures for the EFC program demonstrating the results of any  
22 investments in this program." Having provided detailed expenditure updates as  
23 previously described in Exhibit A-24, Schedule N7, the remainder of my EFC  
24 testimony will focus on providing updates to the progress made in improving key  
25 EFC metrics and the Outage experience, and ongoing opportunities for

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1 improvement that have been identified and that are being funded by the  
2 incrementally requested capital.

3

4 **Q103. How have the Company's investments in its EFC – Outage Status project**  
5 **improved the key EFC metrics and customer Outage experiences?**

6 A103. Below is a summary of the improvements in the EFC metrics and customer Outage  
7 experience realized to-date from the Company's EFC – Outage Status investments.

8

9 1. Customer Premise Power Status (PPS)

10 At the core of outage communications is the ability for the customer's meter to  
11 communicate power status to the Company. This capability not only enables the  
12 Company to communicate accurate and timely outage and restoration information,  
13 but also provides situational awareness regarding the extent of outages and the  
14 number of customers affected. This allows for a more accurate assessment of the  
15 outage and the development of more precise restoration estimates. The Company's  
16 EFC investments have improved this metric from 41% in 2023 to 52% in 2024 and  
17 it is expected to increase further to 60% in 2025 and 80% by the end of 2028.

18

19 2. Power Restoration Accuracy and Timeliness

20 Prior to the implementation of the EFC initiative, the customer's power status was  
21 tied to the job status, which was overall 94% accurate, but with a range between  
22 80% to 94% during high impact and storm days. Because the power status was not  
23 premise-based, the Company, in error, could communicate to the customer's that  
24 power was restored when, in fact, the customer was not restored. With the  
25 implementation of EFC, where the customer's power status is based on AMI meter

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1 data, the Company has consistently achieved a greater than 99% accuracy rate for  
2 outage restoration communications.

3  
4 However, timeliness of confirming the customer's power status could be delayed  
5 with the use of AMI data, so a new metric was developed to ensure timely delivery  
6 of restoration communications – Restoration Communication Sent within 1-hour.  
7 In 2023, 35% of customers with reported outages who were restored received  
8 confirmation of their restoration within 1-hour, which the Company increased to  
9 60% in 2024, with additional improvements implemented through the second half  
10 of the year, further improving week-over-week performance to 70%. The  
11 Company's long-term goal is to communicate power restoration to the Customer  
12 within 1-hour of restoration 90% of the time, with a target of 80% by end of 2025.

13

### 14 3. First Estimate Accuracy

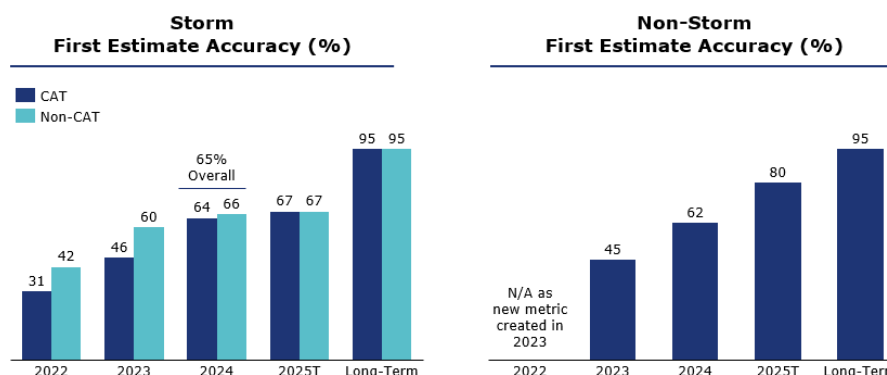
15 One of the most significant drivers of customer dissatisfaction during an outage is  
16 the lack of an accurate restoration estimate. As such, one of the key elements of the  
17 EFC project is to improve the timeliness and accuracy of the first Estimated Time  
18 of Restoration (ETR) that is delivered to customers, which measures the percent of  
19 customers that received a single and accurate estimated restoration time (ETR). The  
20 Company measures First Estimate Accuracy based on the restoration estimate  
21 information provided to customers. In non-storm conditions, customers receive a  
22 day and time estimate, while in Storm conditions customers receive a day-level  
23 estimate. During a storm, an estimate is accurate if the customer receives a single  
24 estimate communication and is restored the same day as the day provided in the  
25 estimate. The Company defines First Estimate Accuracy more stringently during a  
26 non-storm day, as the customer must receive a single estimate and be restored no

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1 earlier than 3 hours prior and no later than 30 minutes past the estimate  
2 communicated.

3  
4 As seen in Figure 13, the Company has improved its Storm First Estimate Accuracy  
5 between 2022 and 2024 by 106% for CAT from 31% to 64%, and by 57% for non-  
6 CAT from 42% to 66%. In 2024, the Company achieved an overall Storm estimate  
7 accuracy of 65%, combining both CAT and Non-CAT Storms, meeting the 65%  
8 target for 2024. For Non-Storm First Estimate Accuracy, the Company has also  
9 made improvements since the metric was established in 2023. DTE's 2024 Non-  
10 Storm performance of 62% represents a 38% improvement over the 45% achieved  
11 in 2023. Long-term, the Company is targeting 95% First Estimate Accuracy during  
12 all storms and is targeting delivery of those estimates within 4 to 6 hours of the  
13 storm weather clearing, and within 30 minutes during non-storms.

Figure 13 Improvement in First Estimate Accuracy



16  
17 In addition to the accuracy with which the Company provides customers restoration  
18 estimates, DTE has improved its estimate delivery timeliness, which is the amount  
19 of time between the weather clearing the service territory and the time outage-

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1 specific estimates are delivered to customers. Through standardization of processes  
2 and process improvements, timeliness has dramatically improved for both CAT and  
3 non-CAT Storms. In fact, during the last declared Company storm in August 2024,  
4 the Company achieved the quickest estimate delivery timeliness for a catastrophic  
5 storm, delivering estimates to customers 5 hours after the weather cleared its service  
6 territory. For non-CAT storms, the Company is delivering estimates on average  
7 within 5.5 hours after weather has cleared, and during the Company's last non-CAT  
8 storm in June 2024, restoration estimates were delivered to customers in a record 4  
9 hours after weather cleared Company service territory – which aligns with its long-  
10 term target.

11

12 4. Outage Notification Delivery

13 Historically, only 45% of customers with reported outages successfully received  
14 the expected outage status notifications, which includes confirmation of their  
15 outage, restoration estimate updates, and power restoration. However, with the  
16 Company's investments in EFC and enabled by the new notification platform  
17 implemented in 2023 and completed in 2024, this percentage has significantly  
18 increased. In 2022, the percentage rose to 70%, followed by 88% in 2023, and  
19 reached 97% in 2024. The Company has set a long-term target of achieving 99%  
20 successful delivery of outage notifications.

21

22 **Q104. What complementary opportunities has the Company identified to support**  
23 **improvements in restoration estimates and timeliness?**

24 A104. To support the Company's EFC restoration estimate and timeliness goals and  
25 objectives, DTE's data science team has developed a storm Estimated Time to  
26 Restoration (ETR) machine learning model to enhance estimate accuracy and

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1 speed. This model processes extensive historical data, such as customer outages,  
2 locations, weather, and environmental factors, without human intervention. In  
3 2024, the Company tested the model during three storms, including one CAT storm,  
4 achieving an average first estimate accuracy of 70%. To continue to improve the  
5 model's accuracy, the Company is refining the model with additional data features  
6 and aligning it with the Company's restoration priorities. In parallel, DTE's data  
7 science team is also developing a machine learning model control panel for storm  
8 leaders to manage estimate communications and handle escalations, with a  
9 minimum viable product expected this year. This control panel will implement a  
10 regulated process to verify the accuracy of the machine learning model's output  
11 before delivering estimates to customers, providing additional safeguards to ensure  
12 the reliability of the model's estimates.

13

14 **Q105. Can you provide an update on recent improvements to the Customer-Facing**  
15 **System Workstreams?**

16 A105. Yes. The Company has made improvements in the System Enhancements and  
17 Customer Channels workstreams as described below.

18 1. Police & Fire (P&F) Portal – the Company has enhanced the existing P&F  
19 portal on the DTE Website to gather additional information from customers,  
20 enabled location identification using a map pin drop, and allowed the  
21 submission of photos.

22 2. Down Power Line Reporting – the Company has enhanced the existing down  
23 wire reporting form on the DTE Website and DTE Mobile App to gather  
24 additional information from customers, allowing for more accurate trouble

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1 reporting and crew dispatch. The update also enabled reporting of four  
2 additional wire type issues, such as support wires and underground wires.

3 3. Mobile App Outage Type-ahead Feature – the Company implemented type-  
4 ahead address search in both outage and non-outage reporting in the DTE  
5 Mobile App. This update aligned the Mobile App experience with the current  
6 Web experience, allowing customers to identify their location more easily for  
7 outage reporting and outage status.

8 4. Picture Upload – the Company has enabled residential customers to include  
9 photos during outage and non-outage reporting on the DTE Website and DTE  
10 Mobile App. The goal of enabling this feature is to allow photos to be utilized  
11 by operations to assess outages and deploy the appropriate crew, improving  
12 dispatch efficiency and restoration performance. Additionally, the photos will  
13 help reduce the risk of inaccurate reports (e.g., non-DTE wire), further  
14 enhancing the overall customer experience. The Company will monitor the  
15 adoption of the feature to determine its effectiveness and assess whether it  
16 contributes to improved reporting and operational outcomes.

17 5. Status First – the Company enhanced the Web and Mobile channels to  
18 proactively notify customers when they attempt to report an outage that has  
19 already been reported or recently closed. This update aimed to reduce  
20 inaccurate or duplicate reports and provide customers with outage status more  
21 efficiently. Additionally, the enhancements enabled the immediate display of  
22 outage status for a customer's saved location, minimizing the number of clicks  
23 and steps required to access outage information.

24 6. Outage Reporting Guidance – the Company is providing enhanced outage  
25 reporting on the DTE Website and Mobile App to provide customers with



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1 information to assist in assessing trouble and reporting accurate information  
2 (e.g., common problem types / symptoms, re-report checklist).

3

4 Screenshots of these enhancements are provided in Exhibit A-24, Schedule N8.

5

6 **Q106. What does the Company have planned in 2025 for the Core and Customer-**  
7 **Facing Systems?**

8 A106. In 2025, the Company is investing \$2.9 million in 2025 bridge period capital, of  
9 which \$0.6 million was previously approved for recovery in Case No. U-21534, to  
10 make continued enhancements across the Core and Customer-Facing Systems, with  
11 the majority of the spend in the Customer-Facing workstreams. These  
12 enhancements build upon and refine the prior improvements the Company has  
13 made to the EFC processes and systems to optimize their performance, or are in  
14 response to customer learnings and feedback. DTE Electric provides a description  
15 of each of these enhancements and their customer benefits below. Specific cost  
16 breakdowns for these investments are provided on pages 1 and 2 of Exhibit A-24,  
17 Schedule N7.

18

19 **1. Restoration Estimate Windows during Storms (WISMO, Web, &**  
20 **Notifications)**

21 The Company will implement restoration estimate windows during storms to  
22 provide customers with more accurate and relevant outage status updates.  
23 Currently, customers receive day-level precision estimates during storms (e.g.,  
24 “power will be restored by end of day Thursday”). Customer research conducted at  
25 the end of 2024 identified that 87% of customers prefer estimate windows with

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1 timestamps over general time-of-day estimates and are willing to tolerate windows  
2 of up to 8 hours. These enhancements will be primarily configured within WISMO  
3 to communicate with customers with some Web enhancements.

4

5 **2. CR Call Handling Tools (WISMO, CRM)**

6 Currently, the Company's CRM channel is the only remaining channel that directly  
7 leverages status from the OMS and is not aligned with the EFC systems. To address  
8 this, the Company will be equipping Customer Representatives (CRs) with newly  
9 designed screens in the WISMO App for reporting outages and managing outage  
10 status calls. This enhancement will align the CRM System with other channels,  
11 enabling status communication based on power status. The new screens will  
12 consolidate information from WISMO, PPS, and OMS, allowing CRs to provide  
13 accurate and efficient updates to customers and will be embedded directly in CRM  
14 for easy access.

15

16 **3. Proactive Communication with AMI Single-Outage Customers (OMS,**  
17 **WISMO, Notifications)**

18 The Company will proactively communicate with single outage customers who  
19 may be experiencing an outage based on an AMI Power Outage Notification (PON)  
20 received but lacks sufficient data to confidently confirm the outage, thus requiring  
21 customer input for verification. As part of the Customer Power Status program,  
22 approximately 52% of meters report power outages. However, the AMI pre-  
23 processing process filters out false alarms before they are processed in OMS,  
24 resulting in approximately 10% of valid alarms being filtered out. While efforts  
25 continue to improve the filter's performance, the Company will also use these

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1 alarms to proactively communicate with customers to confirm outages and update  
2 the OMS system. Verified customer reports in OMS will increase with the number  
3 of customers receiving outage-related status communications. These enhancements  
4 aim to increase the accuracy of outage communications and expand the number of  
5 customers who receive these communications.

6

7 **4. Improve Communications for Cancelled Outages (OMS, WISMO,**  
8 **Notifications)**

9 Today, customers receive a generic “your report was cancelled” communication  
10 when their power line issue or hazard issue is cancelled in OMS (non-outage). This  
11 results in inaccurate customer re-reports, customer calls and poor customer  
12 satisfaction. Communication will be enhanced to include the reason for cancellation  
13 (e.g., non-DTE wire).

14

15 **5. Two-way SMS for Outage Reporting (WISMO, Notifications)**

16 Enhance existing SMS communications to allow customers to reply directly to a  
17 notification to report an outage or confirm an outage that we are proactively seeking  
18 information on (e.g., Proactive AMI Single Outage Communication mentioned  
19 above).

20

21 **6. Outage Service Recovery (OMS, WISMO, Web, Mobile)**

22 Implement service recovery initiatives for customers with long outage duration and  
23 frequent outages. The Company conducted research with customers in 2024 using  
24 a two-pronged approach. During phase 1, virtual groups were hosted to better  
25 understand customer pain points during an outage and brainstorm potential relief

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1 ideas with them, which were then shared with a broader audience in phase 2 to  
2 obtain quantitative feedback. Service recovery ideas developed that require  
3 technology to implement include providing customers outage history  
4 documentation, key tips on the Website to prevent impacts from the outage, and  
5 additional overall restoration progress (such as crew status).

6

7 **7. Outage FAQs on DTE Website (Web)**

8 Update all outage-related informational pages on the DTE website, which includes  
9 Restoration Estimate FAQs to help customers better understand the restoration  
10 process. These tools can be leveraged by customers and CRs during call handling.

11

12 **8. Improve Timeliness of Power Status Communications (PPS)**

13 Improve timeliness of restoration communications sent to the customer based on  
14 power status by ~10%. Primary improvements are driven by findings from  
15 analytics/problem solving to identify and implement technical enhancements in the  
16 PPS system.

17

18 **9. Continuous Resiliency Enhancements (WISMO, PPS, Outage Map)**

19 Enhancements will support the Company's continuous resiliency efforts to ensure  
20 systems remain online 24/7. The scope for 2025 includes implementing multi-  
21 region redundancy for EFC core systems, WISMO, PPS and Map, to provide an  
22 alternative Cloud location for when the primary Cloud region is unavailable.  
23 Additionally, the program is continually enhancing the Company's resiliency  
24 testing program to increase the breadth of systems tested and the volume of outages.

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1 **Q107. What are the expected benefits from the 2026 investment in the WISMO, PPS**  
2 **and the Outage Map and Operational Technology and EFC projects?**

3 A107. The Company is investing \$2.2 million in 2026 test period capital to fund EFC Core  
4 System and Customer-Facing System enhancements that will continue to improve  
5 the key EFC metrics and more importantly, the customer's Outage experience.  
6 Specific cost breakdowns for these investments are provided on pages 1 and 2 of  
7 Exhibit A-24, Schedule N7.

8 **1. Centralized Communications within WISMO (OMS, WISMO, Web, Mobile,**  
9 **Notifications)**

10 Enhancements include centralizing all communications within WISMO, covering  
11 planned outages, outage follow-up work, and ad-hoc communications. Analysis  
12 from NPS surveys identified that one of the primary drivers of customer  
13 dissatisfaction is the lack of communication regarding planned outages. While  
14 WISMO currently serves as the single source of truth for outage communications,  
15 some processes for planned work are not yet centralized or communicated through  
16 WISMO. This results in customers either not receiving relevant status updates, such  
17 as follow-up work scheduled or customers receiving updates through a single  
18 channel, such as ad-hoc voice communications for planned work.

19

20 **2. Enhanced Tools for Customer Representatives (CRs) (WISMO)**

21 This project will also enhance tools developed for CRs that utilize WISMO and  
22 PPS data, enabling CRs to accurately communicate outage status to customers. It  
23 ensures that CRs provide consistent information available on customer-facing  
24 channels. CRs were migrated to newly WISMO-enabled applications in 2025 that  
25 replaced outage screens in CRM, and as part of the Company's continuous

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1 improvement efforts, the team continually gathers feedback from CRs to enhance  
2 the call handling experience.

3

4 **3. Architectural Enhancements to WISMO and PPS Systems (WISMO, PPS)**

5 Enhancements will include improvements to the WISMO and PPS systems to  
6 consolidate systems, eliminating inefficiencies in maintaining two separate  
7 systems. This will optimize how AMI data is processed to reduce leaks between  
8 systems. Architectural enhancements will also support the ability for WISMO to  
9 utilize additional data from OMS, such as Supervisory Control and Data  
10 Acquisition System (SCADA) and Bellwether Meters, to communicate outage  
11 status to the customer. As the Company continues to improve the use of data in  
12 OMS to more accurately create and model outage jobs, WISMO will need to be  
13 enhanced to be able to leverage the benefits of the improvements of OMS.

14

15 **4. Continuous Resiliency Enhancements (Outage Map)**

16 Enhancements will support the Company's continuous resiliency efforts to ensure  
17 systems remain online 24/7, focusing on a disaster recovery plan for the Outage  
18 Map. See Exhibit A-24, Schedule N3 line 408 for additional project details.

19

20 The EFC – Outage Status project and the Company's commitment to achieving the  
21 long-term targets set for the four key EFC metrics demonstrates that it is prudently  
22 making investments to significantly improve the customer Outage experience.  
23 Ongoing EFC updates will be provided at the bi-annual meetings with the MPSC  
24 Staff.

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1           3)       Customer Closed Loop Development

2           The Company invested \$1.0 million in historical year spend for the Customer  
3           Closed Loop Development project as shown on Line 47 of Exhibit A-12, Schedule  
4           B5.7.2. to complete the Billing and Payments Closed Loop Notifications. This  
5           capital reflects a variance of \$0.5 million less spend than what was approved for  
6           cost recovery in Case No. U-21534. The variance is due to a reduction in the costs  
7           to configure closed-loop customer notifications, which were no longer required  
8           because the configuration was encompassed in the scope of what was needed for  
9           the Error Free Communication project. See Exhibit A-24 Schedule N3, line 416 for  
10          additional project details.

11

12                   *d) Payment Merchant Fee Project*

13       **Q108. Why is the Company investing and seeking recovery of \$10 million in 2025 for**  
14       **the Payment Merchant Fee project?**

15       A108. As described in Company Witness Foley's testimony, in its final orders in Case No.  
16       U-21291 (DTE Gas) and Case No. U-21534 (DTE Electric) rate cases, the  
17       Commission denied recovery of the Company's projected 2025 non-residential  
18       credit / debit card merchant fee expense, while indicating that should residential  
19       merchant fees be contested in a future rate case, they would apply the same  
20       reasoning for disallowance: "it is not reasonable or prudent to socialize over the  
21       utility's customer base the merchant fees for customers who choose to pay by credit  
22       card."<sup>4</sup>

---

<sup>4</sup> Case No. U-21534 Order at 232-233; Case No. U-21291 Order at 158.

Line  
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1 The disallowance of non-residential merchant fees, and the potential for a future  
2 disallowance of residential merchant fees, is of concern to the Company as it would  
3 make accepting credit and debit card payments cost-prohibitive for its customers.  
4 And although there is nothing in the MPSC Billing Rules that requires a gas or  
5 electric utility to accept credit or debit card payments, the Company recognizes the  
6 convenience and value of card usage for a significant number of its customers and  
7 seeks to ensure that these customers continue to have the option of making card  
8 payments.

9 The Company therefore is investing \$10 million in capital in 2025 bridge period  
10 capital, as shown on line 53 of Exhibit A-12, Schedule B5.7.2, to transition to a  
11 system that allows for the charging of a fee / surcharge for card usage as a  
12 reasonable and prudent solution that will allow non-residential customers who  
13 choose to use a credit or debit card the ability to continue to do so without  
14 financially burdening those non-residential customers who choose to not use a  
15 credit or debit card. This approach is consistent with 80% of utilities that charge  
16 non-residential customers a card fee / surcharge. Although in the instant case,  
17 through the testimony of Company Witness Foley, the Company is proposing the  
18 continued recovery of residential merchant fees through base rates, the new  
19 payment system and associated enhancements will have the flexibility to charge a  
20 fee / surcharge for residential customer card usage if this proposal for recovery is  
21 denied. See Exhibit A-24, Schedule N3, line 425 for additional project details.

22

23 **Q109. What is the scope of work funded by the \$10 million in capital being allocated**  
24 **to the Payment Merchant Fee project?**



Line  
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1 A109. The \$10 million in capital will be used to fund the use of a third-party consumer  
2 payment provider - Paymentus, Speedpay, BillMatrix, or Kubra – to develop the  
3 Company's card fee / surcharge solution across all served and self-service channels.  
4 The provider will develop a solution that handles credit card fee processing, offers  
5 Visa consulting support, and assists with the development of a long-term payment  
6 strategy that will ensure seamless bill payment options for customers. Currently, all  
7 utility companies that charge credit card fees use one of these third-party providers.  
8 See Exhibit A-24, Schedule N3, line 424 for additional project details.

9

10 **Q110. Did the Company consider alternatives to the use of a third-party consumer**  
11 **payment provider?**

12 A110. Yes. In addition to assessing the impact to customers of simply discontinuing the  
13 use of card payments, which would negatively impact the 1.4 million customers  
14 who in 2024 made at least one credit or debit card payment, the Company assessed  
15 the scope of work, benefits, and risks of modifying its existing internal payment  
16 platform to charge and process credit and debit card fees / surcharges, and  
17 determined the best solution would be to leverage a third-party provider.

18

19 **Q111. Why did the Company determine that a third-party solution would be a better**  
20 **option than using its own internal payment platform?**

21 A111. Leveraging a third-party consumer payment solution provides DTE with greater  
22 flexibility, reduced risk, enhanced customer experience, and access to advanced  
23 features—all while ensuring adherence to industry standards. These benefits  
24 significantly outweigh the effort and resources required to update and maintain an

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1 existing home-built payment system, positioning the Company for long-term  
2 success and innovation. The benefits of a third-party payment provider include:

3

4 1. Flexible Fee Structure Support

5 Utilizing a third-party consumer payment solution enables DTE to establish a  
6 flexible and scalable fee structure, incorporating both flat fees and percentage-  
7 based fees. While DTE's current payment platform is predominantly home-built,  
8 the Company leverages Paymetric, a Worldpay company, to process payments and  
9 manage PCI-sensitive data. However, Paymetric does not support flat fee  
10 implementations, which limits flexibility in the fee structure.

11 2. Reduced Financial Risk

12 Third-party payment providers assume the responsibility for financial risk, ensuring  
13 that fees collected are sufficient to cover merchant fees and other associated costs.  
14 This approach minimizes the financial exposure for DTE, alleviating concerns  
15 around fee recovery and potential losses.

16

17 3. Additional Out-of-the-Box Benefits

18 Third-party solutions provide immediate access to advanced features that can be  
19 seamlessly integrated shortly after the Payment Merchant Fee project. These  
20 features often require minimal investment and effort but yield significant benefits  
21 and include enhanced system resiliency (enabling payment processing during back-  
22 end system outages), expanded payment method options (such as Venmo, PayPal,  
23 etc.), and improved overall payment functionality.

24

25 4. Continuous Innovation and Technological Advancements

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1 Leading third-party payment platforms continuously evolve by integrating  
2 emerging technologies such as AI-driven fraud prevention, mobile wallet  
3 integration, and instant payments. These advanced features help improve  
4 transaction security, streamline payment options, and enhance customer  
5 experience. Maintaining this level of innovation within an internal solution would  
6 require significant investment in research, development, and ongoing upgrades,  
7 which could be costly and resource-intensive.

8

9 5. Access to Specialized Expertise

10 Third-party payment providers offer continuous support and specialized expertise,  
11 helping DTE remain aligned with evolving regulations, industry standards, and  
12 emerging market trends. This ensures compliance with dynamic rules, such as  
13 changing Visa requirements, and enables the Company to adapt quickly to new  
14 payment innovations.

15

16 6. Industry-Standard Practices

17 Most utility companies rely on third-party payment solutions for their transaction  
18 processing needs. This widespread industry adoption of third-party solutions  
19 underscores their reliability, security, and scalability, positioning DTE in line with  
20 industry best practices.

21

22 **Q112. When does the Company expect to begin charging customers who choose to**  
23 **use a debit or credit card a fee / surcharge?**

24 A112. The Payment Merchant Fees project is estimated to take 10-12 months to complete  
25 (i.e., design, development, testing). The Company expects to begin charging non-

Line  
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1 residential customers who choose to make card payments a fee / surcharge by the  
2 end of the first quarter of the 2026 test period. The implementation of a residential  
3 customer fee / surcharge will be dependent on the outcome of the Commission's  
4 final order in the instant case, which would be expected sometime in February of  
5 2026. Company Witness Foley's testimony provides for consideration of two  
6 potential paths forward in the event the Commission denies the Company's request  
7 for on-going recovery of residential merchant fees.

8

9 **Q113. What card fee / surcharge structure is being proposed and how will the**  
10 **Company manage merchant fees ahead of the planned 2026 Payment**  
11 **Merchant Fees project implementation?**

12 A113. These details can be found in Company Witness Foley's direct testimony, in which  
13 he provides additional detail regarding customer card usage and the amount of  
14 merchant fee expense for which the Company will continue to seek recovery in the  
15 instant case.

16

17 **E. Projects < \$250K**

18 **Q114. What is included in the "Projects less than \$250,000" category?**

19 A114. The workpaper titled "IT Projects <\$250K" shows spend for projects in IT with  
20 estimated spend less than \$0.25 million in the projected bridge and test periods. The  
21 investments in these projects occurred in 2023, and the Company has implemented  
22 the projects. These projects span the Portfolios and are necessary investments to  
23 collectively support DTE.

Line  
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1 **VII. Historical Spend Variance**

2 **A. 2023 Spend Variance**

3 **Q115. How do the Company's 2023 expenditures on total IT capital projects compare**  
4 **to the amount authorized for inclusion in rates in Case No. U-21534?**

5 A115. The Company spent \$174.6 million of capital on IT projects in 2023, which is \$26.1  
6 million more than the \$148.5 million approved by the Commission in Case No. U-  
7 21534, as shown in line 21 of Exhibit A-24, Schedule N2.

8

9 Additionally, it must be noted that there is a \$(2.8) million variance than compared  
10 to the amounts reflected in Exhibit AG-15 in Case No. U-21534 [AGDE-3.122, Ex  
11 A-12, Schedule B5.7 2018-2023 Actuals] due to post-period adjustments and write-  
12 offs.

13

14 **Q116. Where are the reasons for the variance between the 2023 actual capital spend**  
15 **versus the spend authorized in Case No. U-21534?**

16 A116. Exhibit A-24, Schedule N2, labeled as 2023 Historical Spend Variance Recovery,  
17 shows the comparison for projects greater than \$0.5 million with a variance  
18 exceeding 20% and where additional recovery is being sought, as indicated in Table  
19 9. Additionally, the total for Level 3 project disallowance in Case No. U-21534 is  
20 \$11.3 million, of which \$9.3 million pertains to under-recovered projects. The  
21 variance in these projects is discussed in Section VI of my testimony. Table 9 below  
22 shows a list of projects that the Company is seeking additional recovery for in 2023  
23 and are also included in Exhibit A-24, Schedule N2.

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1

**Table 9      Variance Exhibit/Schedule Reference by Project**

| <b>Portfolio</b>                | <b>Description</b>                                             | <b>Variance Testimony Reference</b> |
|---------------------------------|----------------------------------------------------------------|-------------------------------------|
| Plant and Field                 | Network Reliability and Monitoring                             | SBA - 125-126                       |
| Plant and Field                 | Production Growth                                              | SBA – 127                           |
| Plant and Field                 | Maximo Platform Program                                        | SBA - 138-139                       |
| Infrastructure Operations       | Wide Area Network and Wireless Local Area Network Expansion    | SBA – 76-77                         |
| Infrastructure Operations       | DTE Private Cloud Infrastructure as a Service                  | SBA – 84-85                         |
| Infrastructure Operations       | Server Engineering Support Services                            | SBA – 60                            |
| Information Technology for IT   | IT Service Management Tool                                     | SBA – 34-35                         |
| Information Technology for IT   | IT for IT Application Health                                   | SBA – 33-34                         |
| Information Protection Security | Automated Provisioning                                         | SBA – 46-47                         |
| Enterprise Data Analytics       | Advance and Enhance the Enterprise Data Platform               | SBA – 88-89                         |
| Customer Service                | Customer Information Technology (CIT) Configuration Management | SBA – 161-162                       |
| Corporate Applications          | Enterprise Automation                                          | SBA – 106-109                       |
| Innovation                      | Applied Innovation                                             | SBA – 91-92                         |
| All                             | 10% disallowance - Level 3 under recovered projects            | Various                             |

Line  
No.1 **B. Other Variance**

2 **Q117. Were there any other projects that had variances that you have not yet**  
 3 **discussed?**

4 A117. Yes. The projects listed in Table 10 below were not completed in 2023 or 2024 and  
 5 are not planned to be completed in 2025, as previously approved and included in  
 6 rates in Case No. U-21534.

7

8

**Table 10 Project Variance Reasons**

| <b>Project</b>                                    | <b>Reason for Variance</b>                                                                                                                                                                                                                      |
|---------------------------------------------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Vendor Onboarding for DTE                         | As part of the Annual Planning and Prioritization Process enhancement, all investments underwent a thorough reassessment. Following diligent reviews, the Vendor Onboarding for DTE capital investment has been deferred to a future year.      |
| Network Access Control                            | This project has been suspended and the scope has been integrated into the Network segmentation Phase (2+) project. Variance is discussed in Ambrose's direct testimony pages 79,80                                                             |
| Mobile Device Management (MDM)                    | Due to the dependency project Enterprise Mobility Management (EMM) had technical issues causing this project to pause                                                                                                                           |
| Source to Pay(S2P) Transformation                 | The scope of the project was re-evaluated, and through successful vendor negotiations, the company secured extended support until 2027.                                                                                                         |
| SAP Employee Central Payroll                      | It was determined that SAP Employee Central Payroll should be implemented with the Time Entry project for an efficient integration, testing capabilities, and deployments. Hence, it was resolved to defer the project's implementation to 2026 |
| Talent System Optimization                        | 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.                                                            |
| GenOpts-FERC Order 841 Compliance                 | This project has been postponed to future years due to insufficient customer participation in Electric Storage Resources (ESR). DTE will continue using the manual process until customer volume increases.                                     |
| Integrated Information Resource (I2R) Replacement | The project scope has been integrated into the Maximo Engineering Process Automation project. Maximo Engineering Process Automation variance is discussed in the Ambrose's Direct Testimony Page 143                                            |

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| Project                                   | Reason for Variance                                                                                                                                                                  |
|-------------------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Customer Notifications<br>TCPA Compliance | This project is currently being replaced by the Customer Consent and Preference Management project on line 1 of Exhibit A-12, Schedule B5.7.2.                                       |
| MDM Stabilization                         | 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. |
| Never Billed Accounts due to Theft/Fraud  | 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. |

1

2 **Q118. Are there any common causes in variance from Case No. U-21534?**

3 A118. Yes. At times, the IT Department needs to adjust the scope or schedule of projects  
4 to address high-priority items based on emerging and higher priority needs. My  
5 explanations of historical spend and changes between investment years provided in  
6 the preceding sections reflect this prioritization. The re-sequencing of the scope of  
7 an entire project reflects the operational reality of making investments with finite  
8 IT resources, and as the Company continues to improve its processes and address  
9 the key IT investment drivers of cybersecurity, reliability and resiliency, and  
10 affordability (cost effectiveness).

11

12 **Q119. Does this complete your direct testimony?**

13 A119. 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-21860

## QUALIFICATIONS

AND

## DIRECT TESTIMONY

OF

NEAL T. FOLEY

**DTE ELECTRIC COMPANY**  
**QUALIFICATIONS AND DIRECT TESTIMONY OF NEAL T. FOLEY**

Line  
No.

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

2   A1.   My name is Neal Foley. My business address is: One Energy Plaza, Detroit,  
3       Michigan 48226. I am employed by DTE Electric Company (“DTE Electric” or  
4       “Company”).

5

6   **Q2.   On whose behalf are you testifying?**

7   A2.   I am testifying on behalf of DTE Electric.

8

9   **Q3.   What is your educational background?**

10   A3.   I received a Bachelor of Science in Aerospace Engineering and a Bachelor of  
11       Science in Mechanical Engineering from the University of Michigan. I also  
12       received a Master of Science in Systems Engineering from Johns Hopkins  
13       University and a Master of Business Administration from Georgetown University.

14

15   **Q4.   Please summarize your professional experience.**

16   A4.   In 2007 I was employed by Lockheed Martin Corporation as a Satellite Operations  
17       Engineer. In 2008, I was hired by Booz Allen Hamilton as an Associate Consultant  
18       in its Federal consulting practice. In 2012, I was hired by Deloitte as a Manager of  
19       Financial Analysis in its Federal consulting practice. In 2014, I was hired by  
20       McKinsey & Company as an Associate Consultant, ultimately being promoted to  
21       Engagement Manager before my departure in 2017. In 2017 I was hired by DTE  
22       Energy Company as Manager of Corporate Strategy. In this role I was broadly  
23       responsible for tracking and assessing utility industry trends, executing analyses to  
24       better understand the economic impacts of emerging technologies and business  
25       models, and leading strategic initiatives for the Company. In December 2020 I was

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1 promoted to Director of Regulatory Affairs where I was responsible for the  
2 management of regulatory activities related to DTE Electric's Load Research,  
3 Tariffs, Pricing, and Rate Design. In December 2024, I started my current role as  
4 Director of Electric Marketing in the Electric Sales and Marketing organization of  
5 DTE Electric.

6

7 **Q5. What are your current duties and responsibilities?**

8 A5. My responsibilities as Director of Electric Marketing span three primary focus  
9 areas:

- 10 1. Transportation Electrification: support and accelerate Electric Vehicle ("EV")  
11 adoption within DTE Electric's service territory;  
12 2. New Product Development: assess and provide products and services, which  
13 support customer satisfaction and customer affordability, including under the  
14 Value-Added Programs and Services ("VAPS") regulations;  
15 3. Customer Marketing: communicate with customers regarding DTE Electric  
16 rates and tariffs for electric service and address customer inquiries or  
17 complaints.

18

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

21 A6. Yes. I have sponsored testimony and exhibits before the MPSC in the following  
22 DTE Electric cases:

| <u>Case No.</u> | <u>Description</u>                             |
|-----------------|------------------------------------------------|
| 24 U-20836      | DTE 2022 Electric Rate Case                    |
| 25 U-21376      | DTE 2023 Distributed Generation Tariff Options |

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No.

|   |         |                             |
|---|---------|-----------------------------|
| 1 | U-21297 | DTE 2023 Electric Rate Case |
| 2 | U-21534 | DTE 2024 Electric Rate Case |

Line  
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1 **Purpose of Testimony**

2 **Q7. What is the purpose of your testimony?**

3 A7. The purpose of my testimony is to describe and support the programs, policies, and  
4 any associated costs for the four following areas:

- 5 1. Execution of the Company's Transportation Electrification Plan ("TEP");  
6 2. Merchant Fees;  
7 3. Full Time of Day ("TOD") Rollout Customer Outreach Expenses; and,  
8 4. Electric Regulated Marketing operations and maintenance ("O&M")  
9 expenses.

10

11 **Q8. Are you sponsoring any exhibits in this proceeding?**

12 A8. Yes. I am sponsoring the following exhibits:

| 13 | <u>Exhibit</u> | <u>Schedule</u> | <u>Description</u>                                  |
|----|----------------|-----------------|-----------------------------------------------------|
| 14 | A-12           | B5.4            | Projected Capital Expenditures Distribution Plant – |
| 15 |                |                 | Connections, Relocations and Other                  |
| 16 | A-12           | B5.9            | Charging Forward & Transportation Electrification   |
| 17 |                |                 | Plan Cost Projections                               |
| 18 | A-13           | C5.7.1          | Customer Service– Credit/Debit Card Merchant Fees   |
| 19 | A-13           | C5.9            | Regulated Marketing Projected O&M Expenses          |
| 20 | A-13           | C5.9.2          | TOD Regulatory Asset Deferral                       |
| 21 | A-29           | S1              | DTE's Filed TEP                                     |

22

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

24 A9. Exhibit A-29, Schedule S1 was prepared prior to me transitioning into my current  
25 role at the Company, although I am sponsoring it as part of my testimony in the

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1 instant case. Exhibit A-12, Schedule B5.4, Page 4 is co-sponsored with Company  
2 Witness Hill. Exhibit A-13, Schedule C5.9.2 is co-sponsored with Company  
3 Witness Sparks. The remaining exhibits were prepared under my direction in  
4 support of the instant case.

5

6 **Transportation Electrification Plan (TEP) – Overview and Previous Guidance**

7 **Q10. What are the overarching goals and guiding principles of the Company’s**  
8 **TEP?**

9 A10. The Company's TEP was originally submitted in Case No. U-21538 and  
10 subsequently presented in Case No. U-21534 (the Company’s most recent electric  
11 rate case) for approval. It is included in the instant case as Exhibit A-29, Schedule  
12 S1.

13

14 Through the execution of its TEP, the Company aims to enable a cleaner energy  
15 future for its customers through transportation electrification by:

- 16 • Accelerating customers’ journeys to EV adoption through programming  
17 that includes enhancing the state’s charging network, beneficial electric  
18 pricing options, and advisory services;
- 19 • Amplifying EV benefits and breaking down barriers for all the communities  
20 it serves, with an intentional focus on low-income (“LI”) customers and  
21 disadvantaged communities (“DACs”);
- 22 • Intelligently integrating EV load with the grid of the future by using  
23 advanced technologies to reduce peak demand and minimize costs to all  
24 customers; and

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- 1           • Striving to deliver reliable, cleaner energy to power EVs and reduce state-  
2           wide carbon emissions.

3           To achieve these goals, the Company developed its TEP with the following guiding  
4           principles in mind:

- 5           • Support and accelerate EV adoption by facilitating charger deployment  
6           while maintaining affordability benefits for all the Company's customers at  
7           the portfolio level;  
8           • Consider unique reasons for utility participation such as closing charging  
9           gaps and improving economics of electrification in the near-term; and  
10          • Promote equity with a focus on low-income customers and disadvantaged  
11          communities.

12

13           The Company's TEP aligns with the MI Healthy Climate Plan<sup>1</sup> and the supporting  
14           MI Future Mobility Plan<sup>2</sup>, which aim to deploy 100 thousand public EV chargers  
15           to support two million EVs in the state by 2030.

16

17   **Q11. When does the Company plan to update and publish a new version of the TEP?**

18   A11. In its January 23, 2025, Order in Case No. U-21492 the Commission established  
19       updated TEP filing requirements. This included a requirement for Michigan utilities  
20       to submit TEPs by July 1, 2025, and at least every two years thereafter. The Order  
21       noted that the Company had filed a TEP in 2024 and therefore required it to file an  
22       updated TEP by July 1, 2026. The Company plans to comply with this guidance  
23       and file an updated TEP by that date.

---

<sup>1</sup> MI Healthy Climate Plan available at <https://www.michigan.gov/egle/about/organization/climate-and-energy/mi-healthy-climate-plan>, April 2022

<sup>2</sup> MI Future Mobility Plan available at [state-strategy-for-the-future-of-mobility-and-electrification-detailed-version.pdf](https://www.michigan.gov/egle/about/organization/climate-and-energy/mi-future-mobility-plan), November 2022

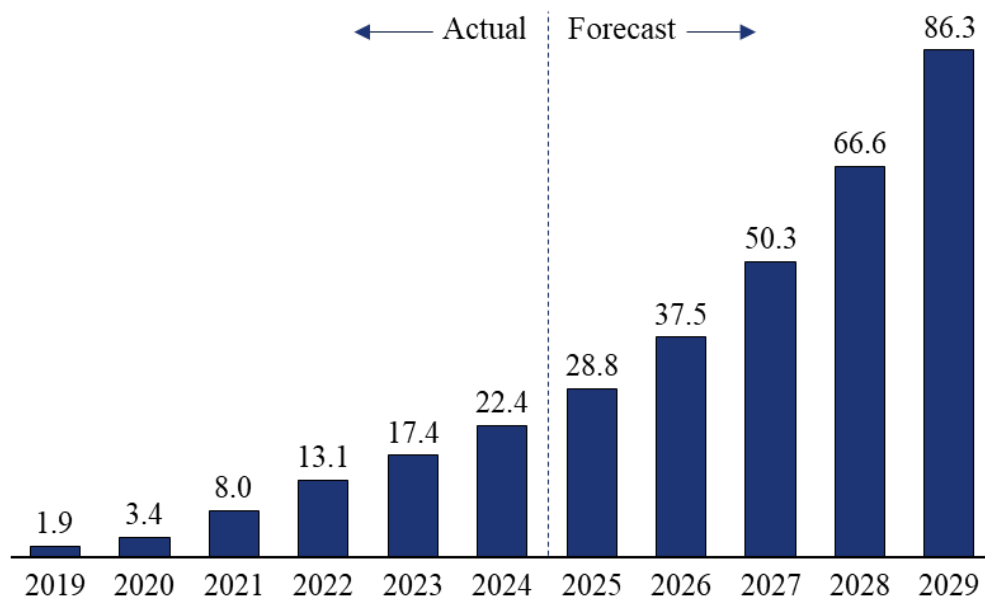
Line  
No.

1 **Q12. What is the Company's latest forecast for EV adoption in its service territory?**

2 A12. Company Witness Leuker sponsors the Company's EV adoption forecast. As  
3 described by Company Witness Leuker, EV sales in the Company's service  
4 territory have grown at a compound annual growth rate (CAGR) of 74% between  
5 2019 and 2023, with approximately 17,400 new EVs registered in 2023, compared  
6 to about 1,900 EVs in 2019. The Company's forecast for new EV registrations in  
7 its service territory is shown below in Figure 1.

8

9 **Figure 1 Actual/forecasted annual new EV registrations in the**  
10 **Company's service territory; 2019-2029 (thousands)**

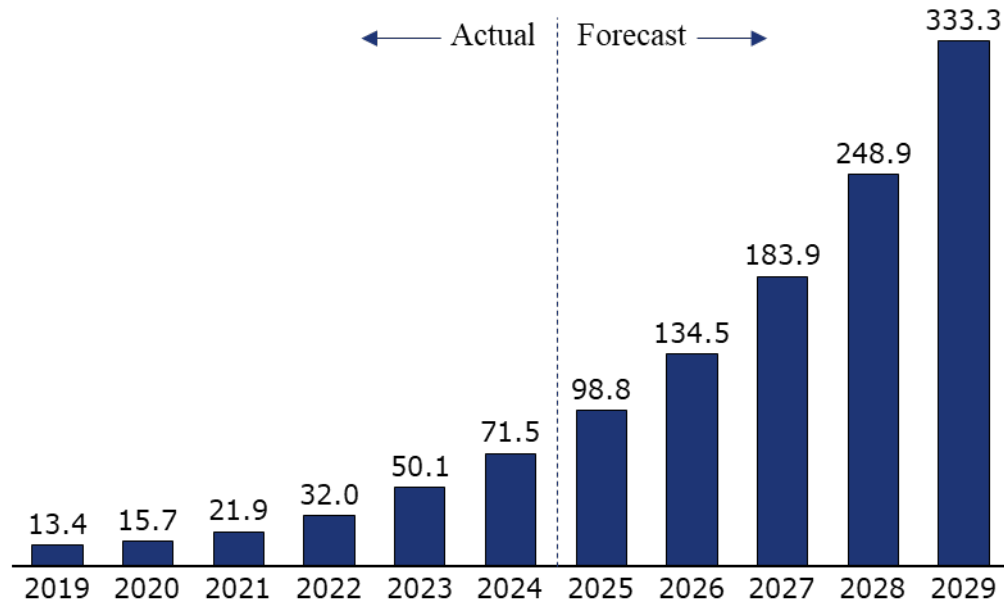


11

12 Given the level of adoption the Company is forecasting, it expects the total number  
13 of EVs in its service territory to grow to over 330 thousand by 2029. The  
14 Company's forecast for total EV registrations in its service territory is shown below  
15 in Figure 2.



**Figure 2 Actual/forecasted total EV adoption in the Company's service territory; 2019-2029 (thousands)**



4     **Q13. Can you summarize the Company's proposals related to the Company's TEP**  
5     **and other EV programming in the instant case?**

A13. Yes. In Case No. U-21534 (the Company’s most recent electric rate case), the Company proposed to formally transition away from its legacy Charging Forward program and begin execution of its TEP starting in 2025. In its January 23, 2025 Order in that Case (“January 2025 Order”), the Commission approved the Company’s proposed TEP, with the following adjustments:

- 11 • Reallocate any unused funding from the Business Charger Rebate program  
12 to Non-DAC/Rural On-Route Charger Rebates (January 2025 Order; page  
13 326)
- 14 • Offer rebates for Public L2 Chargers (January 2025 Order; page 327); while  
15 the January 2025 Order specifically identified “workplaces and shopping  
16 areas” as qualifying for such a rebate, the Company has interpreted the

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1 Commission's order to apply to all Public L2 Chargers since MEIU's  
2 proposal (which the Commission adopted) more broadly referred to "public  
3 Level 2 chargers."<sup>3</sup>

- 4 • Allow self-attestation of customer interest for parties requesting a Multi-Unit  
5 Dwellings (MUDs) Charger Rebate (January 2025 Order; page 334)
- 6 • Investigate and analyze whether it would be beneficial to offer a charger  
7 output capacity tier-based School Bus Charger Rebates to schools that do  
8 not utilize bi-directional chargers (January 2025 Order; page 338)

9

10 At a high level, the Company's proposal in the instant case is to continue to execute  
11 on its TEP, including the adjustments ordered by the Commission in its January  
12 2025 Order. The Company further seeks to confirm that it has authorization to issue  
13 rebates beyond the forward test year in this case and that it can reallocate funding  
14 between rebate programs as necessary to accommodate prevailing adoption trends.

15

16 In addition, the Company is proposing the continuation of its Charging Hubs Pilot.  
17 While this pilot is not specifically discussed within the TEP, it is a program that  
18 was approved by the Commission in its November 18, 2022 Order in Case No. U-  
19 20836 ("November 2022 Order") and warrants continuation.

20

21 I provide specifics of the Company's proposals later in my testimony.

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<sup>3</sup> Case No. U-21534; Direct Testimony of Dr. Laura S. Sherman (pages 46-47)

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1 Notably, the Company is also proposing to extend its managed charging pilot,  
2 known as the “Smart Charge” pilot. Company Witness Leuker is sponsoring this  
3 proposal as part of the Company’s Demand Response (DR) portfolio.  
4

5 **Q14. Has the Commission provided any other guidance related to the Company’s**  
6 **EV-related programming and offerings?**

7 A14. Yes. In its January 2025 Order the Commission ordered that the Company propose  
8 in its next general rate case a one-time CIAC waiver for new residential customer  
9 load, which would also include new installations of EV charging equipment that  
10 complies with specific voltage requirements (January 2025 Order; page 344).  
11 Company Witness Willis responds to this guidance and sponsors a proposal for a  
12 residential CIAC waiver in his testimony.  
13

14 The Commission further recommended that Staff convene interested persons to  
15 determine the next steps for Level 1 and Level 2 commercial EV charging CIAC  
16 waivers (January 2025 Order; page 344-345). At the time of filing, Staff has not yet  
17 convened interested persons on this topic.  
18

19 As it relates to EV charger rate design, the Commission extended the DCFC  
20 demand charge holiday by two years, through June 2028. It directed the Company  
21 to collaborate with Staff and interested persons to develop an optional EV fast  
22 charger rate, as a successor to Rate Schedule D3, and file for approval of such a  
23 rate no later than December 1, 2026. (January 2025 Order, page 426). The Company  
24 has not included a proposed optional successor EV fast charger rate in this case but  
25 anticipates doing so prior to December 1, 2026.

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1 As it relates to the Company’s TEP Benefit Cost Analysis (BCA), the Commission  
2 found “that DTE Electric’s proposed TEP portfolio-level BCA is reasonable and  
3 prudent and should be approved.” However, the Commission noted that an open-  
4 source BCA tool was being developed through Case No. U-20898 (January 2025  
5 Order; pages 354-356). The Company is participating in Case No. U-20898 and  
6 anticipates utilizing the open-source BCA tool in future iterations of its TEP once  
7 it becomes available. As such, the Company has not updated its TEP BCA since it  
8 was originally presented in Case No. U-21538 and Case No. U-21534.

9  
10 Additionally, the Commission found that “Staff’s proposal for DTE Electric to  
11 provide in its next general rate case a list of the federal programs for EVs for which  
12 the company has applied and received funds to be reasonable and that it should be  
13 approved” (January 2025 Order; page 314). A discussion of Federal Grants is  
14 included later in my testimony.

15  
16 Finally, in its January 2025 Order the Commission provided various guidance on  
17 items the Company should include in its TEP Annual Status Reports. As discussed  
18 previously, the Company also notes that the Commission established updated TEP  
19 filing requirements through its January 23, 2025, Order in Case No. U-21492. The  
20 Company plans to provide all required data outlined in both the January 2025 Order  
21 and the updated TEP filing requirements in its TEP Annual Status Reports. In  
22 alignment with the updated TEP filing requirements, the Company plans to submit  
23 its next TEP Annual Status Report by June 1, 2026, which will cover Calendar Year  
24 2025.

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1   **Q15. What federal programs for EVs has the Company applied for and what was**  
2       **the outcome of those applications?**

3   A15. The Company has applied for three federal grants to support two sites as part of its  
4       Charging Hubs pilot. First, in February 2023 the Company applied for the  
5       Department of Transportation's (DOT's) Rebuilding American Infrastructure with  
6       Sustainability and Equity (RAISE) grant program in partnership with Detroit Diesel  
7       (Daimler Truck North America) and the State of Michigan. It was awarded \$8.5  
8       million in July 2023 to support the buildout of the first Charging Hub in Redford.  
9       This site is further discussed later in my testimony.

10

11       Second, in April 2023 the Company applied for the Department of Energy's  
12       (DOE's) Grid Resilience and Innovation Partnerships (GRIP) grant to fund  
13       resilience and innovation, proposing to build a second Charging Hub in Southeast  
14       Detroit to serve the I-75 and I-94 corridors near the Ambassador Bridge. The  
15       Company's application was rejected in the third quarter of 2023.

16

17       Third, in October 2024 the Company submitted a concept paper with the Energy  
18       Efficiency and Renewable Energy (EERE) Vehicle Technologies Office (VTO) to  
19       develop innovative EV Charging infrastructure as part of a second Charging Hub  
20       near key locations such as the border with Canada. This was followed by the  
21       Company submitting a full application in November 2024. The Company's  
22       application was rejected in January 2025.

23

24       In addition to directly applying for the federal grants listed above, the Company has  
25       assisted its customers in accessing state and federal funds in the following ways:

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- 1           • Since 2022 the Company has supported school districts in its service  
2           territory in securing available federal Bipartisan Infrastructure Law funding  
3           through the Environmental Protection Agency’s (EPA’s) Clean School Bus  
4           (CSB) Rebate program. More specifically, the Company proactively  
5           reached out to over 160 schools and assisted them with the grant application  
6           process. Ultimately, the Company helped school districts apply for over 250  
7           electric school buses resulting in 142 buses being awarded, totaling  
8           approximately \$49 million in funding through the third round of CSB  
9           funding.
- 10          • The Company has assisted customers in its service territory in qualifying  
11          for Michigan Department of Transportation’s (MDOT’s) National Electric  
12          Vehicle Infrastructure (NEVI) program funding by providing “will serve”  
13          utility letters to 41 prospects that submitted bids to the first round of  
14          MDOT’s RFP resulting in six nodes being awarded funding. For the second  
15          round of NEVI funding, the Company provided more than 50 “will serve”  
16          utility letters, although the future of the NEVI program is uncertain due to  
17          the “Unleashing American Energy” Executive Order issued by President  
18          Donald Trump on January 20, 2025.
- 19          • The Company supported its customers applying for the Charging and  
20          Fueling Infrastructure (CFI) Discretionary Grant Programs, such as  
21          Corridor Charging and Community Charging. The Company supported two  
22          cities with their applications for Community Charging grants to expand  
23          equitable access to EV charging stations among communities and provided  
24          a letter of support for the State of Michigan’s CFI application. Through  
25          these programs, the City of Detroit was awarded roughly \$23 million to

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1 build the city’s charging infrastructure, and the City of Ann Arbor received  
2 roughly \$2.8 million to expand public EV charging access. For the second  
3 round of CFI awards, the City of Detroit has been awarded \$15 million for  
4 curbside and multifamily charging.

- 5 • The Company supported Wayne County’s Energy Efficiency and  
6 Conservation Block Grant voucher program to convert their fleet of vehicles  
7 to EVs, resulting in a \$487,000 award in 2024 to convert 6-8 vehicles to  
8 electric and install the necessary charging infrastructure.

9  
10 **Q16. What are the major elements of the Company’s proposed EV programming?**

11 A16. As largely captured in the Company’s TEP (Exhibit A-29, Schedule S1), the major  
12 elements of the Company’s EV programming are:

- 13 • Residential Customer Rebates targeting Low Income (LI) Single-Family  
14 Homes (SFHs);
- 15 • Business Charger Rebates targeting Multi-Unit Dwellings (MUDs), on-route  
16 DC Fast Chargers (DCFCs), and Public Level 2 (L2) Chargers<sup>4</sup>;
- 17 • Fleet Charger Rebates targeting transit bus DCFCs, School bus DCFCs, all  
18 other fleet DCFCs, and L2 fleet chargers;
- 19 • Education and Outreach (E&O) including, for example, informational  
20 residential and business websites, in-person EV “ride and drive”  
21 experiences, and eFleet Advisory Services;
- 22 • Emerging Technology Fund enabling the timely funding of prudent pilots;
- 23 • TEP IT Capabilities; and
- 24 • Program Administration to maintain a permanent EV team

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<sup>4</sup> Public L2 Chargers Rebates were not originally included in the Company’s TEP, but were ordered to be offered in the Commission’s January 2025 Order

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1 In addition to the TEP elements listed above, the Company is also proposing  
2 recovery of investment related to its Charging Hubs Pilot originally approved by  
3 the Commission in its November 2022 Order.

4

5 **Q17. What cost treatment is applied to each EV programming element?**

6 A17. Consistent with the Commission's January 2025 Order:

- 7 • All rebate program (i.e., residential, business, and fleet) and Emerging  
8 Technology Fund costs are deferred as a Regulatory Asset;  
9 • The Charging Hubs Pilot and TEP IT Capabilities costs are capital  
10 expenditures; and  
11 • E&O and Program Administration costs are O&M

12

13 **Q18. How has the Company accounted for utility make-ready costs to support its**  
14 **projected level of EV adoption?**

15 A18. The Company estimates that approximately \$98 million of non-Contribution in Aid  
16 of Construction (CIAC) utility make-ready investment will be needed between  
17 2025 and 2028 to support the forecasted level of EV adoption. This is based on  
18 estimates that the Company will be responsible for approximately 85% of the  
19 investment work under the line extension policy when customers request new or  
20 upgraded service connection to install chargers, even if they don't participate in a  
21 rebate-paying TEP program.

22

23 The bridge year (i.e., 2025) portion of this investment of \$9.2 million and test year  
24 (i.e., 2026) portion of this investment of \$18.6 million are included in Exhibit A-  
25 12, Schedule B5.4, Page 4, Line 32.



Line  
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1 **TEP – Regulatory Asset Programs**

2 **Q19. What level of Regulatory Asset treatment is the Company proposing for its**  
3 **rebate programs?**

4 A19. The Company is proposing it be authorized to record up to \$128.3 million as a  
5 Regulatory Asset between 2025 and 2028 in support of its TEP rebate programs.  
6 The buildup of these targeted rebate amounts aligns with the Company’s TEP and  
7 Commission’s January 2025 Order and is shown in Table 1 below. Each rebate  
8 program is discussed in greater detail later in my testimony.

10 **Table 1 TEP Rebate Programs Cost Buildup (\$M)<sup>5</sup>**

| Segment      | Sub-segment                  | 2025         | 2026         | 2027         | 2028         | Total         |
|--------------|------------------------------|--------------|--------------|--------------|--------------|---------------|
| Residential  | LI SFH                       | 3.13         | 5.18         | 7.19         | 8.46         | 23.96         |
| Business     | LI MUD                       | 0.85         | 1.47         | 2.12         | 2.58         | 7.01          |
|              | Non-LI MUD                   | 2.83         | 4.57         | 6.19         | 7.08         | 20.66         |
|              | On-Route: DAC/Rural          | 3.64         | 5.11         | 6.23         | 6.58         | 21.56         |
|              | On-Route: Other <sup>6</sup> | 5.13         | 2.61         | 3.32         | 3.48         | 14.54         |
|              | Public L2                    | 1.00         | 1.04         | 1.13         | 1.22         | 4.39          |
| Fleet        | Transit Bus DCFC             | 0.56         | 0.56         | 0.56         | 0.63         | 2.31          |
|              | School Bus DCFC              | 1.61         | 1.68         | 1.82         | 1.96         | 7.07          |
|              | Other DCFC                   | 2.94         | 4.48         | 5.81         | 6.72         | 19.95         |
|              | Other L2                     | 0.98         | 1.54         | 2.04         | 2.28         | 6.84          |
| <b>Total</b> |                              | <b>22.66</b> | <b>28.24</b> | <b>36.40</b> | <b>40.99</b> | <b>128.29</b> |

<sup>5</sup> Differences in totals due to rounding

<sup>6</sup> When compared to original TEP plan: (1) 2025 amount increased by \$3.5 million of unused pre-2025 Business Charger Rebate funding consistent with Commissions January 2025 Order, and (2) annual totals reflect a reallocation to the Business Public L2 rebate program of \$1.0 million in 2025, 1.04 million in 2026, 1.13 million in 2027, and 1.22 million in 2028

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1 The Company further proposes to confirm that:

- 2 • Authorization to record rebates as a Regulatory Asset extends beyond the  
3 forward test year in the instant case (i.e., 2026) but not beyond the  
4 Company's TEP timeframe (i.e., 2028).  
5 • The Company can reallocate funding between rebate programs as needed.  
6 Said differently, the Commission is authorizing a total level of Regulatory  
7 Asset treatment, and not specific rebate program levels.

8

9 **Q20. Why is the Company proposing to confirm that authorization to record**  
10 **rebates as a Regulatory Asset extend beyond the forward test year in this case?**

11 A20. Regulatory Asset treatment is generally authorized for a given timeframe and for a  
12 maximum level of spending. Once the Company is beyond the authorized  
13 timeframe or above the authorized level of spending, it can no longer record  
14 expenditures as a Regulatory Asset and would either (1) need to cease spending, or  
15 (2) spend without cost recovery.

16

17 As it relates to the TEP, the Company is proposing to confirm that authorization to  
18 record rebates as a Regulatory Asset extend beyond the forward test year so that it  
19 does not need to stop issuing rebates at the end of 2026. Said differently, if the  
20 authorization to record rebates as a Regulatory Asset were to only extend through  
21 the forward test year in the instant case (i.e., 2026), the Company would need to  
22 suspend the issuance of those rebates at the end of 2026 until subsequent  
23 authorization could be granted in a future rate case.

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1 At a minimum, such an outcome would create a multiple-months gap in the  
2 availability and issuance of rebates. This would both hamper EV adoption in the  
3 Company's service territory and potentially create a negative and confusing  
4 experience for the Company's customers. Interruptions in issuing rebates is also  
5 highly inefficient and could lead to unnecessary costs, such as the need to update  
6 Company websites when rebates become unavailable and then again when they  
7 become available again.

8

9 **Q21. Why is the Company proposing to confirm it can reallocate funding between**  
10 **programs?**

11 A21. As described above, Regulatory Asset treatment is generally authorized for a given  
12 timeframe and for a maximum level of spending. As it relates to the Company's  
13 TEP rebate programs, if that maximum level of spending is applied to individual  
14 rebate programs, the Company would need to stop issuing rebates for each segment  
15 once that maximum level was met. For example, if funding for Residential LI SFH  
16 rebates was depleted, the Company would have to stop issuing these rebates, even  
17 if funds remained available in other segments.

18

19 As such, the Company proposes to confirm that it can reallocate funding between  
20 programs as needed. This will ensure that if a particular subsegment exceeds the  
21 Company's targeted adoption levels, rebates can continue to be issued if funding  
22 remains available in other areas. This allows the Company to remain flexible with  
23 its TEP rebate programs and respond to the prevailing adoption trends in its service  
24 territory.

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1 This flexibility is particularly important considering the Commission's direction in  
2 its January 2025 Order that the Company offer Public L2 Charger rebates. While  
3 the Commission issued that directive, it did not authorize incremental funding to  
4 support those rebates. Consequently, the Company must fund those rebates in 2025  
5 (the forward test year in that case) from other approved rebate programs. As such,  
6 the Company's position that it be allowed to reallocate funding between programs  
7 is aligned with the Commission's direction in Case No. U-21534.

8

9 **Q22. Does the Company get to keep any unused rebate funding?**

10 A22. No. When the Company issues a rebate, it records that amount as a Regulatory  
11 Asset. In a subsequent rate case, accumulated Regulatory Assets are addressed and  
12 proposed for recovery through base rates, generally over five years. This approach  
13 is currently applied to legacy Charging Forward Regulatory Asset costs, as  
14 sponsored by Company Witness Uzenski in Exhibit A-13, Schedule C5.9.1.

15

16 If the Company fails to issue the targeted level of rebates, it does not record the  
17 unused amounts as a Regulatory Asset, and does not ask for recovery of those  
18 amounts through base rates. Said differently, the Company's customers do not pay  
19 for unused rebate amounts.

20

21 For example, if the Commission authorizes Regulatory Asset treatment for up to  
22 \$10 million, but the Company only issues \$6 million of rebates, then only \$6  
23 million would be proposed for recovery through base rates in a future rate case. The  
24 \$4 million difference represents unused authorized funding and has no impact on  
25 customer rates.

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1 **Q23. What are the Company's TEP residential charger rebate targets?**

2 A23. The Company's TEP residential charger rebates were approved through the  
3 Commission's January 2025 Order. The rebates are designed to reimburse income-  
4 eligible customers for the full cost of a L2 Charger and associated installation. The  
5 Company estimates that on average the rebate amount will be \$2,200.

6

7 To be eligible for a residential rebate, a customer must be below 200% of the  
8 Federal Poverty Line (FPL) as well as agree to other terms and conditions. As  
9 described in the Company's TEP, the Company seeks to support 100% of this  
10 segment by issuing roughly 10,890 rebates over the 2025-2028 TEP timeframe. A  
11 breakdown of annual targeted rebate issuances and associated costs is provided in  
12 Table 2.

13

14 **Table 2 TEP Residential Charger Rebate Targets**

| Sub-segment | Target           | 2025  | 2026  | 2027  | 2028  | Total         |
|-------------|------------------|-------|-------|-------|-------|---------------|
| LI SFH      | Rebates Issued   | 1,421 | 2,355 | 3,269 | 3,844 | <b>10,889</b> |
|             | Total Cost (\$M) | 3.13  | 5.18  | 7.19  | 8.46  | <b>23.96</b>  |

15

16 **Q24. What are the Company's TEP business charger rebate targets?**

17 A24. The Company's TEP business charger rebates were approved through the  
18 Commission's January 2025 Order and target MUD, on-route, and other public  
19 chargers.

20

21 For MUDs, the Company offers L2 Charger rebates that differ depending on if the  
22 MUD serves predominantly LI customers or non-LI customers. LI MUD rebates

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1 are designed to reimburse the full cost of a L2 Charger and associated installation  
2 up to \$14,400<sup>7</sup>. Non-LI MUD rebates are offered at \$5,000<sup>8</sup>.

3

4 In either case, to be eligible for a rebate customers must install a charger within the  
5 Company's service territory, maintain the charger for at least five years, install a  
6 separate meter dedicated the charger, commit to 97% charger uptime, and agree to  
7 other terms and conditions. In addition, MUDs must demonstrate tenant interest in  
8 EV chargers. In alignment with the Commission's January 2025 Order, MUDs may  
9 self-attest to this tenant interest. Finally, LI MUDs must meet at least one of the  
10 following criteria: be owned and managed by a public entity, receive government  
11 subsidization requiring at least 40% of units for residents with household incomes  
12 not exceeding 60% of the area median income, or have at least 40% of residents  
13 participating in the Housing Voucher Program.

14

15 As described in the Company's TEP, the Company seeks to support 90% of LI  
16 MUDs charger deployments by issuing roughly 490 rebates over the 2025-2028  
17 TEP timeframe. The Company seeks to support 45% of Non-LI MUDs charger  
18 deployments by issuing roughly 4,130 rebates over the 2025-2028 TEP timeframe.  
19 A breakdown of annual targeted rebate issuances and associated costs is provided  
20 in Table 3.

---

<sup>7</sup> LI MUD rebates for Electric Choice customers are capped at \$5,000

<sup>8</sup> Non-LI MUD rebates for Electric Choice customers are offered at \$1,750

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1

**Table 3 TEP Business MUD L2 Charger Rebate Targets**

| Sub-segment | Target           | 2025 | 2026 | 2027  | 2028  | Total        |
|-------------|------------------|------|------|-------|-------|--------------|
| LI MUD      | Rebates Issued   | 59   | 102  | 147   | 179   | <b>487</b>   |
|             | Total Cost (\$M) | 0.85 | 1.47 | 2,12  | 2.58  | <b>7.01</b>  |
| Non-LI MUD  | Rebates Issued   | 565  | 914  | 1,237 | 1,416 | <b>4,132</b> |
|             | Total Cost (\$M) | 2.83 | 4.57 | 6.19  | 7.08  | <b>20.66</b> |

2

3 For on-route deployments, the Company offers DC Fast Charger (DCFC) rebates  
4 that differ depending on where the charger is being located. DCFC chargers being  
5 deployed in a DAC or rural community can receive a rebate of \$70,000<sup>9</sup>. DCFC  
6 chargers being deployed in a non-DAC/non-rural community can receive a rebate  
7 of \$50,000<sup>10</sup>.

8

9 In either case, to be eligible for a rebate customers must install a charger with  
10 capacity of at least 150 kW within the Company's service territory, maintain the  
11 charger for at least five years, install a separate meter dedicated to the charger,  
12 commit to 97% charger uptime, and agree to other terms and conditions. Further,  
13 chargers must be in a well-lit area, publicly accessible 24/7 within one mile of a  
14 major throughway exit, and accessible to and usable by people with disabilities if  
15 the entity is subject to the ADA or the Architectural Barriers Act.

16

17 As described in the Company's TEP, for DAC/Rural On-Route DCFCs the  
18 Company seeks to support 35% of deployments by issuing roughly 310 rebates over  
19 the 2025-2028 TEP timeframe.

<sup>9</sup> DAC/Rural On-Route DCFC rebates for Electric Choice customers are offered at \$24,500

<sup>10</sup> Non-DAC/Non-Rural On Route DCFC rebates for Electric Choice customers are offered at \$17,500

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1 For Non-DAC/Non-Rural On-Route DCFCs, the Company originally sought to  
2 support roughly 35% of deployments over the 2025-2028 TEP timeframe.  
3 However, as discussed earlier in my testimony, in its January 2025 Order the  
4 Commission directed the Company to reallocate any unused legacy Business  
5 Charger Rebate funding to Non-DAC/Non-Rural On-Route DCFC rebates, which  
6 added \$3.53 million of funding to this segment. However, the Commission also  
7 directed the Company to offer Public L2 Charger rebates, but did not authorize  
8 incremental funding to do so. As such, the Company reallocated \$4.39 million from  
9 non-DAC/non-rural on-route DCFC rebates to fund Public L2 Charger rebates.  
10 Effectively, the net funding changes allows the Company to maintain its support of  
11 roughly 35% of non-DAC/non-rural on-route DCFC charger deployments by  
12 issuing roughly 290 rebates over the 2025-2028 TEP timeframe.

13

14 The Company notes that, as described earlier in my testimony, it is proposing to  
15 confirm that it can continue to reallocate funding between programs as needed to  
16 accommodate prevailing adoption trends.

17

18 A breakdown of annual targeted rebate issuances and associated costs is provided  
19 in Table 4.

20

21 **Table 4 TEP Business On-Route DCFC Rebate Targets**

| Sub-segment           | Target           | 2025 | 2026 | 2027 | 2028 | Total        |
|-----------------------|------------------|------|------|------|------|--------------|
| DAC/Rural             | Rebates Issued   | 52   | 73   | 89   | 94   | <b>308</b>   |
|                       | Total Cost (\$M) | 3.64 | 5.11 | 6.23 | 6.58 | <b>21.56</b> |
| Non-DAC/<br>Non-Rural | Rebates Issued   | 103  | 52   | 66   | 70   | <b>291</b>   |
|                       | Total Cost (\$M) | 5.13 | 2.61 | 3.32 | 3.48 | <b>14.54</b> |



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1 As it relates to other public charger deployments, in the Commission's January  
2 2025 Order, the Company was ordered to offer rebates for all other public L2  
3 chargers. Customers installing a Public L2 Chargers can receive a rebate of \$2,500  
4 per port<sup>11</sup>. To be eligible for this rebate, customers must install a charger within the  
5 Company's service territory, maintain the charger for at least five years, install a  
6 separate meter dedicated to the charger, commit to 97% charger uptime, and agree  
7 to other terms and conditions. Further, chargers must be in a well-lit area, publicly  
8 accessible, and usable by people with disabilities if the entity is subject to the ADA  
9 or the Architectural Barriers Act.

10

11 As discussed previously, while the Commission ordered the Company to offer  
12 Public L2 Charger rebates, it did not authorize any incremental funding for such  
13 rebates. As such, the Company has initially reallocated funding from Non-  
14 DAC/Non-Rural On-Route DCFC rebates to the Public L2 Charger rebates. The  
15 Company again notes that in the instant case it is seeking to confirm that it can  
16 reallocate funding as needed on an ongoing basis to accommodate prevailing  
17 adoption trends and adjustments to future rebate offerings.

18

19 A breakdown of annual targeted rebate issuances for Public L2 Chargers and  
20 associated costs is provided in Table 5. The Company estimates that the targeted  
21 level of rebate issuance would support roughly 5% of Public L2 deployments.

---

<sup>11</sup> Public L2 Charger rebates for Electric Choice customers are offered at \$875 per port

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**Table 5 TEP Business Public L2 Rebate Targets**

| Sub-segment | Target           | 2025 | 2026 | 2027 | 2028 | Total        |
|-------------|------------------|------|------|------|------|--------------|
| Public L2   | Rebates Issued   | 400  | 417  | 452  | 487  | <b>1,757</b> |
|             | Total Cost (\$M) | 1.00 | 1.04 | 1.13 | 1.22 | <b>4.39</b>  |

2

3 **Q25. What is the Company targeting related to its TEP fleet rebate program?**

4 A25. The Company's TEP fleet charger rebates were approved through the  
5 Commission's January 2025 Order and target transit bus DCFCs, school bus  
6 DCFCs, other fleet DCFCs, and L2 deployments.

7

8 For transit bus fleets, school bus fleets, and other fleets the Company offers rebates  
9 of \$70,000<sup>12</sup>. To be eligible for a rebate customers must install a charger with  
10 capacity of at least 150 kW within the Company's service territory, maintain the  
11 charger for at least five years, utilize a qualified legacy Network Provider or install  
12 a separate meter dedicated to the charger, commit to 97% charger uptime, and agree  
13 to other terms and conditions. Lastly, customers must have or plan to purchase EVs  
14 (plug-in hybrid or battery electric vehicle, including Class 1-8 on road vehicles)  
15 within 24 months of the rebate application date.

16

17 Additionally, schools must install bi-directional (i.e., vehicle-to-grid) chargers to  
18 be eligible for the full rebate. In its January 2025 Order the Commission directed  
19 the Company to explore tiered rebates for school bus DCFC deployments without  
20 bi-directional charging. This is discussed later in my testimony.

21

---

<sup>12</sup> Fleet rebates for Electric Choice customers are offered at \$24,500

Line  
No.

1 The Company also offers L2 Charger rebates for fleets of \$2,500 per port<sup>13</sup>. To be  
2 eligible for a rebate, customers must install a charger within the Company's service  
3 territory, maintain the charger for at least five years, utilize a qualified legacy  
4 Network Provider or install a separate meter dedicated to the charger, commit to  
5 97% charger uptime, and agree to other terms and conditions. Lastly, customers  
6 must have or plan to purchase EVs (plug-in hybrid or battery electric vehicle,  
7 including Class 1-8 on road vehicles) within 24 months of the rebate application  
8 date.

9

10 Through these rebates the Company seeks to support 100% of transit bus DCFC  
11 deployments, 30% of school bus DCFC and other fleet DCFC deployments, and  
12 90% of fleet L2 Charger deployments. A breakdown of annual targeted rebate  
13 issuances and associated costs is provided in Table 6

14

15 **Table 6 TEP Business Fleet Charger Rebate Targets**

| Sub-segment      | Target           | 2025 | 2026 | 2027 | 2028 | Total        |
|------------------|------------------|------|------|------|------|--------------|
| Transit Bus DCFC | Rebates Issued   | 8    | 8    | 8    | 9    | <b>33</b>    |
|                  | Total Cost (\$M) | 0.56 | 0.56 | 0.56 | 0.63 | <b>2.31</b>  |
| School Bus DCFC  | Rebates Issued   | 23   | 24   | 26   | 28   | <b>101</b>   |
|                  | Total Cost (\$M) | 1.61 | 1.68 | 1.82 | 1.96 | <b>7.07</b>  |
| Other Fleet DCFC | Rebates Issued   | 42   | 64   | 83   | 96   | <b>285</b>   |
|                  | Total Cost (\$M) | 2.94 | 4.48 | 5.81 | 6.72 | <b>19.95</b> |
| Fleet L2         | Rebates Issued   | 391  | 617  | 814  | 913  | <b>2,735</b> |
|                  | Total Cost (\$M) | 0.98 | 1.54 | 2.04 | 2.28 | <b>6.84</b>  |

<sup>13</sup> Fleet L2 Charger rebates for Electric Choice customers are offered at \$875 per port

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No.

**Q26. Is the Company proposing to offer tiered rebates based on charger capacity output for school bus fleet DCFC deployments that do not utilize bi-directional chargers?**

A26. Yes. The Company is proposing tiered rebates based on charger capacity output for school bus fleet DCFC deployments that do not utilize bi-directional chargers. Following the structure of the legacy Charging Forward's Business and eFleet Charger Rebates for DCFCs, the Company is proposing rebates starting at \$12,000 for 24 kW and up to \$70,000 for 150 kW or higher. The full list of rebate tiers is captured in Table 7 below.

**Table 7 Proposed School Bus Fleet DCFC Tiered Rebates**

| <b>DCFC Charger Capacity Output (kW)</b> | <b>Rebate Amount (\$)</b> |
|------------------------------------------|---------------------------|
| 24                                       | 12,000                    |
| 50                                       | 18,000                    |
| 62.5                                     | 25,000                    |
| 100                                      | 30,000                    |
| 150+                                     | 70,000                    |

The Company's proposal is informed by data from the legacy eFleets program over the past four years, where two schools installed 20 DC fast chargers with capacity outputs of 24 kW and 60 kW, receiving rebate amounts of \$12,000 and \$18,000, respectively. The average capacity output and rebate amounts from these installations highlight the importance of designing rebates to incentivize the deployment of efficient chargers. This tiered rebate structure not only encourages the adoption of higher-capacity chargers but also ensures that schools receive financial support proportional to their investment.

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No.

**Q27. What level of Regulatory Asset treatment is the Company proposing related to the Emerging Technology Fund and what will it support?**

A27. The Company is proposing it be authorized to record up to \$4.0 million as a Regulatory Asset between 2025 and 2028 in support of its Emerging Technology Fund (ETF). Unlike its rebate programs, the Company is proposing the level of Regulatory Asset treatment be capped at \$1.0 million per year. This maintains the level of authorization granted by the Commission for 2025. Further, the Company's proposal is consistent with the Commission's guidance in its December 2023 Order in which it stated, "the Commission adopts the PFD and declines to make the pilot permanent but extends it for five years" (page 262).

As discussed in the Company's TEP, the Emerging Technology Fund is a grant program that aims to enable timely funding of prudent innovative pilots in a rapidly evolving market. Projects considered include EV-grid integration solutions, novel engagement of underserved communities, and second-life applications for used EV batteries. Organizations seeking funding are vetted via three stages of review: initial screening by the EV team, cross-functional review by other business units within DTE Electric, and the final review by the Emerging Technology Fund Advisory Committee that was established in March 2023. Each year, the Advisory Committee convenes multiple times a year for rounds of reviews until the \$1.00 million funding is exhausted for deserving proposals.

For example, the Emerging Technology Fund contributed to the Forth Mobility Affordable Mobility Pilot ("AMP") pilot in 2023 and approved an extension to additional locations in 2024. The Forth AMP Pilot is a low-cost EV car-sharing

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1 pilot that provides EV options to low-income residents in Detroit and Ann Arbor.  
2 As of December 2024, the pilot had provided 583 trips totaling over 5,700 hours  
3 and over 31,000 EV Miles.

4  
5 In its January 2025 Order, the Commission directed “the company to continue to  
6 provide an annual update on Emerging Technology pilots and learnings in its next  
7 EV Annual Status Report” (January 2025 Order; page 339). The Company plans to  
8 comply with this directive in its next TEP Annual Status report which will be filed  
9 by June 1, 2026, and cover Calendar Year 2025.

10

11 **TEP – Capital Programs**

12 **Q28. What is the status of the Company’s Charging Hubs Pilots?**

13 A28. The Company originally received approval for the Charging Hubs Pilot through the  
14 Commission’s November 2022 Order. In that Order the Commission approved the  
15 construction of up to two Charging Hubs designed for medium- and heavy-duty  
16 fleet vehicles, each providing multiple fast chargers in a single location.

17

18 The first Charging Hub is being located in Redford, MI, and is part of a  
19 collaborative effort with the State of Michigan and Detroit Diesel (Daimler Truck  
20 North America). As discussed previously, the Company and its partners applied for  
21 a grant through the DOT’s RAISE program and were awarded \$8.5 million in  
22 funding for the Charging Hub.

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1 Since receiving initial approval of the investment, the project has faced delays. For  
2 example, State of Michigan Spending Authority to initiate the use of RAISE grant  
3 funds was not received until August 2024.

4

5 Despite the delays, progress has been made. For example:

6 • Partnership Agreements between the Company and its project partners,  
7 which define roles and responsibilities, the scope of work, and other  
8 financial and operational details are being pursued;

9 • The State of Michigan approved and signed the Federal Grant Agreement  
10 in January, enabling access to the RAISE grant funds; and

11 • The State of Michigan identified a dedicated, third-party project  
12 management consultant to manage the project and ensure coordination  
13 between its partners.

14

15 At the time of filing, the Company along with its project partners are awaiting  
16 DOT's execution of the Federal Grant Agreement and subsequent disbursement of  
17 RAISE grant funds to the State of Michigan. These activities have been delayed,  
18 partly due to ambiguity surrounding Executive Orders signed by President Donald  
19 Trump shortly after his inauguration. Site work is expected to begin by mid-year  
20 2025.

21

22 While the Company has pursued opportunities for a second hub as explained  
23 previously in my testimony, it has not yet been successful in securing grant funding  
24 that would be needed to support a second site.

Line  
No.

1   **Q29. What level of capital investment is the Company proposing for the Charging**  
2       **Hub Pilots?**

3   A29. The Company is proposing recovery of \$1.5 million in capital investment through  
4       2025 in support of its first Charging Hub, representing incremental investment  
5       above the RAISE grant.

6  
7       The Company is not proposing any investment associated with a second Charging  
8       Hub in the instant case. Said differently, at the time of filing the Company does not  
9       have a specific second hub opportunity mature enough to warrant a request of  
10      investment recovery.

11

12   **Q30. What level of capital investment is the Company proposing for TEP IT**  
13       **Capabilities and what will it support?**

14   A30. The Company is proposing recovery of \$0.3 million of capital investment in 2026  
15       to support TEP IT Capabilities. This is in addition to \$1.6 million of bridge period  
16       investment the Company intends to spend in 2025. The 2025 investment will be  
17       used to build data capabilities and dashboards for TEP metric tracking and  
18       reporting. For example, these new capabilities will support the reporting of data  
19       required for the Company's TEP Annual Report. The Company has launched a  
20       Request for Proposal to select third-party vendors for the dashboard buildout. The  
21       2026 investment will be used to further refine and/or enhance the dashboard  
22       capabilities.



Line  
No.

1 **TEP – O&M Programs**

2 **Q31. What level of O&M spending is the Company proposing for Education and**  
3 **Outreach (E&O) and what activities will it support?**

4 A31. The Company is proposing \$1.5 million of O&M spending in 2026 for E&O, which  
5 maintains the level of spending authorized by the Commission in both its December  
6 2023 Order and January 2025 Order in the Company's most recent electric rate  
7 cases. Further, the Company's proposal is consistent with the Commission's  
8 guidance in the December 2023 Order in which it stated "the Commission agrees  
9 with the [Administrative Law Judge] that the E&O pilot should be made permanent  
10 and the requested funding approved because the record establishes that there is a  
11 long-term need for such a program" (page 258).

12

13 As discussed in the Company's TEP (Exhibit A-29, Schedule S1), E&O supports  
14 all of the Company's customer outreach activities such as in-person EV experience  
15 Ride and Drives, emails, bill messages, print collateral, social posts, digital  
16 marketing, the Virtual Showroom and website updates.

17

18 In addition, the Company has rolled its eFleet Advisory Services under the ongoing  
19 E&O umbrella. The Company is also exploring a similar service for MUDs to ease  
20 the charger installation process for MUD owners.

21

22 **Q32. What level of O&M spending is the Company proposing for Program**  
23 **Administration and what activities will it support?**

24 A32. The Company is proposing \$1.8 million of O&M spending in 2026 for Program  
25 Administration. The Company's proposal is consistent with the Commission's

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1 December 2023 Order and January 2025 Order in which it approved the  
2 establishment of a 14-member permanent EV team to develop and administer the  
3 Company's EV programming. More specifically, the permanent EV team is  
4 responsible for strategy, program execution, and facilitating EV-related federal  
5 funding opportunities for Southeast Michigan.

6

7 In addition to supporting the permanent EV team, Program Administration costs  
8 support EV industry knowledge sharing such as attending transportation  
9 electrification industry working groups and conferences and paying for  
10 membership and software maintenance fees for program management tools such as  
11 the eFleet Total Cost of Ownership (TCO) and the web-based PowerClerk® rebate  
12 application subscription.

13

14 **Q33. Are there any costs presented in Exhibit A-12, Schedule B5.9 that have not yet**  
15 **been discussed?**

16 A33. Yes. Exhibit A-12, Schedule B5.9 includes the costs associated with legacy  
17 programs that the Company does not propose to continue as part of its EV  
18 programming in 2026. These programs include:

19 • Capital Expenditures:

20 ○ Program Administration (line 2). In Case No. U-21534 the Company  
21 proposed that all Program Administration costs be treated as O&M  
22 beginning in 2025. In its January 2025 Order the Commission  
23 approved this approach. Exhibit A-12, Schedule B5.9, Line 2  
24 captures legacy capital investment associated with Program

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1 Administration incurred before the approved change to cost  
2 treatment.

3 ○ Home Charger Installation (line 4). In its December 2023 Order the  
4 Commission directed the Company to transition the Home Charger  
5 Installation program to a Value Added Programs and Services  
6 (VAPS) offering, which the Company did in 2024. The costs  
7 presented in Exhibit A-12, Schedule B5.9, Line 4 are legacy costs  
8 incurred prior to the transition to the VAPS offering.

9 • Regulatory Asset Expenditures:

10 ○ Program Administration (line 13). In Case No. U-21534 the  
11 Company proposed that all Program Administration costs be treated  
12 as O&M beginning in 2025. In its January 2025 Order the  
13 Commission approved this approach. Exhibit A-12, Schedule B5.9,  
14 Line 13 captures legacy Regulatory Asset costs associated with  
15 Program Administration incurred before the approved change to cost  
16 treatment.

17 ○ Education and Outreach (line 14). In Case No. U-21534 the  
18 Company proposed that all Education and Outreach costs be treated  
19 as O&M beginning in 2025. In its January 2025 Order the  
20 Commission approved this approach. Exhibit A-12, Schedule B5.9,  
21 Line 14 captures legacy Regulatory Asset costs associated with  
22 Education and outreach incurred before the approved change to cost  
23 treatment.

24 ○ Business Charger Installations (line 17). In its December 2023 Order  
25 the Commission directed the Company to transition the Business

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1 Charger Installation program to a VAPS offering if the Company  
2 wished to continue the program. The Company elected to discontinue  
3 the program in 2024. The costs presented in Exhibit A-12, Schedule  
4 B5.9, Line 17 are legacy costs incurred prior to the discontinuation  
5 of the program.

6 ○ School Bus Chargers (line 19). In its December 2023 Order the  
7 Commission approved the establishment of a School Bus Charger  
8 pilot. The costs presented in Exhibit A-12, Schedule B5.9, Line 19  
9 are legacy costs incurred to execute that pilot in 2024. The Company  
10 is not proposing to extend that pilot in the instant case, although the  
11 Company will continue to support the electrification of school busses  
12 through its proposed eFleet rebates.

13

14 **Merchant Fees**

15 **Q34. What are merchant fees?**

16 A34. Merchant fees are the transactional costs associated with the processing of debit  
17 and credit card payments. These costs are borne by the Company and levied by the  
18 customer's debit and credit card issuer and payment processor.

19

20 **Q35. How have merchant fees traditionally been recovered from customers?**

21 A35. Historically, merchant fees were treated as an O&M expense and recovered through  
22 base rates. Said differently, merchant fees have traditionally been socialized across  
23 the Company's customers.

24

Line  
No.

1   **Q36. Has the Commission provided any recent guidance on the recoverability of**  
2       **merchant fees?**

3   A36. Yes. The Commission first provided guidance on the recoverability of merchant  
4       fees in the Company's most recent gas rate case. In its November 7, 2024 Order in  
5       Case No. U-21291 (November 2024 Order) the Commission stated:

6

7           "...although small businesses and small-to-medium size C&I customers may  
8       appreciate the flexibility and ease of paying their utility bills with a credit card,  
9       the merchant fee of \$4.72 per transaction should not be socialized across DTE  
10       Gas's customer base." (page 158)

11

12       And

13

14           "...that because the merchant fees associated with residential customers was  
15       not contested in this case, it is not addressed in this order. However, the  
16       Commission finds that the same reasoning would apply: it is not reasonable or  
17       prudent to socialize over the utility's customer base the merchant fees for  
18       customers who choose to pay by credit card." (page 158)

19

20       Further, in its January 2025 Order the Commission provided the following  
21       guidance:

22

23           "As it recently did in the November 7 order, the Commission agrees with the  
24       Attorney General that the company has failed to adequately explain why  
25       customers should assume the merchant fee costs for non-residential customers

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1           when other, cheaper methods of payment are available...the Commission  
2           adopts the Attorney General's \$3.5 million disallowance for non-residential  
3           merchant fees for the projected test year to be applied to the agreed upon test  
4           year projection..." (page 232)

5

6           The Commission additionally reiterated its guidance from the November 7 Order  
7           related to residential merchant fee recoverability.

8

9   **Q37. Is the Company proposing to recover non-residential merchant fees through**  
10   **base rates?**

11   A37. No. In alignment with the Commission's November 2024 Order and January 2025  
12   Order, the Company is not proposing to recover non-residential merchant fees  
13   through base rates. Exhibit A-13, Schedule C5.7.1, page 1, Line 4 reflects this  
14   proposed approach with projected test period costs of \$0.

15

16   **Q38. Will DTE still offer non-residential customers the ability to utilize a credit or**  
17   **debit card to pay their utility bill?**

18   A38. Yes. However, instead of socializing those fees across its customer base through  
19   base rates, the Company plans to apply a service fee to customers that elect to use  
20   a credit or debit card to pay their utility bill.

21

22           While the specific fees the Company will apply have not been determined at the  
23           time of filing of the instant case, it is the Company's intent to design the service  
24           fees to only cover the merchant fees it expects to incur (i.e., the Company does not  
25           intend to generate a margin from the service fees).

Line  
No.

1   **Q39. Are there any additional costs associated with the change in non-residential**  
2       **merchant fee recoverability?**

3   A39. Yes. Capital investment will be needed to enable the application of a service fee to  
4       customer bills. Company Witness Ambrose discusses this investment in his  
5       testimony.

6  
7   **Q40. Is the Company proposing to recover residential merchant fees through base**  
8       **rates?**

9   A40. Yes. While the Company acknowledges the Commission's guidance in its  
10       November 2024 Order and January 2025 Order related to the residential merchant  
11       fees, the Company maintains its position that these fees are best recovered through  
12       base rates. It is therefore proposing recovery of these fees as captured in Exhibit  
13       A-13, Schedule C5.7.1, page 1, Line 3.

14  
15   **Q41. Why does the Company believe residential merchant fees are best recovered**  
16       **through base rates?**

17   A41. If merchant fees are not recovered through base rates, then to allow customers to  
18       use a credit or debit card, the Company must charge an additional fee to customers  
19       that elect to use these payment types. In effect, when compared to the current  
20       approach, such a change represents a cost shift from non-card users to card users  
21       since merchant fees are removed from base rates and instead assessed directly to  
22       the users of these payment types. This is similar to the approach the Company is  
23       taking for non-residential customers, as discussed previously in my testimony.

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1           However, the Company maintains its belief that residential merchant fees are best  
2           recovered through base rates given the makeup of the users of credit and debit cards.  
3           More specifically, the Company's low-income customers have relatively high  
4           credit card usage compared to the Company's other residential customers.  
5           Company Witness Sparks presents an analysis in his testimony that shows that low-  
6           income customers utilize a credit card for 69% of payments, compared to 44% for  
7           other customers. As such, assessing a service fee directly to customers (instead of  
8           socializing those fees through base rates) would disproportionately impact low-  
9           income customers. The Company does not believe it appropriate to impose  
10          additional costs on its most vulnerable customers, as such a change would do.

11

12          In addition, the Company is concerned about the impact to the Company's  
13          uncollectible expense that such a change would have. When a customer elects to  
14          use a credit card to pay their bill, the risk of customer non-payment is borne by the  
15          card issuer. If that same customer elects to no longer use their credit card because  
16          they would be subject to an additional fee, the risk of customer non-payment is  
17          shifted to the Company and its other customers.

18

19   **Q42. Are there any additional considerations related to residential merchant fee**  
20   **recovery?**

21   A42. Yes. If the Commission rejects the Company's proposed recovery of residential  
22   merchant fees, then the Company urges the Commission to allow time for an  
23   appropriate transition that sufficiently educates customers on the change. This can  
24   be accomplished in two ways:



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- 1 • Approve recovery of residential merchant fees in the forward test year (i.e.,
- 2 2026) but direct the Company to not propose recovery of such fees in its next
- 3 rate case; or
- 4 • Authorize Regulatory Asset treatment of any residential merchant fees that
- 5 are incurred (1) after an Order is received in the instant case, and (2) before
- 6 the Company is able to implement a solution to assess a fee directly to
- 7 customers (including time for customer education), not to extend beyond the
- 8 forward test year in the instant case (i.e., 2026). Any accumulated
- 9 Regulatory Asset associated with this approach could then be addressed in a
- 10 future rate case.

11

12 **Full Time of Day (TOD) Rollout Expenses**

13 **Q43. What was the role of Customer Outreach in the Company's full TOD rollout?**

14 A43. Customer Outreach communicated the transition for the full TOD rollout to ensure

15 that all residential electric customers were informed that their base rate would be

16 changed to a new TOD rate in March 2023.

17 **Q44. What was the 2023 O&M expense for Customer Outreach?**

18 A44. The Company incurred \$0.5 million of O&M expenses related to Customer

19 Outreach for the full TOD rollout in 2023. This is captured in Exhibit A-13,

20 Schedule C5.9.2, Line 10. The Company did not incur any additional O&M

21 expenses related to Customer Outreach for the full TOD rollout beyond 2023.

22

23 As explained by Company Witness Uzenski, these expenses were approved by the

24 Commission for deferral and amortization over a period of five years, including

25 the forward test year in the instant case. The amortization schedule sponsored by

Line  
No.

1 Company Witness Uzenski is captured in Exhibit A-13, Schedule C5.9.3.

2

3 **Electric Regulated Marketing Operations & Maintenance Expense**

4 **Q45. What does Electric Regulated Marketing O&M expense include?**

5 A45. Electric Regulated Marketing O&M expense includes the following areas:

- 6       ▪ Major Account Services, which manages new and existing customer
- 7       relationships for C&I customer classes,
- 8       ▪ Electric Marketing, which manages marketing campaigns to educate
- 9       customers, develops new product and service offerings, and performs project
- 10      management,
- 11      ▪ Economic Development, which seeks to stimulate local economic growth
- 12      and activity, including job growth through business attraction and expansion,
- 13      ▪ Demand Response Portfolio costs, supported by Company Witness Leuker,
- 14      ▪ TEP O&M expense, explained above, and
- 15      ▪ Amortization of the Charging Forward regulatory assets, supported by
- 16      Company Witness Uzenski.

17

18 **Q46. Can you explain the normalizations reflected in Column (e) on Exhibit A-13,**  
19 **Schedule C5.9?**

20 A46. Column (e) on line 15 is an O&M increase of \$6.4 million for the normalization of  
21 temporary cost reductions in 2023.

22

23 **Q47. What makes up the \$6.4 million of temporary cost reductions in 2023?**

24 A47. The details are listed in footnote 3 of Exhibit A-13, Schedule C5.9 and include \$4.8  
25 million related to a temporary pause of customer outreach to promote clean energy

Line  
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1 adoption, \$1.0 million related to deferred hiring, and \$0.5 million related to a  
2 temporary suspension of training and other expenditures related to research and  
3 best practice implementation needed to improve customer experience. These  
4 temporary reductions were taken to mitigate the financial challenges experienced  
5 by the Company in 2023 as further discussed by Witness Bruzzano and are not  
6 expected to recur in the projected test period.

7

8 **Q48. What is the total Electric Regulated Marketing O&M expense for the**  
9 **projected test period that the Company is proposing for recovery?**

10 A48. As captured in Exhibit A-13, Schedule C5.9, Line 15, Column (l), the Company is  
11 proposing recovery of \$32.1 million of Electric Regulated Marketing O&M  
12 expense for projected test period.

13

14 This is a \$11.1 million increase over the adjusted historical test period O&M  
15 expense of \$21.0 million (Line 15, Column (f) of the same exhibit).

16

17 **Q49. What is driving the \$11.1 million increase between the adjusted historical test**  
18 **period and the projected test period?**

19 A49. The Company is proposing an increase of \$11.1 million based on the following  
20 changes to the adjusted historical 2023 Electric Marketing O&M expense:

- 21 1. \$1.9 million increase due to inflation factors as supported by Company Witness  
22 Uzenski and reflected in Exhibit A-13, Schedule C5.9, Columns (g)-(i);  
23 2. \$1.8 million decrease related to Voluntary Separation Incentive Program  
24 (VSIP) program savings. \$1.2 million of this is reflected in Exhibit A-13,  
25 Schedule C5.9, Line 4, Column (j) and \$0.5 million is incorporated into Line 9,

Line  
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1 Column (j) of the same exhibit. Company Witness Leslie explains this program  
2 and associated savings in further detail;

3 3. \$4.1 million increase related to Demand Response (DR) programs supported by  
4 Company Witness Leuker and incorporated into in Exhibit A-13, Schedule  
5 C5.9, Line 9, Column (j);

6 4. \$2.3 million increase related to TEP E&O and Program Administration O&M  
7 expense supported earlier in my testimony (Exhibit A-12, B5.9, Lines 8-11) and  
8 reflected in Exhibit A-13, Schedule C5.9, Line 10, Column (j). The majority of  
9 this increase is related to updated cost treatment approved by the Commission  
10 in its January 2025 Order. More specifically, prior to 2025 (including the  
11 historic test period in the instant case) a portion of TEP E&O and Program  
12 Administration was authorized for Regulatory Asset treatment. Starting in  
13 2025, all TEP E&O and Program Administration is treated as O&M. As such,  
14 the increase in O&M expense is not reflective only of increased projected  
15 spending, but also of a shift in cost treatment to more O&M (and less  
16 Regulatory Asset)<sup>14</sup>; and

17 5. \$4.6 million increase related to Charging Forward Regulatory Asset  
18 amortization supported by Company Witness Uzenski (Exhibit A-13, Schedule  
19 C5.9.1, Line 13) and reflected in Exhibit A-13, Schedule C5.9, Line 11  
20

21 **Q50. What are your conclusions regarding the level of Electric Regulated**  
22 **Marketing O&M expense for the projected test period?**

23 A50. The Electric Regulated Marketing O&M expense is reasonable, prudent, and  
24 necessary to support the programs proposed by the Company in the instant case, to

---

<sup>14</sup> In 2023, total TEP E&O and Program Administration spending was \$2.72 million (Exhibit A-12, Schedule B5.9, Lines 9-10 and 13-14, Column (b))

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1 maintain the existing level of customer support to C&I Major Account Services  
2 customers, to support the Company's economic development activities, and to  
3 educate all customers on Company offerings.

4

5 **Q51. Does this complete your direct testimony?**

6 A51. 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-21860

QUALIFICATIONS  
  
AND  
  
DIRECT TESTIMONY  
  
OF  
  
TIMOTHY J. LEPCZYK

**DTE ELECTRIC COMPANY**  
**QUALIFICATIONS AND DIRECT TESTIMONY OF TIMOTHY J. LEPCZYK**

Line  
No.

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

2   A1.   My name is Timothy J. Lepczyk (he/him/his). My business address is One Energy  
3           Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate  
4           Services, LLC, a subsidiary of DTE Energy Company (DTE Energy), as Assistant  
5           Treasurer and Director of Corporate Finance, Insurance and Development.

6

7   **Q2.   On whose behalf are you testifying?**

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

9

10   **Q3.   What is your educational background?**

11   A3.   I graduated from Georgetown University in 2004 with a Bachelor of Business  
12           Administration degree, with a concentration in International Business. In 2008, I  
13           graduated with my MBA from the University of Michigan, with a focus in Finance  
14           and Corporate Strategy.

15

16   **Q4.   What is your work experience?**

17   A4.   I began my employment with Ford Motor Company in the summer of 2004 as a  
18           financial analyst within that company's Dearborn Stamping facility. In 2006, I left  
19           to pursue my MBA. In 2008, after graduation, I went to work for Booz & Company,  
20           a management consultancy, where I focused on the automotive and industrial  
21           sectors. I worked at Booz & Company from 2008 until 2013 when I joined DTE  
22           Energy.

23

24           In 2013, I joined DTE Energy as a Manager on the Corporate Strategy team where  
25           I was the lead analyst for various projects and studies primarily relating to the Gas

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1 Storage and Pipeline business. In 2014, I formally accepted a position within the  
2 Gas Storage and Pipeline team as Manager in their strategy group where I was  
3 responsible for various economic analyses (e.g., natural gas supply and demand  
4 fundamentals) and for assessing potential new acquisition opportunities. In 2016, I  
5 accepted the position of Manager for the Corporate Development team where I was  
6 responsible for managing DTE Energy's capital investment process and various  
7 valuation processes (for example, DTE Energy's annual Goodwill impairment  
8 assessment). In addition, I led broader strategy initiatives including the analysis,  
9 which ultimately led to our decision to spin off the Midstream business segment.

10

11 In 2021, I accepted my current position, Assistant Treasurer and Director of  
12 Corporate Finance, Insurance and Development.

13

14 **Q5. What are your current duties and responsibilities?**

15 A5. I am responsible for assisting the Treasurer in managing the capital needs of the  
16 Company. These responsibilities include managing corporate liquidity and  
17 financing activities such as the raising of both equity capital and capital markets  
18 debt for DTE Energy, DTE Electric, and DTE Gas Company (DTE Gas). I assist  
19 in maintaining relationships with the commercial and investment banking  
20 community, interact with the rating agencies, and execute corporate financial  
21 policies, particularly in the areas of balance sheet management, debt issuances, and  
22 agency ratings. In addition, I manage the Company's capital investment approval  
23 and review process along with managing the Company's property and liability  
24 insurance function.



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

3   A6.   Yes, I have. I have sponsored testimony in the following cases:

4           U-20836       DTE Electric 2022 General Rate Case

5           U-21193       DTE Electric 2022 Integrated Resource Plan

6           U-21338       DTE Electric 2023 Securitization

7           U-21291       DTE Gas 2024 General Rate Case

8           U-21297       DTE Electric 2023 General Rate Case

9           U-21534       DTE Electric 2024 General Rate Case

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1 **Purpose of Testimony**

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

3 A7. The purpose of my testimony is to support DTE Electric's projected capital  
4 structure and the cost of its long- and short-term debt to be used in determining  
5 DTE Electric's overall rate of return in this proceeding. In addition, I discuss in  
6 greater depth the Department of Energy's Section 1706 loan program, to which  
7 DTE Electric has applied. Last, I discuss the anticipated transfer of tax credits  
8 associated with the Trenton Energy Storage System.

9

10 **Q8. How is your testimony organized?**

11 A8. My testimony is organized as follows:

12 I. Summary of Recommendations

13 II. Development of Capital Structure

14 III. Development of Cost Rates

15 IV. Securitization

16 V. Section 1706 Loan Program

17 VI. Investment Tax Credits

18 VII. Summary and Conclusions

19

20 **Q9. Are you sponsoring any exhibits in this proceeding?**

21 A9. Yes. I am supporting the following exhibits:

| 22 | <u>Exhibit</u> | <u>Schedule</u> | <u>Description</u>                 |
|----|----------------|-----------------|------------------------------------|
| 23 | A-1            | A2              | Historical Financial Metrics       |
| 24 | A-4            | D2              | Historical Cost of Long-Term Debt  |
| 25 | A-4            | D3              | Historical Cost of Short-Term Debt |

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|   |      |      |                                                   |
|---|------|------|---------------------------------------------------|
| 1 | A-4  | D4   | Historical Cost of Preferred and Preference Stock |
| 2 | A-4  | D5   | Historical Cost of Common Shareholders' Equity    |
| 3 | A-11 | A2   | Projected Financial Metrics                       |
| 4 | A-14 | D1.1 | Peer Group Common Equity                          |
| 5 | A-14 | D2   | Projected Cost of Long-Term Debt                  |
| 6 | A-14 | D3   | Projected Cost of Short-Term Debt                 |
| 7 | A-14 | D4   | Projected Cost of Preferred and Preference Stock  |
| 8 | A-18 | H1   | Current and Historical Credit Ratings             |
| 9 | A-18 | H2   | Recent Utility Corporate Bond Issuances           |

10

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

12 A10. Yes, they were.

13

14 **I. SUMMARY OF RECOMMENDATIONS**

15 **Q11. What permanent capital structure are you recommending for the projected**  
 16 **test year to be utilized in determining the overall rate of return calculation for**  
 17 **DTE Electric?**

18 A11. I am recommending a projected permanent capital structure of 49.25% long-term  
 19 debt and 50.75% common equity. Permanent capital refers to long-term perpetual  
 20 capital. Common equity, preferred stock and long-term debt are sources of  
 21 permanent capital. Since the Company does not have any preferred stock, I am  
 22 recommending the permanent capital structure to be made up of 49.25% long-term  
 23 debt and 50.75% common equity. This permanent capital structure is reflected in  
 24 DTE Electric's projected permanent capital structure as of December 31, 2026, as  
 25 shown in Exhibit A-14, Schedule D1, which is supported by Company Witness

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1 Vangilder. This capital structure is necessitated by the business and financial risks  
2 confronting DTE Electric, which I will discuss in greater detail later in my  
3 testimony.

4  
5 **Q12. What is your forecast for DTE Electric's cost of long-term debt, short-term**  
6 **debt, and preferred stock for the 12-month period ending December 31, 2026?**

7 A12. I am forecasting 4.24% for the cost of DTE Electric's long-term debt, and 4.75%  
8 for the cost of DTE Electric's short-term debt. The Company does not have  
9 preferred stock, and therefore it has no associated cost rate. Exhibit A-14, Schedule  
10 D2 supports the cost rate for long-term debt. Exhibit A-14, Schedule D3 supports  
11 the cost rate for short-term debt.

12

13 **II. DEVELOPMENT OF CAPITAL STRUCTURE**

14 **Q13. What do you mean by capital structure?**

15 A13. A company's capital structure includes the amount of equity and debt necessary to  
16 support the operations of its business and is defined differently by regulators,  
17 finance professionals, and rating agencies. Total regulatory capital structure  
18 typically includes long-term debt, short-term debt, preferred stock, common equity,  
19 deferred taxes, deferred job development investment tax credits, and deferred  
20 investment tax credits. Permanent capital structure includes only long-term debt  
21 and equity. Rating agencies calculate a company's capital structure using short-  
22 term debt, long-term debt, preferred stock, common equity, and other adjustments.  
23 The rating agencies adjust debt to include items like capital and operating leases,  
24 unfunded pension liabilities, power purchase agreements, and asset retirement  
25 obligations.

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1   **Q14. Why is a sound capital structure important?**

2   A14. It is important to have a financially sound capital structure to ensure that a company  
3       can obtain the necessary capital. A sound capital structure produces capital costs  
4       that are reasonable and equitable. Additionally, it is crucial that the overall return  
5       on capital be sufficient to assure financial confidence in a company and allow it to  
6       raise the funds necessary to operate its business at reasonable costs and terms. A  
7       sound capital structure is in the best interests of the customers as it ensures the  
8       continued viability of the company and provides access to capital at lower rates.

9  
10   **Q15. How does risk affect a company's capital structure?**

11   A15. In general, a company such as DTE Electric faces two types of risk: business risk  
12       and financial risk. Business risk is a result of both systemic and non-systemic risks.  
13       Systemic risks are broad economic risks faced by all companies, while non-  
14       systemic risks are specific to the individual company. Financial risk is the risk that  
15       common equity shareholders face when a company issues debt to finance real  
16       assets. Debtholders (also known as bondholders) have priority over equity  
17       shareholders in the event of corporate bankruptcy. Thus, the greater the amount of  
18       debt held by a company, the greater the risk to equity shareholders. It is essential  
19       that a company recognizes the dynamics of these risks and adjusts its underlying  
20       debt and equity components to produce a sound capital structure.

21

22   **Q16. How does a company's capital structure impact its ability to attract capital?**

23   A16. Having a weak or highly leveraged capital structure may lead to higher required  
24       returns on equity and a higher cost of debt. It also can impact the company's ability  
25       to obtain capital. For example, a company with a highly leveraged capital structure

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1 may lose its investment grade rating from the rating agencies. Non-investment  
2 grade companies have a limited investor base and a more limited access to capital  
3 than investment grade companies. Moreover, during periods of diminished capital  
4 liquidity, even investment grade companies can have limited access to new capital  
5 sources.

6

7 It is important to consider how extreme market reactions to singular events impact  
8 how easily capital can be accessed during the future test period should an  
9 unforeseen market shock occur. Furthermore, rating agencies allow little or no time  
10 for a company to correct and improve its capital structure before lowering its credit  
11 rating. Conversely, companies must be proactive in targeting and achieving the  
12 midpoint of the range of rating agency financial metrics to have a better chance of  
13 maintaining current ratings.

14

15 **Q17. Will higher debt levels in a capital structure affect the cost of debt?**

16 A17. Yes. The cost of debt increases as more debt is added to the capital structure.  
17 Further, higher debt levels can increase the risk of a downgrade by the rating  
18 agencies. A lower credit rating indicates greater credit risk such that investors will  
19 require a higher return to invest in a company. Consequently, this results in an  
20 increased cost of debt for that company.

21

22 **Q18. For DTE Electric's defined projected test year, what capital structure are you**  
23 **recommending for DTE Electric in the instant case?**

24 A18. For the projected test year, the permanent capital structure that I am recommending  
25 includes both long-term debt and equity as shown on Exhibit A-14, Schedule D1,

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1 that is supported by Witness Vangilder. Within this regulatory capital structure, I  
2 am recommending a projected test year permanent capital structure that has 49.25%  
3 long-term debt and 50.75% common equity.

4

5 **Q19. Is the proposed ratio of 50.75% common equity to total permanent**  
6 **capitalization in line with DTE Electric's peers?**

7 A19. No. The common equity ratio proposed in the instant case is lower than that of the  
8 Company's peers. To smooth the impact on customer affordability, the Company  
9 is proposing a measured increase to its current common equity ratio of 50%. As  
10 shown on Exhibit A-14 Schedule D1.1, the average equity ratio for DTE Electric  
11 peers is approximately 52%. DTE Electric's proposed 50.75% equity ratio is a  
12 reasonable level given that the average ratio of the peer group is higher at 52%.  
13 The data supporting this comparison was obtained from S&P Global Market  
14 Intelligence (SNL) for the most recent fiscal year available per peer company. DTE  
15 Electric believes its requested 50.75% is reasonable and below the equity ratio of  
16 its peers.

17

18 **Q20. Does the intense capital investment program contribute to the need for a**  
19 **higher level of equity in general within the capital structure?**

20 A20. Yes, it is crucial that DTE Electric be perceived as a financially sound company  
21 with a solid investment grade rating to ensure the reasonableness and  
22 competitiveness of capital costs. DTE Electric's plan is to finance and fund over  
23 \$7.9 billion of electric capital expenditures for the period January 2024 through  
24 December 2026 (see Exhibit A-12 Schedule B5). During periods of intense capital  
25 investment, maintaining a sound capital structure and a favorable regulatory

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1 environment is essential to the financial well-being of the Company. Should the  
2 Company face any unforeseen or negative impacts to its financial health, a higher  
3 equity balance may be necessary. The common equity balance and equity ratio  
4 projected for the test year in the instant case are intended to enable the Company to  
5 maintain strong credit ratings and withstand any financial market shocks, thereby  
6 ensuring a smooth implementation of its capital expenditure program.

7

8 **III. DEVELOPMENT OF COST RATES**

9 **Q21. What were DTE Electric's historical financial and ratemaking metrics from**  
10 **2019 through 2023?**

11 A21. DTE Electric's historical financial and ratemaking metrics for each of the previous  
12 five years (2019 through 2023) are detailed in Exhibit A-1, Schedule A2. The  
13 historical financial metrics include year-end financial data and are calculated based  
14 on DTE Electric's financial reports. The historical ratemaking metrics include year-  
15 end financial data and are calculated from DTE Electric's annual regulatory filings.

16

17 **Q22. What is the cost of long-term debt outstanding as of December 31, 2023?**

18 A22. Exhibit A-4, Schedule D2 calculates the cost of the long-term debt outstanding as  
19 of December 31, 2023. As shown in the exhibit and schedule, the cost of long-term  
20 debt also includes agent's fees, commissions, and financing expenses and is  
21 calculated on the net proceeds to the Company. The weighted average cost of debt  
22 is computed based on the total annual costs to the Company divided by the total  
23 principal amount outstanding at year-end. The cost of long-term debt as of  
24 December 31, 2023 was 3.95%.



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1 **Q23. What is the cost of short-term debt outstanding as of December 31, 2023?**

2 A23. The cost of short-term borrowings for the 13-month period ended December 31,  
3 2023 was 5.15%. The cost of short-term debt includes two components: 1) the  
4 interest rate on short-term borrowings, and 2) the credit facility fees associated with  
5 the credit agreements necessary for the issuance of short-term debt. Refer to Exhibit  
6 A-4, Schedule D3 for additional details.

7  
8 **Q24. What was the approved cost of equity as of December 31, 2023?**

9 A24. DTE Electric's authorized cost of common shareholders' equity as of December  
10 31, 2023 was 9.9% and was approved in Case No. U-21297. DTE Electric does not  
11 have any preferred stock. Refer to Exhibit A-4, Schedules D4 and D5 for additional  
12 details.

13  
14 **Q25. What does DTE Electric project its financial metrics to be in the projected test**  
15 **year?**

16 A25. DTE Electric's forecasted ratemaking metrics for the projected test year are detailed  
17 in Exhibit A-11, Schedule A2. These forecasted calculations include metrics for the  
18 fully projected test year. The forecasted ratemaking metrics for the projected test  
19 year are to be reported assuming (i) full rate relief as requested, and (ii) zero rate  
20 relief.

21  
22 **Q26. What is the purpose of Exhibit A-14, Schedule D2?**

23 A26. The purpose of Exhibit A-14, Schedule D2 is to calculate DTE Electric's projected  
24 weighted average long-term debt costs as of December 31, 2026. Starting with the  
25 actual December 31, 2023 long-term debt outstanding, any known and measurable

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changes for each year were made to arrive at the projected balance as of December 31, 2026. Known and measurable changes that have occurred or are projected to occur from January 1, 2024 through December 31, 2026 include:

**Table 1 Issuances and Redemptions**

| Long-Term Debt Activity | Amount<br>(\$000) | Date   | Interest<br>Rate |
|-------------------------|-------------------|--------|------------------|
| Issuance                | 500,000           | Mar-24 | 4.850%           |
| Issuance                | 500,000           | Mar-24 | 5.200%           |
| Redemption              | (100,000)         | Mar-24 | 3.650%           |
| Redemption              | (350,000)         | Mar-25 | 3.375%           |
| Issuance                | 621,000           | May-25 | 5.760%           |
| Issuance                | 800,000           | Mar-26 | 5.780%           |
| Redemption              | (100,000)         | Jun-26 | 3.770%           |
| Redemption              | (77,000)          | Sep-26 | 4.460%           |
| Redemption              | (500,000)         | Dec-26 | 4.850%           |
| Net change in debt      | 1,294,000         |        |                  |

For 2025 and 2026, the debt issuances are assumed to be 30-year fixed rate bonds with an interest rate of 5.76% and 5.78%, respectively. The interest rate for the debt issuances is based on forward 30-year Treasury rates and adding a spread of 119 basis points. The spread is the calculated 2-year historical average spread quoted by Scotiabank for the Company's 30-year debt issuance. Including the planned long-term debt issuance, the weighted average long-term debt cost as of December 31, 2026 is projected to be 4.24%.

**Q27. Why did you use long-term debt cost on a net proceeds basis?**

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1 A27. The actual costs would be understated if the net proceeds were not used in the base  
2 calculation. The net proceeds methodology accounts for underwriters'  
3 compensation and other financing expenses and is shown on Exhibit A-14,  
4 Schedule D2.

5  
6 A portion of any amount financed is used to fund these costs, such that the  
7 Company has access to less than the full amount financed. As a result, these fees  
8 and expenses are shown as a reduction in proceeds from the issuance of new  
9 securities, thereby increasing the effective cost of the issuance above the stated  
10 coupon rate

11

12 **Q28. How did you determine the interest rate on short-term debt on Exhibit A-14,**  
13 **Schedule D3?**

14 A28. The total cost of short-term debt is comprised of the interest rate on the short-term  
15 debt plus associated facility fees. Supporting credit facilities are required by the  
16 rating agencies and investors for DTE Electric to issue commercial paper. These  
17 facilities have costs associated with them. The interest rate on the short-term debt  
18 was determined by adding 20 basis points (bps) to the 1-month short-term index.  
19 Due to the uncertainty of interest rates and Fed Fund rate changes, the Company is  
20 using the short-term debt index and short-term debt rate in effect as of January  
21 2025. Interest rates have been very volatile recently with market uncertainty around  
22 when and if the Fed will lower the Fed Funds rate. Given this unpredictability, the  
23 Company feels it is prudent to use the current and known rate. A spread of 20 bps  
24 was added to the index because that is the current spread on DTE Electric's  
25 commercial paper issuances. See Exhibit A-14, Schedule D3.

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1 The current 1-month short-term index is 4.31%. Adding the spread of 20 bps to the  
2 index brings the interest rate on short-term borrowings to a total of 4.51%. The  
3 cost of the facility fees for the 12-month period ending December 31, 2026, is \$1.3  
4 million. This cost was divided by the average outstanding short-term debt balance  
5 of \$563 million and equates to 0.24% of the cost of short-term debt. Adding the  
6 interest rate on short-term debt of 4.51% to the facility fee cost of 0.24%, results in  
7 the total cost of short-term debt of 4.75%.

8

9 **Q29. What is the purpose of Exhibit A-14, Schedule D4?**

10 A29. Exhibit A-14, Schedule D4 shows that DTE Electric does not plan to have preferred  
11 or preference stock during the projected test period.

12

13 **Q30. What are the Company's current and historical credit ratings?**

14 A30. Exhibit A-18, Schedule H1 shows DTE Electric's and DTE Energy's current and  
15 historical credit ratings, along with associated rating agency outlooks, for the  
16 previous five years as published by Standard & Poor's (S&P), Moody's Investors  
17 Service (Moody's), and Fitch Ratings. The credit ratings include senior unsecured  
18 debt, senior secured debt, and commercial paper ratings.

19

20 **Q31. Have there been recent public utility bond issuances?**

21 A31. Yes. I have provided details of public utility bond issuances for the three-month  
22 period prior to, through the three-month period after, each of DTE Electric's long-  
23 term debt offerings issued during the 24 months prior to December of 2024. This  
24 summary includes the offer date, issuing company, type of offering (either secured

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1 or unsecured), Moody's and S&P credit ratings, maturity, tenor, amount of offering,  
2 coupon, and issue spread. See Exhibit A-18, Schedule H2.

3

4 **IV. SECURITIZATION**

5 **Q32. Does the Company intend to securitize additional regulatory assets?**

6 A32. Yes. On July 26, 2023, in Case No. U-21193, DTE Electric agreed to securitize a  
7 total of \$1.045 billion consisting of the Belle River coal handling assets and a  
8 portion of the net book value of Monroe Power Plant. The Company plans to  
9 submit a filing to securitize the net book balance associated with the Belle River  
10 coal handling assets and the previously approved tree trim regulatory assets in 2026.

11

12 **Q33. How has the tree trim surge regulatory asset been financed in prior rate cases?**

13 A33. On May 2, 2019, the Commission issued its order in Case No. U-20162 whereby  
14 the Company was authorized a return on the tree trim surge regulatory asset at the  
15 short-term debt cost rate of 3.56%. (p. 80). In Case No. U-20561, Case No. U-  
16 20836, Case No. U-21297, and Case No. U-21534 the return on tree trim surge  
17 regulatory asset was calculated at the authorized short-term debt rate.

18

19 **Q34. What does the Company believe is the appropriate financing rate for tree-trim  
20 assets?**

21 A34. Given the temporary status, defined in Case No. U-20162, of the tree trim surge  
22 regulatory asset, the Company did not pursue financing with permanent long-term  
23 debt and equity capital, but rather financed with short-term working capital  
24 including short-term debt. Thus, the financing costs matched with the return the  
25 Company was earning on the regulatory asset. In securitization Case No. U-21015

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1 and Case No. U-21338, the Commission considered the regulatory asset to have  
2 been financed with permanent capital and specified that proceeds of the  
3 securitization should be used for the repayment of long-term debt and equity.  
4 Consistent with that financing order, the Company's position is that any future tree  
5 trim surge regulatory asset amounts should be treated as being financed with  
6 permanent long-term debt and equity capital and receive the respective return.

7

8 **Q35. How does the Company propose to treat the tree trim surge regulatory asset**  
9 **in this instant case?**

10 A35. In Case No. U-21534, the Company reiterated its position that any future tree  
11 trimming surge expenditures be financed through the issuance of long-term debt  
12 and equity until the time the Company can execute a securitization financing for  
13 these amounts. I have directed Witness Vangilder to calculate the return on  
14 projected tree trim surge regulatory assets using the cost of permanent long-term  
15 debt and equity capital.

16

17 **V. Section 1706 Loan Program**

18 **Q36. What is the Title 17 Clean Energy Financing – Energy Infrastructure**  
19 **Reinvestment (EIR) Section 1706 Loan Program?**

20 A36. Created by the Inflation Reduction Act, EIR can help the United States leverage its  
21 extensive energy infrastructure and skilled workforce to support energy  
22 transformation. Under the EIR, the US Department of Energy (DOE) Loan  
23 Program Office (LPO) is administering the distribution of up to \$250 billion in loan  
24 guarantees under the Section 1706 Energy Infrastructure Reinvestment (EIR)  
25 program. The loan authority runs through September 30, 2026 (i.e., the DOE has

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1 until September 30, 2026 to commit the funds under its authority). Applications  
2 for EIR financing must fall into one or more of the following types of projects: 1)  
3 Projects that retool, repower, repurpose, or replace Energy Infrastructure that has  
4 ceased operations; 2) Projects that enable operating Energy Infrastructure to avoid,  
5 reduce, utilize, or sequester air pollutants or anthropogenic emissions of greenhouse  
6 gases. Electric utility borrowers for EIR projects must also demonstrate to the DOE  
7 that financial benefits received from the DOE loan guarantee will be passed on to  
8 the customers of, or communities served by, that utility.

9

10 **Q37. Has the Company received conditional commitment from the U.S. Department**  
11 **of Energy's Loan Program Office for Section 1706 funding?**

12 A37. Yes. The Company received a conditional commitment for a loan guarantee of up  
13 to \$7.2 billion on January 16, 2025. The next step is DOE and the company must  
14 satisfy certain technical, legal, environmental, and financial conditions before the  
15 Department enters into definitive financing documents and funds either loan. This  
16 assumes the Company can meet the conditions precedent for close which include,  
17 but are not limited to, approval by the US Department of Energy and Federal  
18 compliance, including with the National Environmental Policy Act (NEPA), the  
19 Davis-Bacon Act (DBA) and the Cargo Preference Act (CPA). The Company also  
20 anticipates incurring additional legal and due diligence costs at financial close.  
21 These costs will be included in the financing expenses associated with future loan  
22 advances.

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1   **Q38. What projects qualify under this program?**

2   A38. Through its due diligence approach to regulated utility lending, LPO confirms that  
3       one or more anchor projects meet program eligibility and environmental review  
4       requirements for inclusion in the guaranteed loan facility. The Company's anchor  
5       project for LPO funding is the Trenton Channel Battery Storage project. This  
6       project has an expected cost of \$410 million, though certain costs including  
7       allocated overhead are excluded from eligible costs. The Company may borrow up  
8       to 80% of eligible project costs after project in-service anticipated in December  
9       2026.

10

11   **Q39. What is a Federal Funding Compliance Management (FFCM) team?**

12   A39. FFCM team is a group of individuals responsible for the oversight, execution, and  
13       reporting of compliance with all DTE Electric Federal Grants and Loans.  
14       Specifically, they will assist with the extensive technical due diligence work related  
15       to Federal compliance including NEPA, the DBA and the CPA. The Company will  
16       be required to maintain compliance with these DOE regulations from the start of  
17       program eligibility (estimated to begin in 2025) through at least Q3 2031, and in  
18       some cases, through maturity of the loans in 2055.

19

20   **Q40. Does the 1706 Loan Funding Program benefit the Company's customers?**

21   A40. Yes, after accounting for closing fees and expenses and ongoing costs of  
22       compliance with Federal regulations, the loans will be funded with a discounted  
23       interest rate. This discounted rate will provide significant interest savings to the  
24       Company's customers through 2055. However, ultimate interest savings will  
25       depend on the future eligibility of projects for loan draws. Electric utility borrowers



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1 for EIR projects must also demonstrate to the DOE that financial benefits received  
2 from the DOE loan guarantee will be passed on to the customers of, or communities  
3 served by, that utility.

4

5 **VI. Investment Tax Credit (ITC)**

6 **Q41. Will you have Investment Tax Credits (ITC) eligible for transfer during the**  
7 **projected test period?**

8 A41. As discussed by Witness Wisniewski in her testimony, the 2022 Inflation Reduction  
9 Act (IRA) implemented ITC incentives related to qualifying battery storage  
10 facilities. The Company's Trenton Battery Storage Project is anticipated to qualify  
11 and generate ITCs in 2026. We expect the ITCs from this project will be transferred  
12 to an unrelated party in 2027.

13

14 **Q42. Why is it beneficial to customers to transfer these credits?**

15 A42. As explained by Witness Wisniewski, there are limits to how many tax credits can  
16 be utilized each year to reduce income taxes payable on a tax return. Given these  
17 limits, the Company is unable to utilize these credits for several years. If these  
18 credits are kept, customers will receive no cash benefit until these credits are  
19 utilized to reduce income taxes payable several years after the credits are generated.  
20 The ability to transfer tax credits enables customers to benefit from the quicker  
21 inflow of cash from the credit transfer. The cash from tax credit transfer essentially  
22 reduces the amount of debt and equity at DTE Electric. Lower debt and equity  
23 balances reduce the capital charges associated with those two funding sources,  
24 reducing customer revenue requirement on a net present value basis.

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1   **Q43. What amount is expected to be transferred and what is the discount rate?**

2   A43. The Company is expecting to transfer approximately \$131 million, as supported by  
3       Witness Wisniewski, at a projected discount rate of 5% that reflects monetization  
4       costs associated with the transfer. The Company has concluded that recovery of  
5       the discount through the over/under calculation is probable based upon the MPSC's  
6       approval of the amended Renewable Energy Plan (REP) No. U-21285 and further  
7       discussions with the MPSC staff.

8

9   **VII. SUMMARY AND CONCLUSIONS**

10   **Q44. Can you summarize your recommendation and conclusions?**

11   A44. Given the financial and business risks faced by the Company, a projected  
12       permanent capital structure of 49.25% long-term debt and 50.75% common equity  
13       is reasonable and prudent. DTE Energy has taken reasonable actions to strengthen  
14       DTE Electric's credit quality, including infusing over \$2.7 billion of common  
15       equity from 2019 through 2023 and will continue to do so as needed. The plan calls  
16       for additional equity infusions and retained earnings growth through the projected  
17       test period in the amount necessary to maintain the Company at no less than a ratio  
18       of 50.75% equity to permanent capital at December 31, 2026. For the projected  
19       year, the cost of short-term debt is projected to be 4.75%, and the cost of long-term  
20       debt is projected to be 4.24%. I believe these expenses and measures are  
21       reasonable, prudent and necessary.

22

23   **Q45. Does this complete your direct testimony?**

24   A45. 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-21860

QUALIFICATIONS  
  
AND  
  
DIRECT TESTIMONY  
  
OF  
  
JENNIFER E. NELSON

**DTE ELECTRIC COMPANY**  
**QUALIFICATIONS AND DIRECT TESTIMONY OF JENNIFER E. NELSON**

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1     **Q1.    What is your name, business address, and occupation?**

2     A1.    My name is Jennifer E. Nelson.  My business address is 293 Boston Post Road  
3            West, Suite 500, Marlborough, Massachusetts, 01752.  I am a Vice President at  
4            Concentric Energy Advisors (“Concentric”).  Concentric is a management  
5            consulting and economic advisory firm that specializes in the North American  
6            energy and water industries.  Based in Marlborough, Massachusetts and  
7            Washington, D.C., Concentric specializes in regulatory and litigation support,  
8            financial advisory services, energy market strategies, market assessments, energy  
9            commodity contracting and procurement, economic feasibility studies, and capital  
10          market analyses.

11

12    **Q2.    On whose behalf are you testifying?**

13    A2.    I am testifying on behalf of DTE Electric Company (“DTE Electric” or the  
14            “Company”).

15

16    **Q3.    What is your educational background?**

17    A3.    I have a Bachelor of Science degree in Business Economics from Bentley  
18            University and a Master of Science in Resource and Applied Economics from the  
19            University of Alaska.

20

21    **Q4.    What is your work experience?**

22    A4.    I have more than fifteen years of experience in the energy industry, having served  
23            as a consultant and energy/regulatory economist for state government agencies.  
24            Since 2013, I have provided consulting services to clients on a range of financial  
25            and regulatory issues including cost of capital, ratemaking policy, and regulatory

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1 strategy issues. Prior to consulting, I was a staff economist at the Massachusetts  
2 Department of Public Utilities and a petroleum economist for the State of Alaska.  
3 I completed utility regulatory training offered by New Mexico State University's  
4 Center for Public Utilities. A summary of my professional and educational  
5 background, including a list of my testimony filed before regulatory commissions,  
6 is included as Exhibit A-14 Schedule D5.

7

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

10 A5. Yes. I am a member of the Society of Utility and Regulatory Financial Analysts  
11 and earned the Certified Rate of Return Analyst designation based on my  
12 experience and successful completion of an examination.

13

14 **Q6. Have you previously submitted testimony before the Michigan Public Service**  
15 **Commission ("MPSC" or "Commission")?**

16 A6. No, I have not submitted testimony before the Commission. However, I have  
17 previously filed testimony before regulatory commissions in Arkansas, California,  
18 Delaware, Florida, Kentucky, Maine, Montana, New Hampshire, New Mexico,  
19 North Carolina, Ohio, Oklahoma, Oregon, South Carolina, Utah, Virginia, West  
20 Virginia, and Wyoming. During my time as a consultant, I have supported the  
21 development of expert witness testimony and analyses regarding the Return on  
22 Equity ("ROE") and capital structure in more than 100 proceedings filed before  
23 numerous U.S. state regulatory commissions and the Federal Energy Regulatory  
24 Commission.

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1     **I.     Purpose of Testimony**

2     **Q7.     What is the purpose of your testimony?**

3     A7.     The purpose of my direct testimony is to present evidence and provide the  
4             Commission with a recommendation regarding DTE Electric's return on equity  
5             ("ROE") and to evaluate the reasonableness of its requested capital structure.  
6

7     **Q8.     Are you sponsoring any exhibits in this proceeding?**

8     A8.     Yes. I am sponsoring the following exhibits:

| 9  | <u>Exhibit</u> | <u>Schedule</u> | <u>Description</u>                                 |
|----|----------------|-----------------|----------------------------------------------------|
| 10 | Exhibit A-14   | D5              | Résumé and Testimony Listing of Jennifer E. Nelson |
| 11 | Exhibit A-14   | D5.1            | Constant Growth DCF Results                        |
| 12 | Exhibit A-14   | D5.2            | Quarterly Growth DCF Results                       |
| 13 | Exhibit A-14   | D5.3            | Expected Market Return Calculations                |
| 14 | Exhibit A-14   | D5.4            | CAPM and Empirical CAPM Results                    |
| 15 | Exhibit A-14   | D5.5            | Bond Yield Plus Risk Premium Analysis              |
| 16 | Exhibit A-14   | D5.6            | Capital Expenditure Analysis                       |
| 17 | Exhibit A-14   | D5.7            | Proxy Group Clean Energy Standard and Renewable    |
| 18 |                |                 | Portfolio Standard Comparison                      |
| 19 | Exhibit A-14   | D5.8            | Regulatory Risk                                    |

20

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

22    A9.     Yes, they were.

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1     **II.     Summary and Overview of Testimony**

2     **Q10.   What are your conclusions regarding the appropriate cost of equity and**  
3           **capital structure for the Company?**

4     A10.   Based on my analyses using three widely used market-based financial models, the  
5           Company's risk profile, and the current capital market environment, I conclude that  
6           a range of 9.90 percent to 11.60 percent reflects investors' required return for an  
7           equity investment in DTE Electric. Within that range, I recommend an ROE of  
8           10.75 percent, which is the midpoint of the range.

9  
10          As to the capital structure, I conclude the Company's requested permanent capital  
11          structure consisting of 50.75 percent common equity, 49.25 percent long-term debt  
12          is reasonable, consistent with industry practice, and should be approved.

13  
14     **Q11.   Please provide a brief overview of the analyses that led to your ROE**  
15           **determination.**

16     A11.   My recommendation is developed using three widely accepted financial modeling  
17           approaches applied to a proxy group of 19 electric utility companies: (1) the  
18           constant growth and quarterly growth forms of the Discounted Cash Flow ("DCF")  
19           model; (2) the traditional and empirical forms of the Capital Asset Pricing Model  
20           ("CAPM"); and (3) the Bond Yield Plus Risk Premium approach. The results of  
21           those analytical approaches are summarized in Table 1 below.

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**Table 1 Summary of Results**

| <b>Constant Growth DCF</b>                 | <b>Low</b> | <b>Mean</b>                                   | <b>High</b>                                     |
|--------------------------------------------|------------|-----------------------------------------------|-------------------------------------------------|
| 30-Day Average                             | 9.54%      | 10.32%                                        | 11.01%                                          |
| 90-Day Average                             | 9.42%      | 10.27%                                        | 10.91%                                          |
| 180-Day Average                            | 9.59%      | 10.40%                                        | 11.06%                                          |
| <b>Quarterly Growth DCF</b>                | <b>Low</b> | <b>Mean</b>                                   | <b>High</b>                                     |
| 30-Day Average                             | 9.76%      | 10.56%                                        | 11.29%                                          |
| 90-Day Average                             | 9.63%      | 10.52%                                        | 11.20%                                          |
| 180-Day Average                            | 9.81%      | 10.68%                                        | 11.34%                                          |
|                                            |            |                                               |                                                 |
| <b>CAPM</b>                                |            | <b>Current 30-Year Treasury Yield (4.82%)</b> | <b>Projected 30-Year Treasury Yield (4.46%)</b> |
| Long-Term Historical Average Market Return |            | 11.54%                                        | 11.51%                                          |
| DCF-based Expected Market Return           |            | 14.39%                                        | 14.36%                                          |
| <b>Empirical CAPM</b>                      |            | <b>Current 30-Year Treasury Yield (4.82%)</b> | <b>Projected 30-Year Treasury Yield (4.46%)</b> |
| Long-Term Historical Average Market Return |            | 11.70%                                        | 11.68%                                          |
| DCF-based Expected Market Return           |            | 14.61%                                        | 14.59%                                          |
|                                            |            |                                               |                                                 |
| <b>Bond Yield Plus Risk Premium</b>        |            |                                               |                                                 |
| Current 30-Year Treasury Yield (4.82%)     |            | 10.37%                                        |                                                 |
| Projected 30-Year Treasury Yield (4.46%)   |            | 10.20%                                        |                                                 |
|                                            |            |                                               |                                                 |
| Average Mean DCF                           |            | 10.46%                                        |                                                 |
| Average Low CAPM                           |            | 11.61%                                        |                                                 |
| Average Risk Premium                       |            | 10.28%                                        |                                                 |
| 3-Model Average                            |            | 10.78%                                        |                                                 |



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1   **Q12. How do you determine your recommended range from the methods and**  
2       **results summarized above?**

3   A12. The cost of equity is an opportunity cost that cannot be precisely quantified.  
4       Therefore, it must be estimated through various financial models. Each of the ROE-  
5       estimation models is subject to limiting assumptions and each provides a different  
6       perspective on investors' return requirements under varying market conditions. The  
7       use of multiple financial models, therefore, enables a more robust and  
8       comprehensive assessment of the cost of equity instead of relying on one specific  
9       estimation model.

10

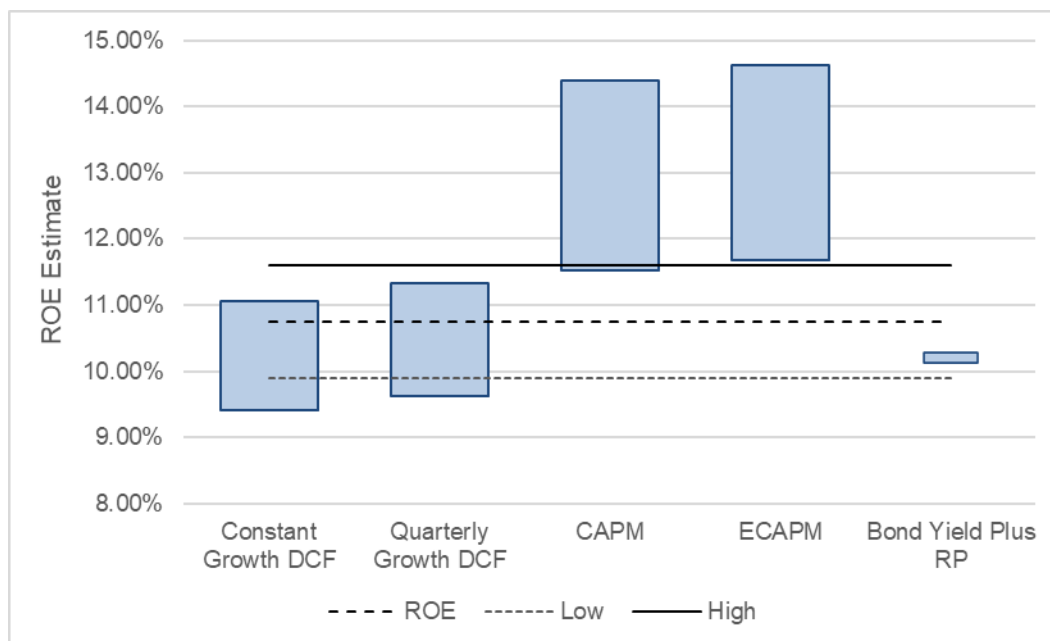
11       After reviewing the model results shown above in Table 1, I assess the Company's  
12       risk profile relative to a group of proxy companies. As explained in more detail  
13       throughout my testimony, my recommendation considers: (1) the Company's  
14       significant capital investment needs; (2) the effect of Michigan's clean energy  
15       mandates; (3) the regulatory environment in which the Company operates; (4) DTE  
16       Electric's financial risk reflected in its capital structure; and (5) the current capital  
17       market environment. Although those factors are relevant to investors, their effect on  
18       the Company's cost of equity cannot be directly quantified. While I do not make  
19       any explicit adjustments to my ROE estimates for DTE Electric's business risks, I  
20       consider them when determining my ROE recommendation.

21

22       The low end of my range, 9.90 percent, is within the range of the low and mean DCF  
23       results. The high end of my recommended range, 11.60 percent, is within the range  
24       of the low end of my CAPM results (see Figure 1 below).

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1 **Figure 1. Range of ROE Estimate Model Results and Recommendation**



2  
3 Based on those considerations, it is my opinion that the midpoint of the range, or  
4 10.75 percent, is a reasonable estimate of DTE Electric's cost of equity. As Table  
5 1 above shows, my 10.75 percent ROE recommendation is approximately equal to  
6 the average of the mean DCF results, the low CAPM results, and the Risk Premium  
7 results.

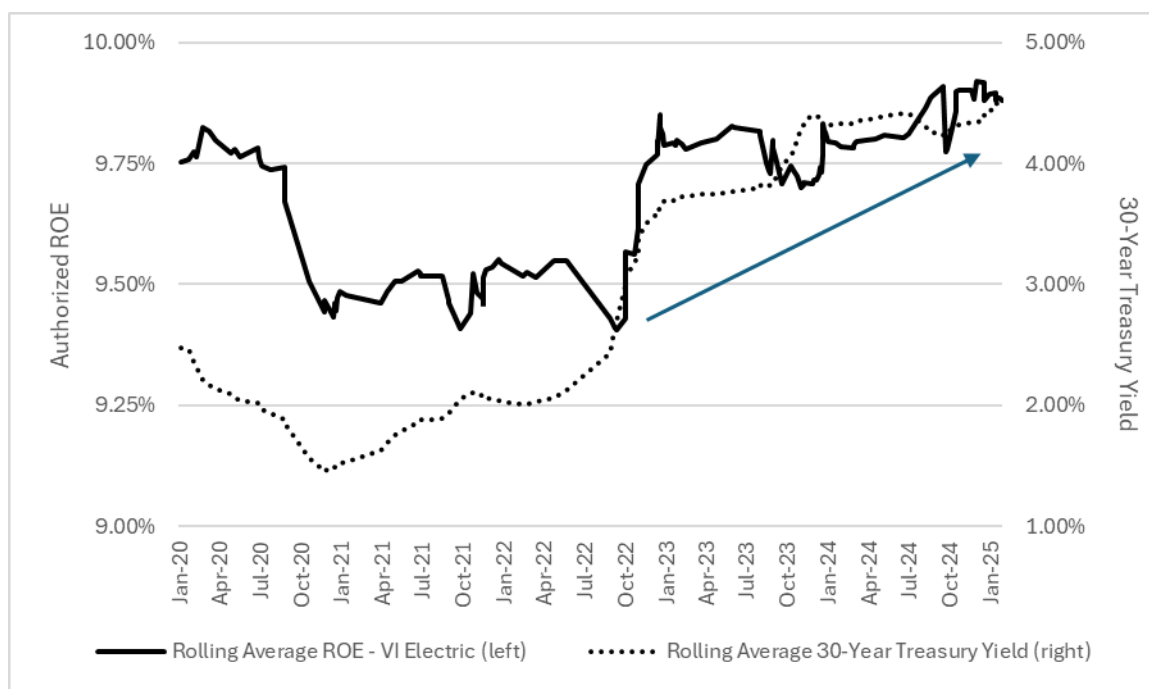
8  
9 **Q13. Have authorized returns for vertically integrated electric utilities increased**  
10 **with higher bond yields?**

11 A13. Yes. Prevailing long-term bond yields have a significant impact on utilities' cost of  
12 capital, as well as investors' assessment of fair and reasonable return on invested  
13 capital. For example, rising treasury yields signal to investors that they can earn a  
14 higher return investing in risk-free government bonds. Consequently, equity  
15 investors will expect higher returns for riskier securities such as utility equities as  
16 government bond yields rise. As shown in Figure 2, regulators have acknowledged

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1 rising capital costs in their ROE decisions, albeit in a lagged fashion. On a nine-  
2 month rolling average basis,<sup>1</sup> the average authorized ROEs for vertically integrated  
3 electric utilities have increased to 9.88 percent as of January 31, 2025.

4  
5 **Figure 2. Authorized Returns for Vertically Integrated Utilities**  
6 **vs. 30-Year U.S. Treasuries (rolling average 2020-2025)<sup>2</sup>**



7  
8 **Q14. How is the remainder of your testimony organized?**

9 A14. The remainder of my Direct Testimony is organized as follows:

- 10 • Section III – Provides a summary of issues regarding the cost of equity  
11 estimation in regulatory proceedings, describes the regulatory guidelines  
12 pertinent to the development of the cost of capital, explains my selection of

1 A nine-month rolling average captures the length of the average rate case.

2 Source: Regulatory Research Associates, as of January 31, 2025.

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- 1 the proxy group used to develop my analytical results, and describes the
- 2 analyses on which my ROE determination is based;
- 3 • Section IV – Discusses the specific business risks that have a direct bearing
- 4 on the Company’s cost of equity;
- 5 • Section V – Assesses the Company’s requested capital structure;
- 6 • Section VI – Reviews the current capital market conditions and the effect on
- 7 the cost of equity; and
- 8 • Section VII – Summarizes my conclusions and recommendations.

9

10 **III. Cost of Equity Estimation**

11 Regulatory Guidelines and Financial Considerations

12 **Q15. Before addressing the specific aspects of this proceeding, please explain the**

13 **connection between the cost of capital and a utility’s cost of service.**

14 A15. Under the cost-of-service ratemaking paradigm, the development of utility rates

15 begins with determining the utility’s total cost to serve customers. This is known

16 as the revenue requirement, since the utility’s revenues must be sufficient to recover

17 its costs to serve customers. The revenue requirement consists of four components:

18 (1) operating and maintenance (“O&M”) expenses, (2) taxes, (3) the return of

19 capital through depreciation expense, and (4) the return on capital through the

20 regulated return on rate base. The return on rate base is calculated as the weighted

21 average cost of capital multiplied by the rate base. The return on capital must be

22 sufficient to allow the utility to repay its debt obligations and compensate equity

23 investors for the use of their financial capital. From that important perspective, the

24 return on capital reflects a cost to the utility just like any other component of the

25 revenue requirement.

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1 **Q16. Please explain the cost of capital conceptually.**

2 A16. The cost of capital is the return that investors require to commit capital to a  
3 company. Investors will provide funds to a company only if the return that they  
4 expect is equal to, or greater than, the return that they require to accept the risk of  
5 investing capital in the company. Simply, the cost of capital is the expected rate of  
6 return prevailing in the capital markets on alternative investments of similar risk.<sup>3</sup>  
7 Conceptually, the cost of capital is: (1) forward looking and reflects an expected  
8 rate of return; (2) an opportunity cost; (3) determined in the capital markets, and  
9 (4) dependent on, and proportional to, the risk of the investment.<sup>4</sup>

10

11 Because the cost of equity is expectational and premised on the principle of  
12 opportunity costs, it cannot be precisely quantified. Instead, it must be estimated by  
13 applying market data to various financial models that are simplified representations  
14 of investor behavior and expectations. Moreover, equity investors have a  
15 subordinate claim to cash flows owed to debt investments and other claims; the  
16 uncertainty (or risk) associated with those residual cash flows determines the cost  
17 of equity. In the end, the cost of equity should reflect the return that investors require  
18 considering the subject company's risk profile and the returns available on  
19 comparable investments.

20

21 **Q17. How is the Cost of Equity estimated in regulatory proceedings?**

22 A17. Regulated utilities primarily use long-term capital (e.g., common stock and long-  
23 term debt) to finance their permanent rate base. The rate of return for a regulated

---

3 Lawrence A. Kolbe, James A. Read, Jr., and George R. Hall, The Cost of Capital – Estimating the Rate of Return for Public Utilities, The MIT Press, Cambridge, MA, at 13 (1985).

4 Lawrence A. Kolbe, James A. Read, Jr., and George R. Hall, The Cost of Capital – Estimating the Rate of Return for Public Utilities, The MIT Press, Cambridge, MA, at 13 (1985).

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1 utility is calculated as its weighted average cost of capital, in which the costs of the  
2 individual sources of capital are weighted by their respective book values.

3

4 The ROE reflects the cost of raising and retaining equity capital and is estimated by  
5 using one or more market-based analytical approaches. Although quantitative  
6 models are used to estimate the ROE, the cost of equity cannot be precisely  
7 quantified through a strict mathematical exercise. As such, a reasonable and  
8 appropriate ROE reflects the financial, economic, and regulatory environment in  
9 which the estimate is developed, as well as the subject company's risk profile.

10

11 **Q18. Please briefly summarize the guidelines used to establish the cost of capital for**  
12 **a regulated utility.**

13 A18. Public utility regulation is rooted in the principle that utilities receive a fair rate of  
14 return sufficient to attract the capital required to provide safe and reliable public  
15 utility service for customers at reasonable rates. The U.S. Supreme Court  
16 ("Supreme Court") established the guiding principles for establishing a fair return  
17 for capital in two seminal cases: (1) *Bluefield Water Works and Improvement Co.*  
18 *v. Public Service Comm'n.* ("Bluefield");<sup>5</sup> and (2) *Federal Power Comm'n v. Hope*  
19 *Natural Gas Co.* ("Hope").<sup>6</sup> In *Bluefield*, the Court stated:

20 *A public utility is entitled to such rates as will permit it to earn a return*  
21 *upon the value of the property which it employs for the convenience of*  
22 *the public equal to that generally being made at the same time and in the*  
23 *same general part of the country on investments in other business*  
24 *undertakings which are attended by corresponding risks and*  
25 *uncertainties; but it has no constitutional right to profits such as are*  
26 *realized or anticipated in highly profitable enterprises or speculative*

---

5 *See, Bluefield Water Works and Improvement Co. v. Public Service Comm'n.*, 262 U.S. 679, 692 (1923).

6 *See, Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

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1        *ventures. The return should be reasonably sufficient to assure*  
2        *confidence in the financial soundness of the utility and should be*  
3        *adequate, under efficient and economical management, to maintain and*  
4        *support its credit, and enable it to raise the money necessary for the*  
5        *proper discharge of its public duties.*<sup>7</sup>

6        The Supreme Court therefore recognized that: (1) a regulated public utility cannot  
7        remain financially sound unless the return it is allowed to earn on its invested capital  
8        is at least equal to the cost of capital (the principle relating to the demand for capital);  
9        and (2) a regulated public utility will not be able to attract capital if it does not offer  
10       investors an opportunity to earn a return on their investment equal to the return they  
11       expect to earn on other investments of similar risk (the principle relating to the  
12       supply of capital).

13

14       In *Hope*, the Supreme Court reiterated the three primary standards for a regulated  
15       rate of return:

16       *From the investor or company point of view it is important that there be*  
17       *enough revenue not only for operating expenses but also for the capital*  
18       *costs of the business. These include service on the debt and dividends*  
19       *on stock...By that standard the return to the equity owner should be*  
20       *commensurate with returns on investments in other enterprises having*  
21       *corresponding risks. That return, moreover, should be sufficient to*  
22       *assure confidence in the financial integrity of the enterprise, so as to*  
23       *maintain its credit and to attract capital.*<sup>8</sup>

24       In summary, the Supreme Court has recognized that the fair return should be: (1)  
25       commensurate with returns investors expect to earn on other investments of similar  
26       risk (the “comparable risk” standard); (2) sufficient to assure confidence in the  
27       company’s financial integrity (the “financial integrity” standard); and (3) adequate  
28       to maintain and support the company’s credit and to attract capital (the “capital

---

7       *Bluefield Water Works and Improvement Co. v. Public Service Comm’n.*, 262 U.S. 679, 692  
      (1923).

8       *Federal Power Comm’n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

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1 attraction” standard). Importantly, a fair and reasonable rate of return satisfies all  
2 three standards.

3

4 **Q19. Has the Commission also applied the *Hope* and *Bluefield* standards as**  
5 **guidance for setting rates?**

6 A19. Yes. For example, in its Order in Case No. U-21534, the Commission stated:

7 *The criteria for establishing a fair ROE for public utilities is rooted in*  
8 *the language of the landmark United States Supreme Court cases*  
9 *Bluefield Waterworks & Improvement Co v Pub Serv Comm of West*  
10 *Virginia, 262 US 679; 43 S Ct 675; 67 L Ed 1176 (1923) and Fed Power*  
11 *Comm v Hope Natural Gas Co, 320 US 591; 64 S Ct 281; 88 L Ed 333*  
12 *(1944).*<sup>9</sup>

13 Additionally, the Commission recognized that the determination of a fair and  
14 reasonable ROE “is not subject to mathematical computation with scientific  
15 exactitude but depends on a comprehensive examination of all factors involved  
16 having in mind the objective sought to be attained in its use.”<sup>10</sup>

17

18 Based on those standards, the authorized ROE should provide DTE Electric with the  
19 *opportunity* to earn (which is not a guarantee) a fair and reasonable return and should  
20 enable efficient access to external capital under a variety of market conditions.

21

22 **Q20. Why is it important for a utility to be allowed a reasonable opportunity to earn**  
23 **a return that is adequate to attract capital?**

24 A20. Regulated utilities have a legal obligation to serve regardless of prevailing  
25 economic and capital market conditions. Unlike non-regulated companies, a

---

9 Case No. U-21534, Order, at 200 (January 23, 2025).

10 Case No. U-21534, Order, at 200 (January 23, 2025), *citing, Meridian Twp v City of East Lansing, 342 Mich 734, 749; 71 NW2d 234 (1955).*



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1 regulated utility cannot decide to whom it provides utility service in its service  
2 territory, how much service it delivers, nor when it provides service. Non-regulated  
3 companies can time investments to coincide with favorable market conditions and  
4 defer investments when markets are constrained and economic conditions are  
5 unfavorable. Utilities have limited options to do so. Therefore, utilities must  
6 ensure they have access to external financial capital on cost effective and favorable  
7 terms not only during times when markets are well-behaving, but also when  
8 markets are volatile or constrained (e.g., during periods of high inflation and  
9 interest rates, global pandemics, changes in government, and economic recessions).  
10 Capital is finite and the Company competes for capital among other utilities and  
11 other investment opportunities. A return that is adequate to attract capital at  
12 reasonable terms enables the utility to provide safe and reliable service while  
13 maintaining its financial integrity. As discussed above, and in keeping with the  
14 *Hope* and *Bluefield* standards, that return must be commensurate with the returns  
15 expected for investments of comparable risk.

16

17 The ratemaking process is based on the principle that, for investors and companies  
18 to commit the capital needed to provide safe and reliable utility services, the utility  
19 must have a reasonable opportunity to recover the return of, and the market-required  
20 return on, invested capital. To meet the legal obligation to serve, the allowed ROE  
21 should enable the subject utility to maintain its financial integrity in a variety of  
22 economic and capital market conditions. To preserve and enhance service  
23 reliability, DTE Electric must generate adequate cash flow from operations and have  
24 efficient access to external capital needed to undertake its capital investment plan  
25 regardless of the economic and capital market conditions at the time.

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1 Further, the financial community carefully monitors utility companies' current and  
2 expected financial conditions, as well as the regulatory environment in which those  
3 companies operate. In that respect, the regulatory environment is one of the most  
4 important factors considered in both debt and equity investors' assessments of risk.<sup>11</sup>  
5 That consideration is especially important during uncertain economic and financial  
6 conditions in which the utility may require access to capital markets.

7

8 The outcome of the Commission's order in this case, therefore, should provide DTE  
9 Electric with the opportunity to earn an ROE that is: (1) adequate to attract capital  
10 at reasonable terms, (2) sufficient to ensure its financial integrity, and (3)  
11 commensurate with returns on investments in enterprises having corresponding  
12 risks. To the extent DTE Electric has a reasonable opportunity to earn its market-  
13 based cost of equity, neither customers nor shareholders are disadvantaged. In fact,  
14 a return that is adequate to attract capital at reasonable terms enables DTE Electric  
15 to provide customers with safe, reliable service while maintaining its financial  
16 integrity.

17

18 **Q21. Do customers benefit from a utility with a strong financial profile?**

19 A21. Yes, very much so. For customers to receive safe and reliable electric service each  
20 and every day, utilities must continuously invest in their systems (e.g., to meet  
21 customer demand, replace aging infrastructure, and improve reliability and  
22 resiliency), which requires ongoing access to external sources of financial capital.  
23 Utilities with strong financial profiles are able to access capital on cost-effective  
24 and favorable terms for customers' benefit over the long term. Utilities compete

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11 *See, e.g.,* Moody's Investors Service, Rating Methodology: Regulated Gas and Electric Utilities, at 7 (August 6, 2024).

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1 for capital among other utilities and rational investors will choose to invest in  
2 utilities that offer the best comparable return opportunities, including a reasonable  
3 dividend to shareholders. Further, capital markets are unpredictable, and  
4 exogenous events beyond a utility's control may constrain access to capital, or  
5 result in significantly higher capital costs at less favorable terms. A utility with a  
6 stronger financial profile has a higher likelihood of withstanding adverse  
7 exogenous events and accessing capital at favorable terms for customers. As a  
8 utility's financial profile weakens, its credit profile degrades, its risk increases, and  
9 the cost of capital (both debt and equity) increases. Fewer investors may be willing  
10 to commit capital as risk increases and those that are willing may require more  
11 onerous terms at higher costs to customers' detriment. In the end, customers expect  
12 reliable service and DTE Electric is obligated to meet customers' energy demand  
13 regardless of the capital market and economic environment. Therefore, customers'  
14 long-term interests are best served by ensuring DTE Electric has a strong financial  
15 profile that will enable it to access the capital on cost effective and favorable terms  
16 to meet its obligation to serve.

17

18 **Q22. Are you aware of circumstances in which access to capital became constrained**  
19 **even for utilities with an investment grade credit rating?**

20 A22. Yes. For example, a 2009 report by the Edison Electric Institute ("EEI") entitled  
21 "The Financial Crisis and Its Impact on the Electric Utility Industry" discussed the  
22 effect of the 2008 Financial Crisis on utilities' ability to access capital. EEI noted  
23 that Lehman Brothers had been a major issuer of commercial paper and when it  
24 collapsed, "the commercial paper market literally evaporated."<sup>12</sup> EEI also observed

---

12 Edison Electric Institute, "The Financial Crisis and Its Impact on the Electric Utility Industry," at 5 (February 2009).

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1 that spreads for electric utility debt increased significantly, several hundred basis  
2 points above their normal ranges.<sup>13</sup> Utilities with credit ratings in the “A” range  
3 were generally able to secure long-term debt at lower premiums than utilities with  
4 “BBB” credit ratings, saving customers more than 100 basis points per year in debt  
5 costs on average. The report further explained that equity financing was also  
6 difficult to secure during that time.<sup>14</sup> Given the obligation to serve and continuous  
7 need to access capital, utilities must be prepared for such events that may occur  
8 beyond their control.

9

10 **Q23. What are your conclusions regarding the regulatory principles pertaining to**  
11 **the cost of capital for a public utility?**

12 A23. Congruent with other costs in a utility’s cost of service, the regulated return on rate  
13 base is a cost that DTE Electric incurs as part of its normal operations, including  
14 the need to compensate equity investors for the use of their capital. Under the *Hope*  
15 and *Bluefield* standards, the cost of equity authorized for DTE Electric in this  
16 proceeding should be: (1) adequate to attract capital at reasonable terms;  
17 (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on  
18 investments having similar risks.

19

20 Because utilities are capital intensive and investors have many investment  
21 alternatives, the Company’s financial profile must be adequate on a relative basis to  
22 ensure its ability to attract capital under a variety of economic and financial market

---

13 Edison Electric Institute, “The Financial Crisis and Its Impact on the Electric Utility Industry,” at 5-6 (February 2009).

14 Edison Electric Institute, “The Financial Crisis and Its Impact on the Electric Utility Industry,” at 7 (February 2009).

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1 conditions. The Commission’s decision regarding the authorized ROE and capital  
2 structure in this proceeding will directly affect the Company’s ability to attract the  
3 capital needed to maintain and enhance service to customers.

4

5 Proxy Group Selection

6 **Q24. Why is it necessary to select a group of proxy companies to determine the cost**  
7 **of equity for DTE Electric?**

8 A24. Because the ROE is a market-based concept, and DTE Electric is not a separate  
9 entity with its own stock price, it is necessary to establish a group of companies that  
10 are both publicly traded and generally comparable to the Company in certain  
11 fundamental respects to serve as its “proxy” in the ROE estimation process. Even  
12 if the Company were a publicly traded entity, short-term events could bias its  
13 market value during a given time period. A significant benefit of using a proxy  
14 group is that it moderates the effects of anomalous, temporary events associated  
15 with any one company.

16

17 **Q25. Please provide a summary profile of DTE Electric.**

18 A25. DTE Electric is an indirect wholly owned subsidiary of DTE Energy. DTE Electric  
19 is engaged in the generation, purchase, distribution, and sale of electricity to  
20 approximately 2.3 million customers in southeastern Michigan.<sup>15</sup> The Company’s  
21 generation fleet consists primarily of two coal-fired plants, a combined cycle  
22 natural gas plant, a hydroelectric pumped storage plant, a nuclear plant, and wind  
23 and solar assets.<sup>16</sup>

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15 DTE Energy SEC Form 10-K, at 6 (December 31, 2024).

16 DTE Energy SEC Form 10-K, at 7 (December 31, 2024).

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The Company's current long-term issuer credit ratings are as follows:

**Table 2      DTE Electric's Long-Term Issuer Credit Ratings**

| <b>Rating Agency</b>                  | <b>Current Credit Rating</b> | <b>Outlook</b> |
|---------------------------------------|------------------------------|----------------|
| S&P Global Ratings ("S&P")            | BBB+                         | Stable         |
| Moody's Investors Service ("Moody's") | A2                           | Stable         |
| Fitch Ratings ("Fitch")               | A-                           | Stable         |

**Q26. What criteria do you use to select the proxy group?**

A26. Because estimating the cost of equity is a comparative exercise, it is necessary to develop a proxy group of companies with risk profiles that are reasonably comparable to the subject company. As each company is unique, no two companies will have identical business and financial risk profiles. In selecting a proxy group, my objective is to balance the competing interests of selecting companies that are representative of the risks and prospects faced by DTE Electric, while at the same time ensuring that there is a sufficient number of companies in the proxy group. To develop my proxy group, I begin with the U.S. companies that *Value Line* classifies as Electric Utilities, and applied the following screening criteria:

- Because certain models used in my analyses assume that earnings and dividends grow over time, I exclude companies that do not consistently pay quarterly cash dividends, or have cut their dividend in the last two years;
- Because certain models assume that earnings grow over time, I exclude companies that do not have positive earnings growth rates from at least two sources;

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- 1           • To ensure that the growth rates used in my analyses are not biased by a single
- 2           analyst, all the companies in my proxy group are consistently covered by at
- 3           least two utility industry equity analysts;
- 4           • Because DTE Electric is a vertically integrated electric utility (i.e., owns and
- 5           operates regulated generation in addition to distribution assets), I exclude
- 6           companies that are not vertically integrated;
- 7           • I exclude companies that do not have (or its primary regulated electric utility
- 8           subsidiary does not have) an investment-grade corporate or senior unsecured
- 9           bond credit rating from S&P and Moody's;
- 10          • To incorporate companies that are primarily regulated electric utilities, I first
- 11          exclude companies that have less than 60.00 percent of net operating income
- 12          from regulated operations. I then exclude companies within this group that
- 13          have less than 60.00 percent of total regulated operating income from
- 14          regulated electric operations, on average, over the last three years; and
- 15          • I eliminate companies that have had significant merger activity or
- 16          transactions or have had a recent financial event that could affect their
- 17          market data or financial condition.

18

19   **Q27. What companies meet your screening criteria?**

20   A27. The criteria discussed above result in a proxy group of the following 19 companies:

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1

**Table 3 Proxy Group Screening Results**

| <b>Company</b>                        | <b>Ticker</b> |
|---------------------------------------|---------------|
| Alliant Energy Corporation            | LNT           |
| Ameren Corporation                    | AEE           |
| American Electric Power Company, Inc. | AEP           |
| Avista Corporation                    | AVA           |
| CMS Energy Corporation                | CMS           |
| Duke Energy Corporation               | DUK           |
| Entergy Corporation                   | ETR           |
| Evergy, Inc.                          | EVERG         |
| FirstEnergy Corporation               | FE            |
| IDACORP, Inc.                         | IDA           |
| NextEra Energy, Inc.                  | NEE           |
| NorthWestern Energy Group, Inc.       | NWE           |
| OGE Energy Corp.                      | OGE           |
| Pinnacle West Capital Corporation     | PNW           |
| Portland General Electric Company     | POR           |
| PPL Corporation                       | PPL           |
| Southern Company                      | SO            |
| TXNM Energy                           | TXNM          |
| Xcel Energy Inc.                      | XEL           |

2

3 The screening criteria results in a group of electric utilities that are comparable (but  
4 not identical) to the financial and operational characteristics of DTE Electric. The  
5 screening criterion requiring an investment grade credit rating ensures that the proxy  
6 companies, like DTE Electric, are in sound financial condition. Additionally, the  
7 criterion screening on the percent of net operating income from regulated electric  
8 operations distinguishes between electric utilities that are subject to regulation and  
9 those with substantial unregulated operations and are exposed to higher risks. In my



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1 opinion, these screens collectively reflect key risk factors that investors consider in  
2 making investments in electric utilities.

3

4 Cost of Equity Models

5 **Q28. What analytical approaches do you use to determine the Company's ROE?**

6 A28. As noted earlier, I rely on the constant growth and quarterly growth forms of the  
7 DCF model, the traditional and empirical forms of the CAPM, and the Bond Yield  
8 Plus Risk Premium approach. The models that I apply are commonly used in  
9 practice,<sup>17</sup> as well as in regulatory proceedings. Additionally, each model provides  
10 a different insight into investors' views of risk and return. Therefore, the use of  
11 multiple methods provides a comprehensive and robust perspective on investors'  
12 return requirements.

13

14 **Constant Growth Discounted Cash Flow Model**

15 **Q29. Please describe the Constant Growth DCF approach.**

16 A29. The Constant Growth DCF approach is based on the theory that a stock's current  
17 price represents the present value of all expected future cash flows. In its simplified  
18 form, the Constant Growth DCF model shown in Equation [1] below sets the ROE  
19 equal to the expected dividend yield plus the expected long-term annual growth rate  
20 in perpetuity:

21 
$$k = \frac{D_0 (1+g)}{P} + g \quad [1]$$

22 where:

23  $k$  = the required ROE,

---

17 See for example., Eugene Brigham, Louis Gapenski, Financial Management: Theory and Practice, 7th Ed., 1994, at 341.

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1  $D_0$  = the current annualized dividend,  
2  $P$  = the current stock price, and  
3  $g$  = the expected long-term annual growth rate.  
4

5 **Q30. What assumptions underlie the Constant Growth DCF model?**

6 A30. The Constant Growth DCF model assumes: (1) a constant average annual growth  
7 rate for earnings and dividends; (2) dividends are paid annually, and the dividend  
8 payout ratio is stable; (3) a constant Price/Earnings multiple; and (4) a discount rate  
9 greater than the expected growth rate. The model also assumes that the current cost  
10 of equity will remain constant in perpetuity.  
11

12 **Q31. What market data do you use to calculate the dividend yield in your Constant**  
13 **Growth DCF model?**

14 A31. I calculate the Constant Growth DCF result for each of the proxy companies using  
15 the following inputs:

- 16 • The average daily closing prices for the 30-, 90-, and 180-trading days ended  
17 January 31, 2025, for the term  $P$ ;
- 18 • The current quarterly dividend as of January 31, 2025 multiplied by 4, for  
19 the term  $D_0$ ; and
- 20 • Long-term earnings per share (“EPS”) growth rate projections as of January  
21 31, 2025, reported by Zacks, S&P Capital IQ,<sup>18</sup> and *Value Line* for the long-  
22 term growth rate,  $g$ .  
23

---

18 In prior testimonies, I have relied on analysts’ consensus long-term EPS projections from First Call as reported by Yahoo! Finance. As of November 2024, Yahoo! Finance no longer publishes consensus long-term projected EPS growth rates. Therefore, I now rely on analysts’ consensus EPS growth rate projections reported by S&P Capital IQ as a third source.

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1 **Q32. Why do you use three averaging periods to calculate an average stock price?**

2 A32. I do so to ensure that the model's results are not skewed by anomalous events that  
3 may affect stock prices on any given trading day. At the same time, the average  
4 period should reasonably reflect the expected capital market conditions over the  
5 long term. Using 30-, 90-, and 180-trading day averaging periods reasonably  
6 balances those concerns.

7  
8 **Q33. How do you calculate the expected dividend yield over the coming year?**

9 A33. Because utility companies tend to increase their quarterly dividends at different  
10 times throughout the year, it is reasonable to assume dividend increases will be  
11 evenly distributed over calendar quarters. Therefore, I calculate the expected  
12 dividend yield by applying one-half of the long-term growth rate to the current  
13 dividend yield. That adjustment ensures that the expected dividend yield is, on  
14 average, representative of the coming 12-month period.

15

16 **Q34. Why is the projected EPS growth the appropriate measure of long-term**  
17 **growth in the Constant Growth DCF model?**

18 A34. In its Constant Growth form, the DCF model (*i.e.*, as presented in Equation [1]  
19 above) assumes a single expected growth estimate in perpetuity, which assumes a  
20 fixed payout ratio, and the same constant growth rate in EPS, dividends per share,  
21 and book value per share. In the long run, dividend growth can only be sustained  
22 by earnings growth.

23

24 Further, academic studies have clearly and consistently shown that measures of  
25 earnings and cash flow are strongly related to returns, and that analysts' forecasts of

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1 growth are superior to other measures of growth in predicting stock prices.<sup>19</sup> For  
2 example, the research of Vander Weide and Carleton demonstrates that earnings  
3 growth projections have a statistically significant relationship to stock valuation  
4 levels, while dividend growth rates do not.<sup>20</sup> Those findings suggest that investors  
5 form their investment decisions based on expectations of growth in earnings, not  
6 dividends. Lastly, the only forward-looking growth rates that are available on a  
7 consensus basis are analysts' EPS growth rates. The fact that earnings growth  
8 projections are the only widely available estimates of growth further supports the  
9 conclusion that earnings growth is the most meaningful measure of growth among  
10 the investment community. For these reasons, earnings growth is the appropriate  
11 measure of long-term growth in the DCF model.

12

13 **Q35. What are the results of your Constant Growth DCF analysis?**

14 A35. To provide a spectrum of DCF-based ROE estimates, I calculate the low, mean,  
15 and high Constant Growth DCF result for each proxy company using the low, mean,  
16 and high EPS growth estimate. The mean result combines the average of the three  
17 EPS growth rate estimates with each proxy company's expected dividend yield.  
18 The high DCF result adds the maximum EPS growth rate estimate with each proxy  
19 company's expected dividend yield. Similarly, the low DCF result adds the  
20 minimum EPS growth rate estimate for each proxy company to the expected

---

19 See, e.g., Andreas C. Christofi, Petros C. Christofi, Marcus Lori and Donald M. Moliver, *Evaluating Common Stocks Using Value Line's Projected Cash Flows and Implied Growth Rate*, Journal of Investing (Spring 1999); Harris and Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management at 21 (Summer 1992); and Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management (Spring 1988); Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return*, Financial Management (Spring 1986).

20 See Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management (Spring 1988).

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dividend yield. I then calculate the mean and median low, mean, and high DCF results for the proxy group. In developing my ROE recommendation, I rely on the average of the mean and median proxy group Constant Growth DCF results (*see* Table 4, below, and Exhibit A-14 Schedule D5.1). By relying on the average of the mean and median proxy group results, I consider the individual DCF results of each proxy company while mitigating the effect of the highest and lowest estimates.

**Table 4      Constant Growth DCF Results<sup>21</sup>**

|                 | <b>Low</b> | <b>Mean</b> | <b>High</b> |
|-----------------|------------|-------------|-------------|
| 30-Day Average  | 9.54%      | 10.32%      | 11.01%      |
| 90-Day Average  | 9.42%      | 10.27%      | 10.91%      |
| 180-Day Average | 9.59%      | 10.40%      | 11.06%      |

**Quarterly Growth Discounted Cash Flow Model**

**Q36. Please describe the Quarterly Growth DCF model.**

A36. As noted earlier, the Constant Growth DCF model is based on several limiting assumptions, one of which is that dividends are paid annually. However, most dividend-paying companies, including utilities, pay dividends on a quarterly basis. Although the dividend yield adjustment discussed earlier is intended to reflect that assumption by increasing the observed dividend yield by one-half of the expected growth rate, it does not fully account for the quarterly receipt and reinvestment of dividends. Consequently, the Constant Growth DCF model likely understates the cost of equity. The Quarterly Growth DCF model specifically incorporates the quarterly payment of dividends, and the associated quarterly compounding of those dividends as they are reinvested at the required ROE. As noted by Dr. Roger Morin:

---

<sup>21</sup> See, Exhibit A-14 Schedule D5.1. Average of the proxy group mean and median results.

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1 *Clearly, given that dividends are paid quarterly and that the observed*  
2 *stock price reflects the quarterly nature of dividend payments, the*  
3 *market-required return must recognize quarterly compounding, for the*  
4 *investor receives dividend checks and reinvests the proceeds on a*  
5 *quarterly schedule... The annual DCF model inherently understates the*  
6 *investors' true return because it assumes all cash flows received by*  
7 *investors are paid annually.*<sup>22</sup>

8

9 **Q37. How is the dividend yield component calculated in the of the Quarterly DCF**  
10 **model?**

11 A37. To reflect the timing and compounding of quarterly dividends, the model replaces  
12 the "D" component of the Constant Growth DCF model with the following  
13 equation:

14 
$$D = d_1 (1 + k)^{0.75} + d_2 (1 + k)^{0.50} + d_3 (1 + k)^{0.25} + d_4 (1 + k)^0 \quad [2]$$

15 where:

16  $d_1, d_2, d_3, d_4$  = expected quarterly dividends over the coming year; and

17  $k$  = the required Return on Equity.<sup>23</sup>

18

19 To calculate the expected dividends over the coming year for the proxy companies  
20 (*i.e.*,  $d_1, d_2, d_3$ , and  $d_4$ ), I obtained the last four paid quarterly dividends for each  
21 company and multiplied them by one plus the growth rate (*i.e.*,  $1 + g$ ). To provide  
22 a spectrum of quarterly growth DCF-based ROE estimates, I calculate the low,  
23 mean, and high quarterly growth DCF result for each proxy company using the low,  
24 mean, and high EPS growth estimates. For the  $P$  component of the dividend yield, I  
25 used the same average stock prices applied in the Constant Growth DCF analysis  
26 for each proxy company.

---

22 Roger A. Morin, New Regulatory Finance, at 344 (2006).

23 Because the required ROE ( $k$ ) is a variable in the dividend yield calculation, the Quarterly Growth DCF model is solved iteratively.

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1 **Q38. What are the results of your Quarterly Growth DCF analyses?**

2 A38. My Quarterly Growth DCF results are summarized in Table 5 below (*see also*,  
3 Exhibit A-14 Schedule D5.2). As with my Constant Growth DCF analysis, I rely  
4 on the average of the mean and median proxy group results.

5 **Table 5 Quarterly Growth DCF Results<sup>24</sup>**

|                 | Low   | Mean   | High   |
|-----------------|-------|--------|--------|
| 30-Day Average  | 9.76% | 10.56% | 11.29% |
| 90-Day Average  | 9.63% | 10.52% | 11.20% |
| 180-Day Average | 9.81% | 10.68% | 11.34% |

6

7 **Capital Asset Pricing Model and Empirical Capital Asset Pricing Model**

8 **Q39. Please describe the general form of the CAPM.**

9 A39. The CAPM is a risk premium method that estimates the cost of equity for a given  
10 security as a function of a risk-free return plus a risk premium to compensate  
11 investors for the non-diversifiable or “systematic” risk of that security. As shown  
12 in Equation [3], the CAPM is defined by four components, each of which  
13 theoretically is a forward-looking estimate:

14 
$$K_e = r_f + \beta(r_m - r_f) \quad [3]$$

15 where:

16  $K_e$  = the required market ROE for a security;

17  $\beta$  = the Beta coefficient of that security;

18  $r_f$  = the risk-free rate of return; and

19  $r_m$  = the required return on the market as a whole.

20

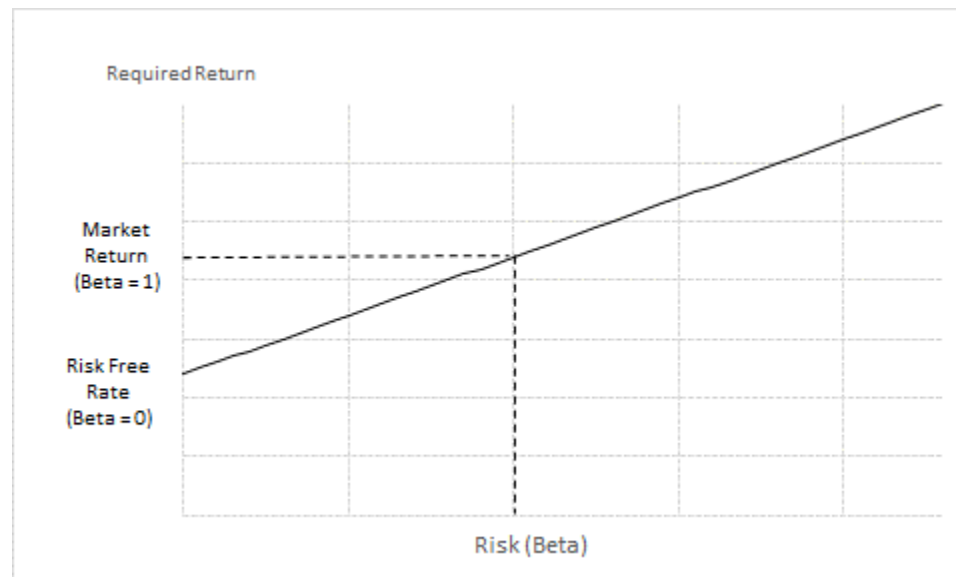
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24 <sup>24</sup> See, Exhibit A-14 Schedule D5.2. Average of the proxy group mean and median results.

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Equation [3] describes the Security Market Line (“SML”), or the CAPM risk-return relationship, depicted in Figure 3 below. The intercept is the risk-free rate ( $r_f$ ) which has a Beta coefficient of zero, and the slope is the expected market risk premium ( $r_m - r_f$ ). As shown in Figure 3, the SML is upward sloping, illustrating the principle that investments of higher risk require a higher return. By definition,  $r_m$ , the return on the market, has a Beta coefficient of 1.00. A Beta coefficient of less than 1.00 generally indicates less market risk and a lower required return than the market; conversely, a company with a Beta coefficient greater than 1.00 has higher market risk, thereby warranting a higher required return than the market by investors.

**Figure 3. Security Market Line**



The CAPM assumes that all non-market or unsystematic risk, can be eliminated through diversification. The risk that cannot be eliminated through diversification is called market, or systematic risk. Systemic (or non-diversifiable) risk is measured by the Beta coefficient, which is defined as:



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1

$$\beta_j = \frac{\sigma_j}{\sigma_m} \times \rho_{j,m} \quad [4]$$

2

where  $\sigma_j$  is the standard deviation of returns for company “j,”  $\sigma_m$  is the standard deviation of returns for the broad market (as measured, for example, by the S&P 500 Index), and  $\rho_{j,m}$  is the correlation of returns between company  $j$  and the broad market. The Beta coefficient, therefore, represents both relative volatility (*i.e.*, the standard deviation) of returns, and the correlation in returns between the subject company and the overall market.

8

9 **Q40. What risk-free rate assumptions do you include in your CAPM analysis?**

10 A40. I apply two different estimates of the risk-free rate: (1) the 30-day average yield on  
11 30-year Treasury bonds as of January 31, 2025 (*i.e.*, 4.82 percent);<sup>25</sup> and (2) a  
12 projected 30-year Treasury yield (*i.e.*, 4.46 percent).<sup>26</sup>

13

14 **Q41. Why do you rely on the 30-year Treasury yield in the CAPM analysis?**

15 A41. In determining the security most relevant to the application of the CAPM, the term  
16 (or maturity) should approximate the life of the underlying investment. Electric  
17 utilities are typically long-term duration investments; therefore, the 30-year  
18 Treasury yield is most suitable for the risk-free rate applied in the CAPM.

19

20 **Q42. What Beta coefficients do you use in your CAPM model?**

21 A42. I rely on the average Beta coefficients from *Value Line* and Bloomberg for each  
22 proxy company as of January 31, 2025. Beta coefficients from both services are

---

25 Source: Bloomberg Professional Services.

26 The average of: (1) the average projected 30-year Treasury yield for the six quarters ended Q2 2026; and (2) the average long-term projected 30-year Treasury yield for the years 2026-2030 and 2031-2035 reported by Blue Chip Financial Forecast. See, Blue Chip Financial Forecast, Vol. 44, No. 2, January 30, 2025, at 2 and Blue Chip Financial Forecast, Vol. 43, No. 12, November 27, 2024, at 14.

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1 calculated using weekly returns over a five-year period, adjusted to reflect the  
2 tendency of Beta coefficients to regress toward the market mean of 1.00.

3

4 **Q43. What estimates of the expected market return do you use to calculate the**  
5 **market risk premium?**

6 A43. I consider two estimates of the expected market return. The first estimate is a  
7 forward-looking estimate that calculates the market capitalization-weighted ROE  
8 of the S&P 500 Index by applying the Constant Growth DCF model to the S&P  
9 500 Index. The second estimate is the long-run historical arithmetic average market  
10 return of 12.17 percent reported by Kroll (formerly Duff & Phelps) for the years  
11 1926 to 2024.<sup>27</sup>

12

13 **Q44. Please further explain your forward-looking approach to estimating the**  
14 **market return.**

15 A44. Using the Constant Growth DCF model described earlier, I develop two estimates  
16 of the expected market return by applying dividend yields from Bloomberg and  
17 projected earnings growth rates from Bloomberg and *Value Line*. I calculate a  
18 market capitalization-weighted dividend yield and projected earnings growth rate  
19 for the S&P 500 Index and applied those estimates to the Constant Growth DCF  
20 formula, using the same half-growth rate assumption described earlier. The  
21 expected market return from Bloomberg and *Value Line* are 16.34 percent and  
22 15.29 percent, respectively (*see* Exhibit A-14 Schedule D5.3). To be conservative,  
23 I rely on *Value Line's* expected market return estimate of 15.29 percent in my  
24 CAPM analyses.

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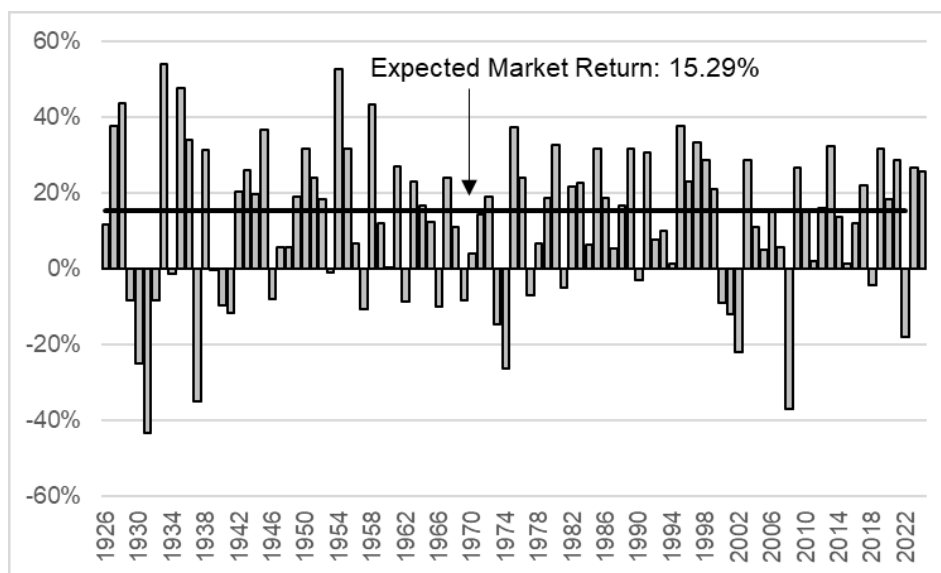
27 Source: Kroll, Cost of Capital Navigator.

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1 **Q45. Is the Value-Line DCF-based estimate of 15.29 percent consistent with actual**  
2 **observed returns on the market?**

3 A45. Yes, it is. As shown in Figure 4 below, an expected market return of 15.29 percent  
4 or higher occurred in 49 of the last 99 years (i.e., 50 percent of the time). Since  
5 2009, the annual market return has averaged 15.58 percent, and equaled or  
6 exceeded 15.29 percent in nine of the last 16 years and 11 of the last 23 years. In  
7 other words, an annual market return of 15.29 percent, or higher, has occurred  
8 frequently.

9 **Figure 4. Annual Market Return (1926-2024)<sup>28</sup>**



10

11 **Q46. Why do you also consider the long-term arithmetic average historical return**  
12 **on the market of 12.17 percent as an alternate estimate of the expected market**  
13 **return?**

14 A46. My objective is to develop a reasonable estimate of the expected market return over  
15 the long term to calculate an expected market risk premium. Because the cost of

28 Source: Kroll, 2023 SBBI Yearbook, Appendix A-1, A-7 (years 1926-2022); Cost of Capital Navigator (2023, 2024 data).

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equity is forward looking, any estimate – whether based on historical or projected data – assumes the estimate reflects investors’ expectations into the future. From that perspective, applying the long-run historical arithmetic average market return as an alternate estimate of the expected market return is prospective in nature. The 15.29 percent forward market return is consistent with historically observed market returns (as shown in Figure 4 above) yet is above the long-term arithmetic average market return. Therefore, it may be reasonable to expect that, over the long term, the market return will revert to its long-run historical arithmetic average.

**Q47. With the risk-free rates and required market return estimates described above, how do you calculate the market risk premium?**

A47. I apply two estimates of the risk-free rate and two estimates of the expected market return. Combined, those variables produce four estimates of the market risk premium, ranging from 7.35 percent to 10.83 percent as shown below in Table 6.

**Table 6      Market Risk Premium Estimates**

|                                                                | <b>Current Risk-Free<br/>Rate (4.82%)</b> | <b>Projected Risk-Free<br/>Rate (4.46%)</b> |
|----------------------------------------------------------------|-------------------------------------------|---------------------------------------------|
| <i>Value Line</i> DCF-based Expected<br>Market Return (15.29%) | 10.47%                                    | 10.83%                                      |
| Long-Term Historical Average<br>Market Return (12.17%)         | 7.35%                                     | 7.71%                                       |

**Q48. What are the results of your CAPM analysis?**

A48. As shown in Exhibit A-14 Schedule D5.4, the CAPM results range from 11.51 percent to 14.39 percent (*see* Table 7 below).

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1

**Table 7 Summary of CAPM Results<sup>29</sup>**

|                                            | <b>Current Risk-Free Rate<br/>(4.82%)</b> | <b>Projected Risk-Free Rate<br/>(4.46%)</b> |
|--------------------------------------------|-------------------------------------------|---------------------------------------------|
| Long-Term Historical Average Market Return | 11.54%                                    | 11.51%                                      |
| DCF-Based Expected Market Return           | 14.39%                                    | 14.36%                                      |

2

3 **Q49. Do you consider another form of the CAPM?**

4 A49. Yes, I also consider the Empirical CAPM (“ECAPM”) approach, which calculates  
5 the product of the adjusted Beta coefficient and the Market Risk Premium and  
6 applies a weight of 75.00 percent to that result. The model then applies a 25.00  
7 percent weight to the Market Risk Premium, without any effect from the Beta  
8 coefficient.<sup>30</sup> The results of the two calculations are summed, along with the risk-  
9 free rate, to produce the ECAPM result, as expressed in Equation [5] below:

$$10 \quad k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \quad [5]$$

11 where:

12  $k_e$  = the required market ROE;

13  $\beta$  = Adjusted Beta coefficient of an individual security;

14  $r_f$  = the risk-free rate of return; and

15  $r_m$  = the required return on the market as a whole.

16

17 **Q50. What is the benefit of the ECAPM approach?**

18 A50. The ECAPM corrects the tendency of the CAPM to underestimate the cost of equity  
19 for companies, such as regulated utilities, with low Beta coefficients, and to  
20 overstate the cost of equity for companies with high Beta coefficients. As discussed

29 See, Exhibit A-14 Schedule D5.4.

30 See, e.g., Roger A. Morin, New Regulatory Finance, at 189-190 (2006).

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1 below, the ECAPM recognizes academic research that indicates that the risk-return  
2 relationship is flatter than the relationship estimated by the CAPM, and that the  
3 CAPM under-estimates the alpha, or the constant return term.<sup>31</sup>

4

5 Numerous tests of the CAPM have measured the extent to which security returns  
6 and Beta coefficients are related as predicted by the CAPM. The ECAPM method  
7 reflects the finding that the actual SML is not as steeply sloped as the SML predicted  
8 by the CAPM formula.<sup>32</sup> Fama and French found that the actual returns on the low  
9 Beta coefficient portfolios were higher than the CAPM-predicted returns, and vice  
10 versa for the high Beta coefficient portfolios.<sup>33</sup> Similarly, Dr. Morin states:

11 *With few exceptions, the empirical studies agree that . . . low-beta*  
12 *securities earn returns somewhat higher than the CAPM would predict,*  
13 *and high-beta securities earn less than predicted.*

14

\*\*\*

15 *Therefore, the empirical evidence suggests that the expected return on a*  
16 *security is related to its risk by the following approximation:*

17 
$$K = R_F + x (R_M - R_F) + (1-x)\beta(R_M - R_F)$$

18 *where x is a fraction to be determined empirically. The value of x that*  
19 *best explains the observed relationship  $\text{Return} = 0.0829 + 0.0520 \beta$  is*  
20 *between 0.25 and 0.30. If  $x = 0.25$ , the equation becomes:*

21 
$$K = R_F + 0.25(R_M - R_F) + 0.75 \beta(R_M - R_F)^{34}$$

---

31 *Id.*, at 191 (“The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company’s beta is estimated accurately, the CAPM still understates the return for low-beta stocks.”).

32 *Id.*, at 175.

33 Eugene F. Fama & Kenneth R. French, *The Capital Asset Pricing Model: Theory and Evidence*, Journal of Economic Perspectives, Vol. 18, No. 3, Summer 2004, at 33.

34 Roger A. Morin, New Regulatory Finance, at 175, 190 (2006).

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1 **Q51. Does the application of adjusted Beta coefficients in the ECAPM address the**  
2 **empirical issues with the CAPM?**

3 A51. No, it does not. Beta coefficients are adjusted because of their general regression  
4 tendency to converge toward 1.00 over time, *i.e.*, over successive calculations. As  
5 also noted earlier, numerous studies have determined that at any given point in time,  
6 the actual SML is not as steeply sloped as the SML predicted by the CAPM  
7 formula. To that point, Dr. Morin explains:

8 *Some have argued that the use of the ECAPM is inconsistent with the use*  
9 *of adjusted betas, such as those supplied by Value Line and Bloomberg.*  
10 *This is because the reason for using the ECAPM is to allow for the*  
11 *tendency of betas to regress toward the mean value of 1.00 over time,*  
12 *and, since Value Line betas are already adjusted for such trend, an*  
13 *ECAPM analysis results in double-counting. This argument is*  
14 *erroneous. Fundamentally, the ECAPM is not an adjustment, increase*  
15 *or decrease, in beta. This is obvious from the fact that the expected*  
16 *return on high beta securities is actually lower than that produced by the*  
17 *CAPM estimate. The ECAPM is a formal recognition that the observed*  
18 *risk-return tradeoff is flatter than predicted by the CAPM based on*  
19 *myriad empirical evidence. The ECAPM and the use of adjusted betas*  
20 *comprised two separate features of asset pricing. Even if a company's*  
21 *beta is estimated accurately, the CAPM still understates the return for*  
22 *low-beta stocks. Even if the ECAPM is used, the return for low-beta*  
23 *securities is understated if the betas are understated. Referring back to*  
24 *Figure 6-1, the ECAPM is a return (vertical axis) adjustment and not a*  
25 *beta (horizontal axis) adjustment. Both adjustments are necessary.<sup>35</sup>*

26 Therefore, it is appropriate to rely on adjusted Beta coefficients in both the CAPM  
27 and ECAPM.

28

29 **Q52. Are you aware of academic studies that support the use of the ECAPM for**  
30 **utilities?**

31 A52. Yes, I am. In a 2011 study by Stéphane Chrétien and Frank Coggins, the authors  
32 studied the CAPM's ability to estimate the risk premium for the utility industry in

---

35 *Ibid.*, at 191.

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particular subgroups of utilities.<sup>36</sup> The study considered the traditional CAPM approach, the Fama-French three-factor model, and a model similar to the ECAPM. In the study, the ECAPM relied on adjusted Beta coefficients similar to *Value Line's* approach. As Chrétien and Coggins found, the ECAPM significantly outperformed the traditional CAPM model at predicting the observed risk premium for the various utility subgroups.

**Q53. What are the results of your ECAPM analyses?**

A53. I apply the same market return, Beta coefficients, and risk-free rates described earlier to the ECAPM formula shown in Equation [5] above. The results of my ECAPM analyses are shown on Exhibit A-14 Schedule D5.4 and summarized in Table 8 below.

**Table 8 Summary of ECAPM Results<sup>37</sup>**

|                                            | <b>Current Risk-Free Rate<br/>(4.82%)</b> | <b>Projected Risk-Free Rate<br/>(4.46%)</b> |
|--------------------------------------------|-------------------------------------------|---------------------------------------------|
| Long-Term Historical Average Market Return | 11.70%                                    | 11.68%                                      |
| DCF-Based Expected Market Return           | 14.61%                                    | 14.59%                                      |

**Bond Yield Plus Risk Premium Approach**

**Q54. Please describe the Bond Yield Plus Risk Premium approach.**

A54. The Bond Yield Plus Risk Premium approach is based on the basic financial principle of risk and return, which states that equity investors require a premium

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<sup>36</sup> Stéphane Chrétien and Frank Coggins, *Cost of Equity for Energy Utilities: Beyond The CAPM*, *Energy Studies Review*, Vol. 18, No. 2 (2011).

<sup>37</sup> See, Exhibit A-14 Schedule D5.4.



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1 over the return required as a bondholder to compensate for the residual risk  
2 associated with equity ownership. Risk Premium approaches, therefore, estimate  
3 the cost of equity as the sum of the equity risk premium and the yield on a particular  
4 class of bonds.

5

6 **Q55. Please explain how you perform your Bond Yield Plus Risk Premium analysis.**

7 A55. I first define the equity risk premium as the difference between the authorized ROE  
8 and the then-prevailing level of long-term (*i.e.*, 30-year) Treasury yield, using the  
9 authorized ROE for 1,822 electric utility rate proceedings between January 1, 1980  
10 and January 31, 2025. To reflect the prevailing level of bond yields during the  
11 pendency of the proceedings, I calculate the average 30-year Treasury yield over  
12 the average period between the filing of the rate case and the date of the final order  
13 (approximately 201 trading days).

14

15 Because the data spans several economic cycles over more than four decades, the  
16 analysis incorporates changes in the equity risk premium over time. Prior research,  
17 has shown that the equity risk premium is inversely related to the level of bond  
18 yields.<sup>38</sup>

---

38 In other words, declines in the 30-year Treasury yield are related to an increase in the Equity Risk Premium and vice versa. *See, for example*, Robert S. Harris and Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, (Summer 1992), at 63-70; Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management, (Spring 1985), at 33-45; and Farris M. Maddox, Donna T. Pippert, and Rodney N. Sullivan, *An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry*, Financial Management, (Autumn 1995), at 89-95.

1    **Q56. How do you analyze the relationship between bond yields and the equity risk**  
2    **premium?**

A56. I estimate the relationship between bond yields and the equity risk premium by applying a regression analysis, in which the observed equity risk premium described above is the dependent variable, and the 30-year Treasury yield is the independent variable. To account for the variability in bond yields and authorized ROEs over several decades, I used the semi-log regression, in which the equity risk premium is expressed as a function of the natural log of the 30-year Treasury yield:

$$9 \qquad RP = b + m (\text{LN}(T_{30})) \quad [6]$$

11  $RP$  = the equity risk premium

12  $T_{30}$  = the lagged 30-year Treasury bond yield

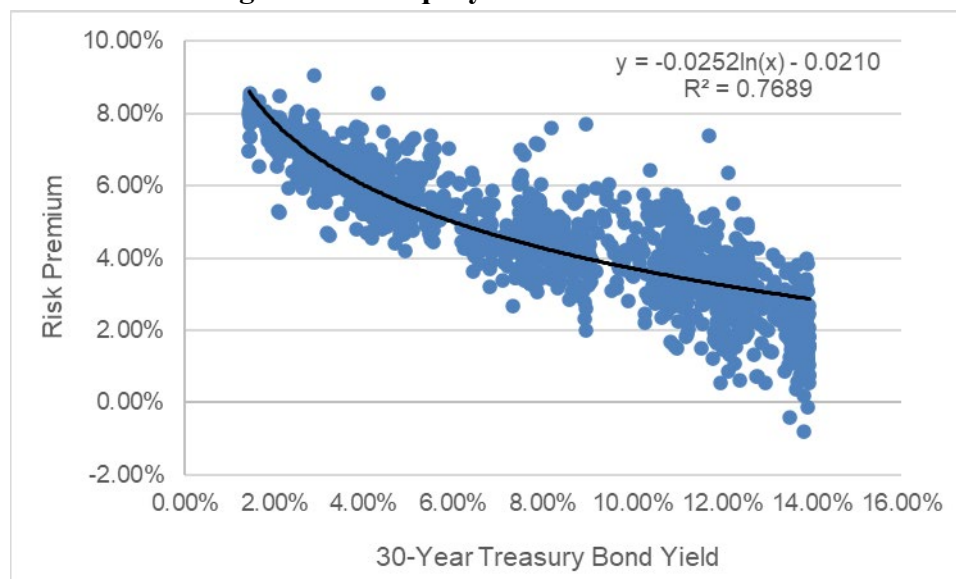
13  $b =$  the constant term of the regression

14  $m$  = the slope coefficient of the regression

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**Figure 5. Equity Risk Premium<sup>39</sup>**



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As Figure 5 illustrates, the equity risk premium increases as interest rates fall. The finding that the equity risk premium and interest rates are inversely related is supported by published research. For example, Dr. Roger Morin cites several studies and concludes that, “beginning in 1980, risk premiums varied inversely with the level of interest rates – rising when rates fell and declining when interest rates rose.”<sup>40</sup> Applying the regression coefficients in Figure 5 produces ROE estimates of 10.20 percent to 10.37 percent (*see* also Exhibit A-14 Schedule D5.5).

11

**Table 9 Summary of Bond Yield Plus Risk Premium Results<sup>41</sup>**

|                            | <b>30-Year Treasury Bond</b> | <b>Risk Premium</b> | <b>Return on Equity</b> |
|----------------------------|------------------------------|---------------------|-------------------------|
| Current 30-Year Treasury   | 4.82%                        | 5.54%               | 10.37%                  |
| Projected 30-Year Treasury | 4.46%                        | 5.74%               | 10.20%                  |

39 See, Exhibit A-14 Schedule D5.5.

40 Roger A: Morin, Ph.D., New Regulatory Finance, Public Utilities Reports, Inc., at 128 (2006).

41 See, Exhibit A-14 Schedule D5.5.

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1   **Q57. What are the advantages of the Bond Yield Plus Risk Premium approach?**

2   A57. There are several advantages. First, authorized ROEs in other jurisdictions are a  
3       significant part of the market information that investors consider when evaluating  
4       their investment alternatives. Therefore, they are a direct measure of returns  
5       available to other electric utilities, as required under the comparable return standard  
6       of the *Hope* and *Bluefield* decisions. The level of authorized ROE also provides a  
7       signal to investors about the level of regulatory support that a company can expect  
8       with regard to its ability to compete for capital and ensure its financial integrity.  
9       An ROE below its peers for a given period may be an impediment to the Company's  
10      ability to attract capital and finance the infrastructure required to provide safe,  
11      reliable service to its customers.

12      Second, the use of the Bond Yield Plus Risk Premium model in conjunction with  
13      the DCF and CAPM approaches adds diversity to the model results, which enables  
14      a more robust and reliable ROE estimate. The fewer models that are relied upon,  
15      the more likely it is that model risk biases the ultimate ROE determination. For the  
16      same reasons that diversity is a wise and prudent investment strategy, diversity of  
17      the models used to estimate the ROE is similarly prudent, as it reduces the risk that  
18      the results of any single model may not reasonably reflect investors' return  
19      requirements.

20  
21      A third advantage of the Bond Yield Plus Risk Premium approach is its simplicity  
22      and reliance on fewer contentious inputs. Lastly, the Bond Yield Plus Risk Premium  
23      approach adds a measure of stability because it is less vulnerable to changes in  
24      market data. As shown in the regression equation in Figure 5, the change in the risk

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1 premium (and therefore the ROE estimate) as a result of a change in bond yields is  
2 less than one-to-one. For example, as shown in Table 9 above, a 36-basis point  
3 increase in the bond yield (from 4.46 percent to 4.82 percent) results in only a 17-  
4 basis point change in the ROE from 10.20 percent to 10.37 percent.

5

6 **IV. Business Risks and Other Considerations**

7 **Q58. Are there factors specific to DTE's operating environment that you considered**  
8 **in your ROE recommendation?**

9 A58. Yes, there are several additional factors that have a direct bearing on DTE Electric's  
10 ability to earn a fair return and on the Company's riskiness relative to the proxy  
11 group, including (1) its substantial capital expenditure program, (2) Michigan's  
12 ambitious clean energy mandates that the Company must meet, and (3) the  
13 regulatory environment in which it operates. Those factors, which are discussed  
14 below, should be considered in terms of their overall effect on the Company's  
15 business risk and, therefore, its cost of equity.

16

17 Capital Expenditure Program

18 **Q59. Do you have any preliminary thoughts on the importance of access to capital**  
19 **for electric utilities such as DTE Electric?**

20 A59. Yes, I do. As a capital-intensive enterprise, the allowed ROE should enable DTE  
21 Electric to finance capital expenditures and working capital requirements at  
22 reasonable rates and to maintain its financial integrity in a variety of economic and  
23 capital market conditions. As discussed throughout my Direct Testimony, a return  
24 that is adequate to attract capital at reasonable terms enables the utility to provide  
25 customers with safe, reliable service while maintaining its financial soundness.

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1 This is especially important during periods in which a large capital expenditure  
2 program is planned.

3

4 Electric utilities are one of the most capital-intensive sectors. On average, electric  
5 utilities generate less than one-third as much revenue per dollar of assets as the non-  
6 utility U.S. companies covered by *Value Line*.<sup>42</sup> To fund the significant capital  
7 expenditures needed to maintain, expand, and modernize existing infrastructure,  
8 electric utilities require sufficient internally generated cash flow and ongoing access  
9 to investor supplied capital. Because electric utilities are often cash flow negative  
10 (*i.e.*, cash spent on plant is often more than cash flow received from operations), it  
11 is critical that regulation enable timely cost recovery and provide predictable,  
12 adequate, and achievable allowed returns that support the financial integrity of the  
13 utility.

14

15 As shown in Figure 6 below, the Company's ratio of cash outflows for plant to net  
16 cash flow from operations has been generally above 1.0<sup>43</sup> and greater than the proxy  
17 group median ratio in nine of the last ten years. Because cash spent on plant is  
18 greater than cash received from operations, the Company requires more external  
19 capital to finance its capital expenditures than the median proxy company does. As  
20 such, it is to customers' benefit that the Company can access external capital on  
21 cost effective and favorable terms.

---

42 Source: *Value Line* screener, accessed February 22, 2025.

43 In other words, cash spent on plant is greater than cash received from operations.



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1 significant investment in its distribution system. Company witness Chiu describes  
2 DTE Electric's capital investment needs in more detail.

3

4 **Q61. How do DTE Electric's capital expenditure requirements affect its risk**  
5 **profile?**

6 A61. As with any utility facing substantial capital expenditure requirements, the  
7 Company's risk profile is affected in two significant and related ways: (1) the  
8 heightened level of investment increases the risk of under recovery or delayed  
9 recovery of the invested capital; and (2) an inadequate return would put downward  
10 pressure on key credit metrics. Both would increase the Company's risk profile,  
11 making it a less attractive investment compared to other utilities that have more  
12 timely cost recovery.

13 **Q62. Do credit rating agencies recognize the risks associated with elevated levels of**  
14 **capital expenditures?**

15 A62. Yes. From a credit perspective, the additional pressure on cash flows associated  
16 with higher levels of capital expenditures exerts corresponding pressure on credit  
17 metrics and, therefore, credit ratings. To that point, S&P explains the importance  
18 of regulatory support for large capital projects:

19 *When applicable, a jurisdiction's willingness to support large capital*  
20 *projects with cash during construction is an important aspect of our*  
21 *analysis. This is especially true when the project represents a major*  
22 *addition to rate base and entails long lead times and technological risks*  
23 *that make it susceptible to construction delays. Broad support for all*  
24 *capital spending is the most credit-sustaining. Support for only specific*  
25 *types of capital spending, such as specific environmental projects or*  
26 *system integrity plans, is less so, but still favorable for creditors.*  
27 *Allowance of a cash return on construction work-in-progress or similar*  
28 *ratemaking methods historically were extraordinary measures for use in*  
29 *unusual circumstances, but when construction costs are rising, cash flow*



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1 *support could be crucial to maintain credit quality through the spending*  
2 *program. Even more favorable are those jurisdictions that present an*  
3 *opportunity for a higher return on capital projects as an incentive to*  
4 *investors.<sup>47</sup>*

5 Moody's also notes that growing power demand, the need to improve grid resilience,  
6 and advancing efforts to reduce carbon emissions is increasing capital expenditure  
7 pressure for utilities, widening cash flow deficits and weakening their financial  
8 strength:

9 *Credit pressure is emerging most acutely for companies with large,*  
10 *complete or multiyear projects or for those that are experiencing a delay*  
11 *in the recovery of investment costs. Unlike exogenous events of recent*  
12 *years – such as severe storms, commodity price spikes and the COVID-*  
13 *19 pandemic, which we viewed as temporary events – capital spending*  
14 *and related financings are core long-term financial policy issues.<sup>48</sup>*

15 To the extent that the regulatory environment does not enable timely and sufficient  
16 cost recovery of its full cost of doing business, including capital costs, the Company  
17 will face increased pressure on its credit metrics resulting in higher costs of both  
18 debt and equity. Maintaining access to capital markets on favorable terms is  
19 especially important for utilities and their customers during periods of significant  
20 capital investment. Capital cost recovery mechanisms are viewed positively by  
21 investors; however, maintaining the ability to access capital markets on favorable  
22 terms, in the form of financial integrity (i.e., capital structure and return on equity)  
23 is especially important for utilities and their customers during periods of significant  
24 capital investment.

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47 S&P Global Ratings, "Assessing U.S. Investor-Owned Utility Regulatory Environments," August 10, 2016, at 7.

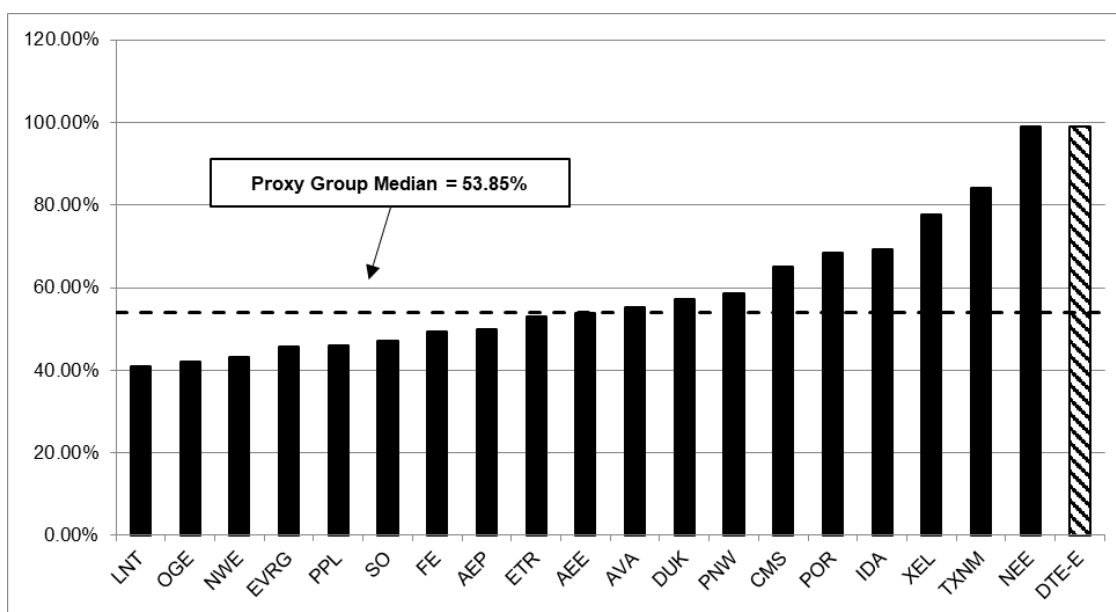
48 Moody's Ratings, "High capital spending will weigh on credit quality without supportive company actions," October 21, 2024.

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1 **Q63. Have you analyzed how DTE Electric's capital investment program compares**  
2 **to those of the proxy group companies?**

3 A63. Yes. I compared the ratio of projected capital expenditures to 2023 net utility plant  
4 for DTE Electric to the ratios for the proxy group companies. Figure 7 shows that  
5 the Company's ratio of projected capital expenditures to net utility plant is the  
6 highest of all the proxy companies and is 1.84 times higher than the median ratio  
7 for the proxy group of 53.85 percent (see Exhibit A-14 Schedule D5.6). The  
8 Company embraces this challenge and understands the capital expenditure program  
9 is required to achieve a carbon-free future and become a national leader in  
10 renewable energy development.

12 **Figure 7. Ratio of 2025-29 Capital Expenditures to 2023 Net Utility Plant<sup>49</sup>**



49 Exhibit A-14 Schedule D5.6.

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1   **Q64. What is your conclusion regarding the effect of DTE Electric’s projected**  
2       **capital expenditure program on its risk profile and cost of equity?**

3   A64. DTE Electric is undertaking a substantial capital spending program through 2029  
4       that will require the Company to maintain access to capital markets on reasonable  
5       terms and conditions. DTE Electric’s ratio of capital expenditure requirements to  
6       net utility plant is the highest of all the proxy companies, and the absolute  
7       magnitude of its capital program places pressure on the Company’s cash flows and  
8       credit metrics without timely cost recovery. Further, DTE Electric requires more  
9       external financial capital than its peers. For these reasons, it is important that the  
10      authorized ROE be set at a level that allows DTE Electric to continue to attract both  
11      debt and equity under favorable terms under a variety of economic and financial  
12      market conditions. Importantly, this will enable the Company to deliver on the  
13      clean energy goals of SB 271.

14

15   Environmental and Clean Energy Mandates

16   **Q65. Please describe the renewable and clean energy mandates that will be required**  
17       **by DTE Electric to achieve Michigan’s clean energy goals.**

18   A65. In 2023, the Michigan legislature passed a package of clean energy legislation that  
19       set an ambitious clean energy target for the state of Michigan. In particular, SB  
20       271 requires 80 percent carbon-free electricity sales by 2035 and 100 percent  
21       carbon free by 2040.<sup>50</sup> Further, the legislation requires achieving 50 percent  
22       renewable energy by 2030, increasing to 60 percent by 2035. As a point of context,  
23       achieving 60 percent renewable energy in 2035 would represent a quadrupling of

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50   <https://www.michigan.gov/egle/newsroom/mi-environment/2023/11/28/michigan-becomes-a-national-leader-in-climate-action-with-new-legislation>

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1 renewable energy resources from Michigan’s 16 percent level in 2023.<sup>51</sup> Meeting  
2 these mandates will require significant investments in renewable energy resources.  
3 As such, a compensatory return will be required to attract the capital that is needed  
4 to achieve such ambitious policy objectives.

5

6 **Q66. Have you considered how the clean energy requirements in SB 271 compare**  
7 **to other states and the proxy companies?**

8 A66. Yes, I have. According to a 2024 report by the Lawrence Berkeley National  
9 Laboratory, Michigan is one of 16 jurisdictions that have a 100 percent Clean  
10 Energy Standard (“CES”) by 2050; four jurisdictions<sup>52</sup> have a 100 percent  
11 Renewable Portfolio Standard (“RPS”) by 2050 (see Figure 8).<sup>53</sup>

---

51 <https://www.michigan.gov/egle/newsroom/mi-environment/2023/11/28/michigan-becomes-a-national-leader-in-climate-action-with-new-legislation>

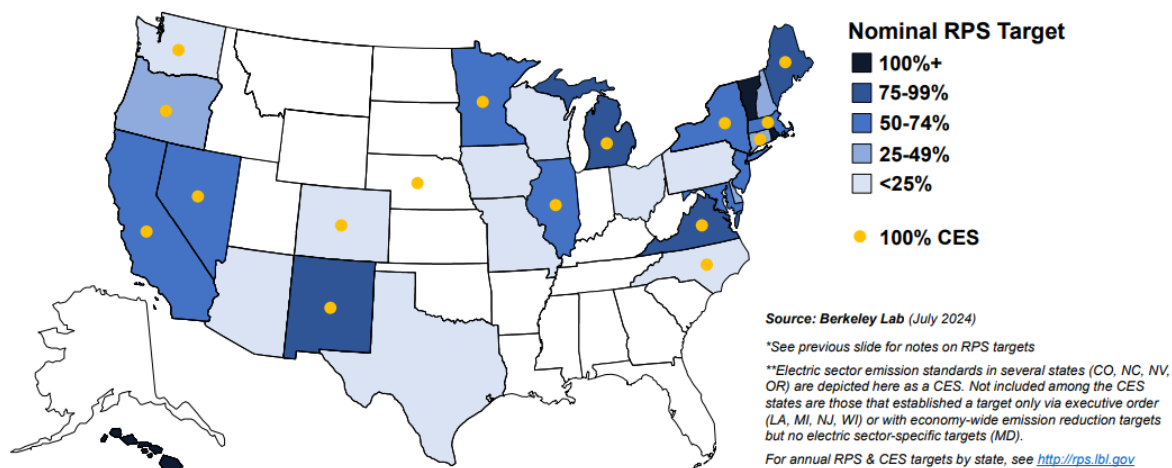
52 District of Columbia, Hawaii, Rhode Island, and Vermont.

53 Source: Lawrence Berkeley National Laboratory, U.S. State Renewables Portfolio & Clean Electricity Standards: 2024 Status Update, August 2024, [https://eta-publications.lbl.gov/sites/default/files/lbnl\\_rps\\_ces\\_status\\_report\\_2024\\_edition.pdf](https://eta-publications.lbl.gov/sites/default/files/lbnl_rps_ces_status_report_2024_edition.pdf). The report defines a RPS as “A binding requirement on retail electric suppliers to procure a minimum percentage of generation from eligible sources of renewable electricity” and a CES as “Similar to an RPS, but target is based on a broader set of eligible technologies; may not (yet) have a defined implementation/enforcement mechanism”.

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**Figure 8. RPS and Clean Energy Standards<sup>54</sup>**



2

3 To compare this information for each proxy company, I reviewed the jurisdictions  
4 in which each of the proxy companies operate and calculated the percentage of  
5 operating companies that operate in the 20 jurisdictions with a 100 percent CES  
6 or RPS. As shown in Figure 9 below, only two proxy companies operate entirely  
7 in jurisdictions with a 100 percent CES or 100 percent RPS like DTE Electric.

54 Source: Lawrence Berkeley National Laboratory, U.S. State Renewables Portfolio & Clean Electricity Standards: 2024 Status Update, August 2024, [https://eta-publications.lbl.gov/sites/default/files/lbnl\\_rps\\_ces\\_status\\_report\\_2024\\_edition.pdf](https://eta-publications.lbl.gov/sites/default/files/lbnl_rps_ces_status_report_2024_edition.pdf)

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**Figure 9. Proxy Group Operating Companies that**

2

**Operate in Jurisdictions with 100% CES or RPS<sup>55</sup>**

| <b>Company</b>                        | <b>Percentage of<br/>Operating<br/>Companies in<br/>Jurisdictions with<br/>100% CES or RPS</b> |
|---------------------------------------|------------------------------------------------------------------------------------------------|
| <i>DTE Electric Company</i>           | <i>100%</i>                                                                                    |
| CMS Energy Corporation                | 100%                                                                                           |
| Portland General Electric Company     | 100%                                                                                           |
| Ameren Corporation                    | 50%                                                                                            |
| IDACORP, Inc.                         | 50%                                                                                            |
| TXNM Energy, Inc.                     | 50%                                                                                            |
| Xcel Energy, Inc.                     | 50%                                                                                            |
| PPL Corporation                       | 40%                                                                                            |
| Avista Corporation                    | 33%                                                                                            |
| Duke Energy Corporation               | 25%                                                                                            |
| Entergy Corporation                   | 20%                                                                                            |
| American Electric Power Company, Inc. | 17%                                                                                            |
| Evergy, Inc.                          | 0%                                                                                             |
| FirstEnergy Corporation               | 0%                                                                                             |
| Alliant Energy Corporation            | 0%                                                                                             |
| NextEra Energy, Inc.                  | 0%                                                                                             |
| NorthWestern Energy Group, Inc.       | 0%                                                                                             |
| OGE Energy Corporation                | 0%                                                                                             |
| Pinnacle West Capital Corporation     | 0%                                                                                             |
| Southern Company                      | 0%                                                                                             |

3

4

As shown in Exhibit A-14 Schedule D5.7, only 23 percent of the operating

5

companies within the proxy group operate in a state that has a 100 percent clean

6

energy standard or 100 percent RPS by 2050. Therefore, the requirements imposed

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55 See, Exhibit A-14 Schedule D5.7.

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1 on DTE Electric are only matched by CMS Energy Corporation and Portland  
2 General Electric Company.

3

4 **Q67. What is your conclusion regarding the effect of Michigan's clean energy goals**  
5 **on the Company's cost of equity?**

6 A67. Michigan's ambitious clean energy mandates place significant requirements on the  
7 Company which will require it to make substantial investments in its system. To  
8 access capital required to finance these mandated investments, the Company must  
9 maintain a strong financial profile, and offer investors a compensatory return and  
10 timely recovery of and on its investment. These requirements are more ambitious  
11 than the states in which its peers operate, placing greater risk on the Company.

12

13 Regulatory Environment

14 **Q68. How does the regulatory environment in which a utility operates affect its cost**  
15 **of capital?**

16 A68. The regulatory environment is one of the most important factors investors consider  
17 when assessing a utility's risk, as it is a significant driver of earnings and cash flow  
18 that are of utmost importance to investors.<sup>56</sup> Investors and rating agencies  
19 understand that a constructive regulatory environment is critical to utilities' credit  
20 and financial integrity, especially during stressed market conditions. In fact, 50  
21 percent of the factors that weigh in Moody's ratings determinations relate to the

---

<sup>56</sup> Moody's Investors Service, Rating Methodology, Regulated Electric and Gas Utilities, at 8-11 (August 6, 2024).

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1 nature of regulation.<sup>57</sup> Predictability and consistency of regulatory actions are  
2 among the factors considered by Moody's in assessing the regulatory framework:

3 *As the revenues set by the regulator are a primary component of a*  
4 *utility's cash flow, the utility's ability to obtain predictable and*  
5 *supportive treatment within its regulatory framework is one of the most*  
6 *significant factors in assessing a utility's credit quality.*

7 \*\*\*

8 *In situations where the regulatory framework is less supportive, or is*  
9 *more contentious, a utility's credit quality can deteriorate rapidly.*<sup>58</sup>

10 Similarly, S&P observes that the regulatory environment in the jurisdictions where  
11 a utility operates is a "significant aspect of regulatory risk that influences credit  
12 quality".<sup>59</sup> S&P explains:

13 *[w]hen we evaluate U.S utility regulatory environments, we consider*  
14 *financial stability to be of substantial importance. Cash takes*  
15 *precedence in credit analysis. A regulatory jurisdiction that recognizes*  
16 *the significance of cash flow in its decision-making is one that will*  
17 *appeal to creditors.*<sup>60</sup>

18 Consequently, a utility that operates in a less predictable and more challenging  
19 regulatory environment is likely to be viewed as a riskier investment, and may result  
20 in lower credit ratings, constrained access to capital (particularly in volatile and  
21 adverse market environments), and higher costs of both debt and equity, all else  
22 equal. To meet the obligation to serve, it is in customers' best interests to ensure

---

57 Moody's Investors Service, Rating Methodology, Regulated Electric and Gas Utilities, at 2 (August 6, 2024).

58 Moody's Investors Service, Regulatory Frameworks – Ratings and Credit Quality for Investor-Owned Utilities, at 2 (June 18, 2010).

59 S&P Global Ratings, RatingsDirect, *Assessing U.S. Investor-Owned Utility Regulatory Environments*, at 2 (August 10, 2016).

60 S&P Global Ratings, RatingsDirect, *Assessing U.S. Investor-Owned Utility Regulatory Environments*, at 6 (August 10, 2016).



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1 that a utility has efficient access to capital on reasonable terms in all market  
2 environments.

3 **Q69. How do the credit rating agencies view the regulatory environment in which**  
4 **the Company operates?**

5 A69. The rating agencies view Michigan as a credit supportive regulatory environment  
6 and the Company's current credit ratings depend on the continued stability and  
7 predictability of Michigan's regulatory environment. Moody's explains that "DTE  
8 Electric's stable outlook reflects our expectation that the Michigan legislative and  
9 regulatory environments will remain credit supportive and enable the utility to  
10 recover the cost of, and earn a reasonable return on, prudently incurred capital  
11 investments and maintain a consistent financial profile."<sup>61</sup>

12  
13 An adverse change in Michigan's regulatory environment, such as an increase in  
14 regulatory lag, more contentiousness, insufficient cost recovery or authorized  
15 returns, or uncertainty in cost recovery, would increase DTE Electric's risk  
16 potentially leading to a credit downgrade to the detriment of customers.<sup>62</sup>

17

18 **Q70. Have you compared DTE Electric's regulatory risk relative to the electric**  
19 **utilities within the proxy group?**

20 A70. Yes, I have. The regulatory environment significantly affects both the access to  
21 and the cost of capital. Regulatory decisions regarding the authorized ROE and

---

61 Moody's Ratings, "Credit Opinion: DTE Electric Company Update to credit analysis," July 29, 2024, at 2.

62 Moody's Ratings, "Credit Opinion: DTE Electric Company Update to credit analysis," July 29, 2024, at 2.

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1 capital structure directly affect the subject utility's internal cash flow generation,  
2 and therefore the financial metrics reviewed by ratings agencies in their ratings  
3 assessments. Because credit ratings are intended to reflect the ability to meet  
4 financial obligations as they come due, the ability to generate the cash flows  
5 required to meet those obligations (and to provide a cushion for unexpected events)  
6 is of critical importance to both debt and equity investors.

7

8 To assess the regulatory environment of the proxy companies and DTE Electric, I  
9 reviewed the key cost recovery mechanisms and ratemaking frameworks for each of  
10 the electric operating companies within the proxy group in the jurisdictions in which  
11 they operate, including the cost recovery and volumetric risk mitigation mechanisms  
12 in place, test year, and rate base methodology.

13

14 As shown in Exhibit A-14 Schedule D5.8, like DTE Electric, all the proxy group  
15 operating companies with retail supply obligation have a fuel and/or purchased  
16 power cost recovery mechanism, 85 percent have a mechanism to recover energy  
17 efficiency program costs, and 68 percent have a capital cost recovery mechanism.  
18 Further, 51 percent of the proxy companies are able to use a full or partial forecast  
19 test year like the Company. However, unlike 59 percent of the proxy group, DTE  
20 Electric does not have a mechanism to mitigate volumetric risk, such as revenue  
21 decoupling or a lost revenue adjustment mechanism for its energy efficiency  
22 programs.

23

24 On balance, from an investor perspective, the regulatory mechanisms available to  
25 the Company do not offer a level of risk mitigation that is meaningfully different

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1 from the proxy companies. Furthermore, these regulatory mechanisms are only as  
2 effective as their implementation, including a compensatory return. It is in  
3 customers' best interest that the regulatory environment in Michigan be viewed as  
4 predictable, balanced, and supportive of utility investment.

5

6 **Q71. Do the Company's regulatory mechanisms reduce its risk relative to the proxy**  
7 **group?**

8 A71. No, they do not. The Company employs cost recovery mechanisms similar to those  
9 used by the proxy group; as such, its risk relative to the proxy group is not reduced  
10 as a result of its rate structures. Further, because the proxy companies all have  
11 similar mechanisms, any effects on the cost of equity associated with the rate  
12 mechanisms are captured in the analytical model results.

13

14 It is important to remember that risk assessment is a comparative exercise. Rate  
15 adjustment mechanisms are common in the industry and the financial community is  
16 fully aware of their prevalence. In fact, rate adjustment mechanisms have become  
17 more common in the industry, not less. As noted earlier, the proxy companies all  
18 have similar mechanisms available to them. While the specific details of the  
19 mechanics of the rate adjustment mechanisms may differ from utility to utility and  
20 jurisdiction to jurisdiction, their objective is the same: To improve the timeliness of  
21 cost recovery and mitigate (but not necessarily eliminate) earnings erosion  
22 associated with regulatory lag. Because the proxy companies all have mechanisms  
23 that improve the timeliness of cost recovery, the Company's regulatory mechanisms  
24 simply render it more comparable to its peers.

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1   **Q72. What are your conclusions regarding the effect of the Company's capital**  
2       **expenditure plans, its need to maintain access to capital, and the regulatory**  
3       **environment on its risk profile?**

4   A72. The Company's capital expenditure program reflects a near doubling of its net plant  
5       in service and significantly exceeds the cash generated from its operations, making  
6       regulatory support critical to DTE Electric's ability to finance and earn a reasonable  
7       return on its planned utility investments. The Company's capital expenditure plan  
8       emphasizes the importance of the Commission's decision in this proceeding, which  
9       will have a direct bearing on the Company's ability to maintain its financial profile  
10      and its access to the capital market at reasonable costs and terms.

11

12      The Company will need to rely on external sources of capital to fund critical  
13      generation and distribution investments to meet the aggressive clean energy  
14      requirements mandated under SB 271 and DTE Electric's significant distribution  
15      system requirements. In order to maintain access to external capital at reasonable  
16      costs and terms for customers in all market environments, the Company must have  
17      a reasonable opportunity to recover its full cost of service, including timely cost  
18      recovery of its capital investments and a competitive and compensatory return.

19

20   **V. Capital Structure**

21   **Q73. What is DTE Electric's requested capital structure?**

22   A73. As explained by Company Witness Timothy Lepczyk, the Company is requesting  
23       a permanent capital structure consisting of 50.75 percent equity and 49.25 percent  
24       long-term debt, consistent with its projected actual capital structure.

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1 **Q74. Please summarize the approaches to determining the appropriate capital**  
2 **structure for regulated utilities.**

3 A74. There are two primary approaches regulators use to determine the appropriate  
4 capital structure for ratemaking purposes. The most common approach is to use  
5 the subject utility's actual capital structure. This approach is preferred when the  
6 subject utility (1) issues its own debt, (2) has its own credit rating, and (3) its actual  
7 capital structure is within industry standards and practice.<sup>63</sup> When the subject utility  
8 does not issue its own debt and have its own credit rating, or when the actual capital  
9 structure deviates substantially from industry practice, a hypothetical capital  
10 structure may be imputed.

11

12 **Q75. Does DTE Electric issue its own debt and have its own credit rating?**

13 A75. Yes. Therefore, the next step is to assess the reasonableness of its actual capital  
14 structure within the context of industry practice.

15

16 **Q76. What are the regulatory guidelines for determining whether a utility's capital**  
17 **structure is consistent with sound utility practice?**

18 A76. In a 2020 publication titled *A Cost of Capital and Capital Markets Primer for*  
19 *Utility Regulators*, NARUC advises that actual capital structure ratios should be  
20 used unless they "greatly diverge" from sound industry practice:

21 *A utility management must be permitted latitude, discretion, and*  
22 *flexibility in managing capital structure ratios. Since there is no*  
23 *practical methodology to pinpoint theoretically optimal capital structure*  
24 *ratios, targeted ratios can only be broadly conceptualized. Appropriate*  
25 *ratios may shift over time as capital market conditions or business risk*  
26 *characteristics change. Additionally, the timing of upcoming issuances*

---

63 See, e.g., Parcell, D.C. (2020). *The Cost of Capital: A Practitioner's Guide*. Society of Utility and Regulatory Financial Analysts; 154 FERC ¶ 61,004, Docket No. ER15-945-001, at 15.

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1 *and maturities may influence the capital structure ratios because both*  
2 *the size and frequency of issuances are affected by the relative cost-*  
3 *effectiveness of various issuance increments.*

4 *Given these practical considerations, capital structure ratios cannot be*  
5 *deemed to be inappropriate unless the ratios greatly diverge from sound*  
6 *industry practice and cause a lack of financial flexibility that may lead*  
7 *to higher overall costs.*

8 \*\*\*

9 *As increasing financial leverage shifts the weight from common equity*  
10 *to lower cost debt, it also increases both the cost of debt and the cost of*  
11 *common equity. In practice, these offsetting impacts cancel each other*  
12 *out over a wide range of capital structure ratios”.<sup>64</sup>*

13 Further, James C. Bonbright explains in his seminal text *Principles of Public Utility*  
14 *Rates* that a hypothetical capital structure should be used only when actual capital  
15 structures are “clearly unsound” or “extravagantly conservative,” reasoning that  
16 using hypothetical capital structures “substitutes an estimate of what the capital cost  
17 would be under non-existing conditions for what it actually is or will soon be under  
18 prevailing conditions.”<sup>65</sup>

19

20 **Q77. How have you assessed whether DTE Electric’s capital structure is consistent**  
21 **with industry standards?**

22 A77. The proxy group has been selected to reflect comparable companies in terms of  
23 business and financial risks. Therefore, it is appropriate to compare the financial  
24 capital structures of the proxy group companies to the financial capital structure  
25 requested by DTE Electric in order to assess whether the Company’s capital  
26 structure is reasonable and consistent with industry standards for companies with

---

64 NARUC, *A Cost of Capital and Capital Markets Primer for Utility Regulators* (April 2020), at 12 (emphasis added).

65 James C. Bonbright, *Principles of Public Utility Rates*, at 243-44 (1960). Republished with permission by the Regulatory Assistance Project.

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1 commensurate risk. Company witness Lepczyk calculated the average capital  
2 structures for each of the proxy group operating companies in 2023, the most recent  
3 year for which data is available. Exhibit A-14 Schedule D1.1 demonstrates that the  
4 Company's projected common equity ratio of 50.75 percent is consistent with, yet  
5 somewhat lower than, the proxy group average equity ratio of 52.2 percent in 2023.

6

7 **Q78. What is your conclusion regarding the appropriateness of DTE Electric's**  
8 **capital structure in this proceeding?**

9 A78. Based on the analysis presented in Exhibit A-14 Schedule D1.1, I conclude that the  
10 Company's proposed permanent capital structure of 50.75 percent common equity  
11 and 49.25 percent long-term debt is consistent with sound industry practice and is  
12 not extravagantly conservative.

13

14 **Q79. Is the Company's requested capital structure balanced?**

15 A79. Yes. I understand that the Commission has long expressed a preference for a capital  
16 structure that "appropriately balance[s] the interests of the utility's investors and  
17 the customers," which it has recently interpreted as a capital structure consisting of  
18 equal parts debt and equity.<sup>66</sup> In my opinion, a balanced capital structure considers  
19 not only the proportions of debt and equity, but also the Company's risk profile, its  
20 financial and credit profile, its unique capital financing needs at a given time,  
21 capital market uncertainty, comparability of the capital structure to its peers, and  
22 the benefits and costs to customers. At any given time, a particular capital structure  
23 that is "balanced" in one market environment may become unbalanced in another.  
24 Given its substantial capital investment requirements, and the uncertain economic

---

66 See, e.g., Case No. U-21585, Final Order, at 231-232.

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1 environment in which it will need to raise capital going forward, it is critical that  
2 the Company have the financial flexibility to manage its capital structure as the  
3 market changes. In my opinion, a capital structure of 50.75 percent equity and  
4 49.25 percent long-term debt is not far removed from a 50/50 capital structure.  
5 Further, a 50.75 percent equity ratio is in the lower half of the range of the  
6 Company's peers. Therefore, the Company's requested capital structure does not  
7 diverge greatly from sound industry practice and is reasonable and appropriate.

8

9 **VI. Capital Market Environment**

10 **Q80. Do economic conditions influence the required Cost of Capital and required**  
11 **return on common equity?**

12 A80. Yes. The required cost of capital, including the ROE, is a function of prevailing  
13 and expected economic and capital market conditions. Each of the analytical  
14 models used to estimate the required ROE is influenced by current and expected  
15 capital market conditions. Therefore, an evaluation of current and projected market  
16 conditions is integral to any ROE recommendation.

17

18 **Q81. What are the key factors affecting the Cost of Equity for regulated utilities in**  
19 **the current and prospective capital markets?**

20 A81. The cost of equity for regulated utilities is currently affected by several key factors  
21 including (1) the interest rate environment and central bank monetary policy; (2)  
22 inflationary pressure and the longer-term outlook for inflation; and (3) greater  
23 market volatility and economic uncertainty associated with federal trade policy and  
24 a change in administration at the federal level. As discussed below, although the  
25 Federal Reserve reduced the Federal Funds rate in the fall of 2024 as inflation



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1 stabilized and moved closer to the central bank's two percent target, stubborn  
2 inflation and greater market and economic uncertainty has prompted the Federal  
3 Reserve to pause its easing of monetary policy. Consequently, interest rates and  
4 inflation have remained elevated and are expected to remain above the levels  
5 experienced prior to the COVID-19 pandemic. Lastly, the change in the federal  
6 administration and trade policy presents significant uncertainties with respect to the  
7 economic and capital market outlook in which DTE Electric will be raising external  
8 capital.

9

10 **Q82. Please summarize the changes in capital market conditions since early 2020.**

11 A82. The COVID-19 pandemic had wide ranging impacts on markets, affecting all  
12 market sectors, including utilities. At the start of the pandemic, both the S&P 500  
13 Index and the utility sector lost more than a third of its value.<sup>67</sup> At the same time,  
14 the Chicago Board Options Exchange ("CBOE") Volatility Index ("VIX", a  
15 measure of expected market volatility) tripled, from 25.03 on February 24, 2020,  
16 to 82.69 on March 16, 2020.<sup>68</sup>

17

18 Treasury bond yields declined rapidly as the stock market became extremely volatile  
19 and investors sought the relative safety of government bonds, combined with the  
20 Federal Reserve's reduction in the Federal Funds rate to a target range of 0 percent  
21 to 0.25 percent. Because bond yields and bond prices are inversely related, as  
22 demand for safer bonds increases, investors bid up the price of bonds and bid down  
23 the yields. Since the decline in bond yields was caused by investors' increased

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67 Source: Yahoo! Finance. Electric utility sector measured by the S&P 500 Utilities Index.

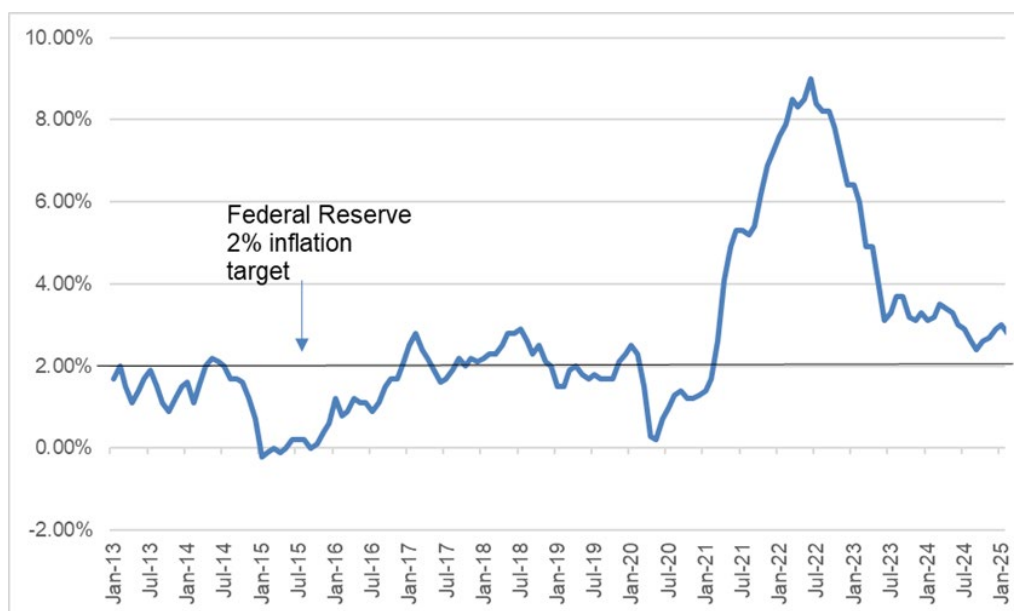
68 Source: Federal Reserve Bank of St. Louis FRED Database.

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aversion to equity market risk, the cost of equity did not decline commensurately with the decline in bond yields.

As the U.S. economy opened from the COVID-19 lockdowns, economic activity quickly rebounded, causing inflation to reach the highest levels seen in the last 40 years (*see* Figure 10 below).

**Figure 10. Year-Over-Year U.S. Consumer Price Index (2013-2025)<sup>69</sup>**



In response, the Federal Reserve tightened monetary policy at the fastest pace since the 1980s by increasing the Federal Funds rate by 525 basis points over the course of 11 consecutive Federal Open Market Committee (“FOMC”) meetings between March 2022 and July 2023. Although the pace of inflation subsided from its peak reached in June 2022, year-over-year inflation remained stubbornly above 3.0

<sup>69</sup> Source: U.S. Bureau of Labor Statistics.

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1 percent through the first half of 2024. In October 2024, the CPI reversed its  
2 downward trend, increasing 0.2 percent on a year-over-year basis, a trend that  
3 continued through January 2025. As of February 2025, annual CPI stood at 2.8  
4 percent.

5

6 **Q83. How have government and utility bond yields responded to the Federal**  
7 **Reserve’s monetary policy tightening?**

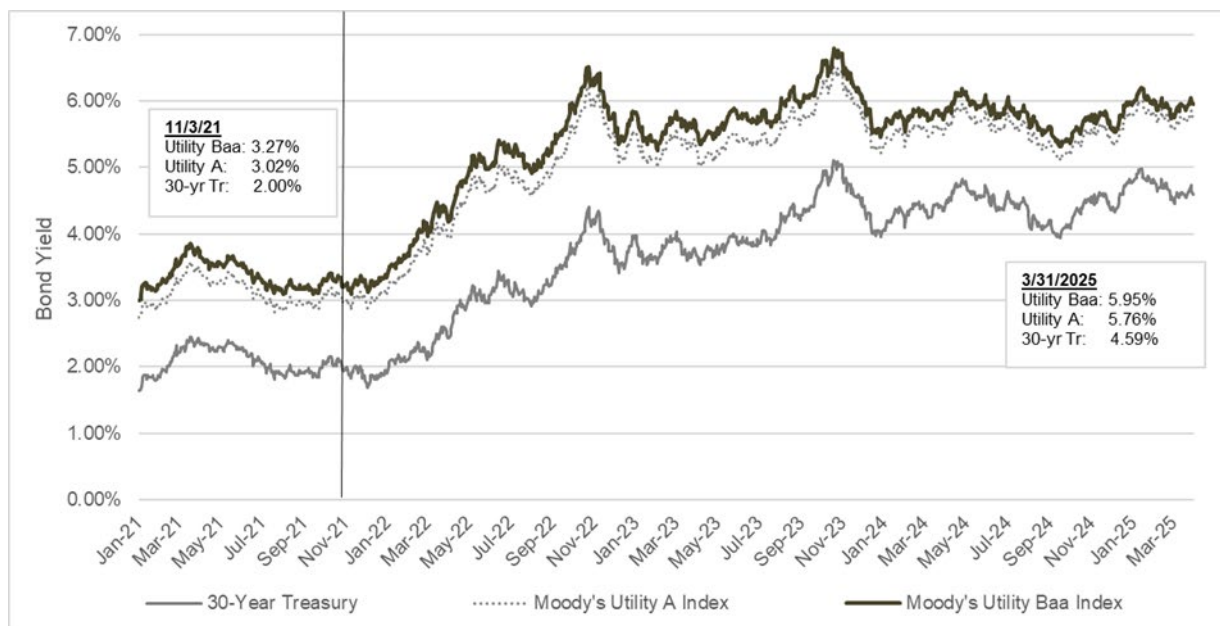
8 A83. As the U.S. economy improved in 2021 and the Federal Reserve moved  
9 aggressively to tighten monetary policy to fight stubbornly higher inflation,  
10 prevailing interest rates rose to their highest levels since 2010.<sup>70</sup> As shown in  
11 Figure 11 below, the 30-year Treasury yield has increased nearly 260 basis points  
12 since November 3, 2021 when the Federal Reserve signaled it would begin tapering  
13 its asset purchases. Utility bond yields have increased by approximately 270 basis  
14 points over the same period.

---

70 Source: Federal Reserve Bank of St. Louis, FRED Economic Database.

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1 **Figure 11. 30-Year Treasury Bond and Utility Bond Yields (2021-2025)<sup>71</sup>**



2  
3 Consensus forecasts from Blue Chip project long-term government and corporate  
4 bond yields to remain at current levels over the next six quarters.<sup>72</sup>

6 **Q84. Please explain how higher bond yields affect the ROE estimates.**

7 A84. The 30-year Treasury bond yield is a direct input to both the CAPM and the Risk  
8 Premium models because, as explained earlier, the term of the security aligns with  
9 the long life of natural gas utility assets. As yields increase, the cost of capital  
10 generally increases, and the ROE estimates from those two models also increase,  
11 although not on a one-to-one basis. Further, while interest rates are not a direct  
12 input to the DCF model, dividend yields on utility stocks must compete with yields  
13 on Treasury bonds. As interest rates on government bonds increase, utilities must  
14 offer a higher dividend yield to attract and retain investors, signaling an increase in

71 Source: Federal Reserve Bank of St. Louis, FRED Economic Database; Bloomberg Professional.

72 Blue Chip Financial Forecasts, Vol. 44, No. 4, April 1, 2025, at 1.

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1 the cost of equity for utilities. All else equal, higher dividend yields produce higher  
2 ROE estimates in the DCF model.

3

4 **Q85. How have economic and financial market conditions changed in recent**  
5 **months?**

6 A85. At the end of 2024, financial markets were optimistic that the Federal Reserve was  
7 close to attaining a “soft landing” by taming inflation without a consequential rise  
8 in unemployment. Over the past few months, however, federal policy uncertainty  
9 has climbed sharply, and financial market volatility has increased. Inflation and  
10 interest rates remain elevated, and the fears of an economic slowdown prompted by  
11 federal government workforce reductions and significantly lower government  
12 spending are growing.<sup>73</sup>

13

14 Expectations for inflation are markedly higher than in the five years prior to the  
15 pandemic. The University of Michigan’s February survey reported that U.S.  
16 consumer sentiment continued its decline with expectations of year-ahead inflation  
17 expectations increasing from 3.3 percent in January to 5.0 percent in March.<sup>74</sup>  
18 Longer-run inflation expectations rose from 3.5 percent in February to 4.1 percent  
19 in March. As noted in the March 2025 special report on inflation expectations:

20 *As of March 2025, long-run expectations have climbed sharply for three*  
21 *consecutive months and are now comparable to the peak readings from*  
22 *the post-pandemic inflationary episode. They exhibit substantial*

---

73 See, e.g., Blue Chip Financial Forecasts, Vol. 44, No. 4, April 1, 2025, at 2.

74 University of Michigan, Surveys of Consumers, accessed April 1, 2025.  
<http://www.sca.isr.umich.edu/>

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1 *uncertainty, particularly in light of frequent developments and changes*  
2 *with economic policy.*<sup>75</sup>

3

4 **Q86. How might changes in federal trade policy affect inflation and bond yields?**

5 A86. On February 1, 2025, President Trump issued an executive order implementing a  
6 25 percent additional tariff on imports from Canada and Mexico, and a 10 percent  
7 additional tariff on imports from China.<sup>76</sup> These tariffs were paused for 30-days  
8 and restored on March 4, 2025. Two days later, President Trump temporarily  
9 paused tariffs imposed on approximately half of imports from Canada and 38  
10 percent of imports from Mexico until April 2<sup>77</sup>. Further, on February 10, President  
11 Trump restored a 25 percent tariff on steel and increased the tariff on aluminum to  
12 25 percent.<sup>78</sup> On March 24, 2025, the White House announced it would implement  
13 a 25 percent tariff on all goods from any country that imports Venezuelan oil,  
14 whether directly or indirectly.<sup>79</sup> Lastly, on April 2, 2025, President Trump  
15 announced the administration would impose a 10 percent base tariff on all imports  
16 from nearly every country plus an additional tariff customized for each of  
17 approximately 60 countries.<sup>80</sup> Although the effect of these tariffs on the economy

---

75 University of Michigan, Surveys of Consumers, March 2025 Update: Current versus Pre-Pandemic Long-Run Inflation Expectations (March 28, 2025)  
<https://data.sca.isr.umich.edu/fetchdoc.php?docid=78367>

76 <https://www.whitehouse.gov/fact-sheets/2025/02/fact-sheet-president-donald-j-trump-imposes-tariffs-on-imports-from-canada-mexico-and-china/>

77 <https://www.whitehouse.gov/presidential-actions/2025/03/amendment-to-duties-to-address-the-flow-of-illicit-drugs-across-our-southern-border/>; <https://www.whitehouse.gov/presidential-actions/2025/03/amendment-to-duties-to-address-the-flow-of-illicit-drugs-across-our-northern-border-0c3c/>

78 <https://www.whitehouse.gov/fact-sheets/2025/02/fact-sheet-president-donald-j-trump-restores-section-232-tariffs/>

79 <https://www.whitehouse.gov/presidential-actions/2025/03/imposing-tariffs-on-countries-importing-venezuelan-oil/>

80 <https://www.whitehouse.gov/presidential-actions/2025/04/regulating-imports-with-a-reciprocal-tariff-to-rectify-trade-practices-that-contribute-to-large-and-persistent-annual-united-states-goods-trade-deficits/>

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1 is uncertain, economists generally agree that higher tariffs increase inflation by  
2 increasing the cost of consumer goods. The tariffs could lead to higher inflation  
3 and reduce overall demand, as well as higher interest rates and a stronger dollar.<sup>81</sup>  
4 The Budget Lab at Yale University estimates that these tariffs would raise  
5 consumer prices by 1.4 to 5.1 percent before substitution, which would be the  
6 equivalent of the cost of \$1,900 to \$7,600 in disposable income for the average  
7 household.<sup>82</sup>

8

9 In a recent article published by S&P Global Market Intelligence, economists noted  
10 the “enormous uncertainty” associated with the effect of tariffs on inflation and the  
11 economy, but projected that if President Trump’s tariffs are imposed as proposed,  
12 they “would cause the core consumer price index<sup>83</sup> to run at a 6% annual pace on  
13 average over the next two years”.<sup>84</sup>

14

15 Higher inflation could complicate the Federal Reserve’s unwinding of restrictive  
16 monetary policies,<sup>85</sup> as well as increase long-term bond yields like the 30-year  
17 Treasury yield. The FOMC paused its cuts in the Federal Funds rate at its January  
18 2025 meeting, citing elevated inflation and a stable labor market, and held rates  
19 steady at its March 2025 FOMC meeting. In an April 4, 2025 speech, Federal

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81 J.P. Morgan Asset Management, Market Insights “2025 Year-Ahead Investment Outlook,” November 21, 2024.

82 Yale Budget Lab, “Fiscal, Macroeconomic, and Price Estimates of Tariffs Under Both Non-Retaliations and Retaliations Scenarios,” October 16, 2024.

83 As measured by the Personal Consumption Expenditures (“PCE”) price index.

84 S&P Global Market Intelligence, “Tariffs projected to push US inflation near 2022 highs,” April 9, 2025.

85 See, e.g., S&P Global Market Intelligence, “Tariffs projected to push US inflation near 2022 highs,” April 9, 2025.

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1 Reserve Chair Jerome Powell stated that the outlook is “highly uncertain” and the  
2 tariff proposals were “significantly larger than expected” that are likely to result in  
3 higher inflation and slower growth.<sup>86</sup>

4  
5 Longer-term bonds like the 30-year Treasury bond are more sensitive to inflation  
6 expectations than shorter-term bonds because their value is influenced more by  
7 inflation due to their longer maturity holding period and reinvestment rate  
8 implications. Thus, as the value (price) of bonds declines due to higher inflation  
9 expectations, the yield increases. Because utilities are capital intensive enterprises,  
10 higher inflation and interest rates tend to have a negative effect on utility stocks. If  
11 realized, higher inflation and interest rates would suggest that the cost of capital for  
12 utilities may increase in the future.

13

14 **Q87. Has market volatility increased in recent months?**

15 A87. Yes. As noted earlier, the VIX is a measure of expected equity market volatility.<sup>87</sup>  
16 As shown in Figure 12, the VIX has been on an increasing trend since January 2024.  
17 Further, after President Trump’s tariff announcement on April 2, 2025, the VIX  
18 climbed to levels not seen since 2020 when the COVID-19 pandemic was spreading  
19 across the country. Higher market volatility indicates an increase in equity market

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86 Chair Powell’s speech at the Society for Advancing Business Editing and Writing Annual Conference, Arlington, Virginia, April 4, 2025, <https://www.federalreserve.gov/newsevents/speech/powell20250404a.htm>

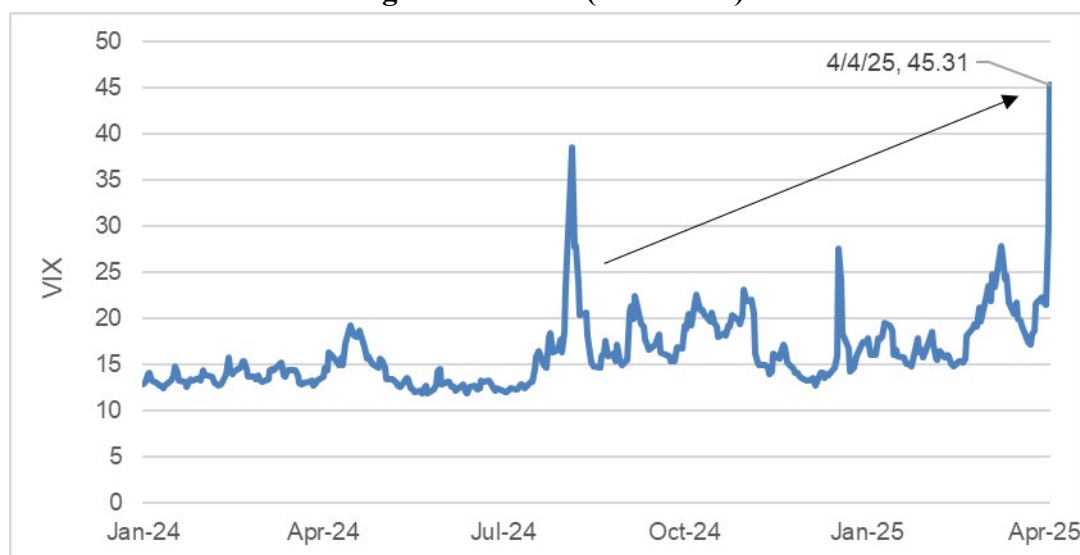
87 The VIX is a benchmark index to measure the market’s expectation of future volatility. The VIX Index is based on options of the S&P 500® Index, considered the leading indicator of the broad U.S. stock market. The VIX Index is recognized as the world’s premier gauge of U.S. equity market volatility. Source: Chicago Board of Options Exchange, [https://www.cboe.com/tradable\\_products/vix/](https://www.cboe.com/tradable_products/vix/)



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1 risk and as market risk rises, so does the cost of equity since equity investors require  
2 higher returns to compensate them for greater market risk.

3  
4 **Figure 12. VIX (2024-2025)<sup>88</sup>**



5  
6  
7 **Q88. What conclusions do you draw from your review of the current capital market**  
8 **environment and the implications on the Company's cost of equity?**

9 A88. Over the last five years, the economic and financial market environment has  
10 operated under heightened uncertainty associated with the COVID-19 pandemic,  
11 the war in Ukraine, stubborn inflation, and more recently, uncertainty surrounding  
12 the economy and federal trade policy. The effect of the new presidential  
13 administration on the economy is uncertain, and higher tariffs could complicate  
14 investor expectations for inflation and interest rates. Although the Federal Reserve  
15 responded to easing inflation by cutting rates in late 2024, it has since paused those  
16 cuts to assess how the effects of fluctuating trade policies affect the economy.  
17 These factors underscore the importance of using multiple models when

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88 Source: Federal Reserve Bank of St. Louis FRED Economic Data.

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1 determining DTE Electric's cost of equity to gain a comprehensive perspective of  
2 the effect of fluid and evolving market conditions on the cost of equity.

3

4 **VII. Conclusions and Recommendation**

5 **Q89. What is your recommendation regarding the Company's cost of equity and**  
6 **capital structure in this proceeding?**

7 A89. As discussed throughout my Direct Testimony, it is important to consider a variety  
8 of quantitative and qualitative information in reviewing analytical results and  
9 arriving at ROE determinations. Based on my review of the results from three  
10 commonly used analytical approaches, I conclude an ROE in the range of 9.90  
11 percent to 11.60 percent represents the range of equity investors' required return  
12 for investment in electric utilities comparable to DTE Electric in today's capital  
13 market environment. Within that range, an ROE at the midpoint of 10.75 percent  
14 is reasonable.

15 As to the capital structure, I believe that the Company's requested permanent capital  
16 structure of 50.75 percent common equity and 49.25 percent long-term debt is within  
17 the range of capital structures that finance the regulated electric utility operations of  
18 the proxy group and, therefore, is reasonable and appropriate.

19

20 **Q90. Does this conclude your direct testimony?**

21 A90. 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-21860

QUALIFICATIONS  
  
AND  
  
DIRECT TESTIMONY  
  
OF  
  
MARKUS B. LEUKER

**DTE ELECTRIC COMPANY**  
**QUALIFICATIONS AND DIRECT TESTIMONY OF MARKUS B. LEUKER**

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

2   A1.   My name is Markus B. Leuker (he/him/his). My business address is: One Energy  
3           Plaza, Detroit, Michigan 48226. I am Director of Load Management and  
4           Forecasting in the Business Planning and Development organization.

5

6   **Q2.   On whose behalf are you testifying?**

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

8

9   **Q3.   What is your educational background?**

10   A3.   I received a Bachelor of Science in Business Administration from Xavier  
11           University in Cincinnati, Ohio with a concentration in Marketing and Management  
12           in 1991. I received a Master of Business Administration from Xavier University in  
13           Cincinnati, Ohio in 1998. I have also completed several Company sponsored  
14           courses and attended various seminars to further my professional development.

15

16   **Q4.   What is your work experience?**

17   A4.   I joined the Company in November 2010 as Manager, Corporate Energy  
18           Forecasting. Prior to DTE Electric, I worked for IHS/CSM Worldwide as a Sr.  
19           Manager, North American Advisory Services where I led the pursuit, development,  
20           execution and delivery of key client projects. Some of my experiences at IHS/CSM  
21           Worldwide included: Market Research & Analysis, Market Opportunity Analysis,  
22           Business Modeling and Strategic Analysis, Regulatory Market Assessment, and  
23           Financial and Scenario Analysis. In addition to my experience with DTE Electric,  
24           I worked as North American Manager, Market Research & Analysis for Visteon  
25           Corporation where I managed global coordination of the research function and led

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1 a team of researchers in various studies including customer and competitor  
2 research, new product creation, and customer satisfaction. I have also had prior  
3 experience in the utility industry working as a Senior Analyst at Cinergy  
4 Corporation (currently Duke Energy). While at Cinergy, I worked on various non-  
5 regulated and regulated marketing activities.

6

7 **Q5. What is your current position and responsibilities?**

8 A5. In 2024 I was promoted to Director of Load Management and Forecasting. In this  
9 position I am responsible for overseeing DTE Electric's Demand Response (DR)  
10 portfolio, which includes short- and long-term strategic development, marketing  
11 and management of DR programs and pilots. I am responsible for overseeing the  
12 economic and electric sales forecasting activities for DTE Electric. These activities  
13 include data collection, statistical analysis of data, forecast model building, the  
14 economic forecast that supports the sales forecast, and interaction with other  
15 departments on forecast-related activities. I am also responsible for overseeing the  
16 operations of DTE's Retail Access program. This includes the billing of  
17 Transmission charges for Retail Access customers, completing MPSC filings per  
18 the Retail Access tariff, administering the 10% Cap and Queue list customers, and  
19 coordinating with third-party Alternative Energy Suppliers to complete these  
20 activities.

21

22 **Q6. Do you hold any certifications or are you a member of any professional**  
23 **organizations?**

24 A6. I am a member of Edison Electric Institute's (EEI) Load Forecasting Group (LFG).  
25 The LFG's purpose is to enhance load forecasting capabilities by exchanging

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1 information among the group's base of experienced and knowledgeable load  
2 forecasters. I am also a member of the Detroit Association for Business Economics  
3 (DABE). DABE discusses economic issues affecting Southeastern Michigan.

4

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

7 A7. Yes. I have sponsored testimony and exhibits before the MPSC in the following  
8 DTE Electric cases:

| 9  | <u>Case No.</u> | <u>Description</u>                          |
|----|-----------------|---------------------------------------------|
| 10 | U-17049         | 2012 Energy Optimization Plan               |
| 11 | U-17097         | 2013 Power Supply Cost Recovery (PSCR) Plan |
| 12 | U-17302         | 2013 Renewable Energy Plan Update           |
| 13 | U-17319         | 2014 PSCR Plan                              |
| 14 | U-17680         | 2015 PSCR Plan                              |
| 15 | U-17762         | 2016-17 Energy Optimization Plan            |
| 16 | U-17767         | DTE Electric General Rate Case              |
| 17 | U-17793         | 2015 Renewable Energy Plan                  |
| 18 | U-17920         | 2016 PSCR Plan                              |
| 19 | U-18014         | DTE Electric General Rate Case              |
| 20 | U-18111         | 2016 Amended Renewable Energy Plan          |
| 21 | U-18143         | 2017 PSCR Plan                              |
| 22 | U-18255         | DTE Electric General Rate Case              |
| 23 | U-18262         | 2018-19 Energy Waste Reduction Plan         |
| 24 | U-18403         | 2018 PSCR Plan                              |
| 25 | U-18419         | 2017 Certificate of Necessity               |

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|    |         |                                     |
|----|---------|-------------------------------------|
| 1  | U-18232 | 2018 Renewable Energy Plan          |
| 2  | U-20162 | DTE Electric General Rate Case      |
| 3  | U-20221 | 2019 PSCR Plan                      |
| 4  | U-20471 | 2019 Integrated Resource Plan (IRP) |
| 5  | U-20561 | DTE Electric General Rate Case      |
| 6  | U-18232 | 2020 Amended Renewable Plan         |
| 7  | U-20836 | 2022 DTE Electric Rate Case         |
| 8  | U-21193 | 2022 Integrated Resource Plan       |
| 9  | U-21297 | 2023 DTE Electric Rate Case         |
| 10 | U-21534 | 2024 DTE Electric Rate Case         |

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1 **Purpose of Testimony**

2 **Q8. What is the purpose of your testimony?**

3 A8. The purpose of my testimony is to provide the Company's current electric sales,  
4 maximum demand and system output forecast for the period 2025-2029, including  
5 the projected 12-month test period January 1, 2026 through December 31, 2026. I  
6 will discuss the outlook for the national and local economy which is the basis of  
7 the forecast. I will describe how the forecast of electric sales, maximum demand  
8 and system output is developed. My testimony will support the reasonableness of  
9 the electric sales forecast used by DTE Electric in this proceeding.

10

11 I will also provide an overview of DR and the regulatory framework of DR. I will  
12 then discuss the evolving DR landscape and the Company's current DR portfolio  
13 before further discussing the investments needed for DR. I will conclude with  
14 discussing the benefits of continuing the Company's robust DR portfolio.

15

16 **Q9. How is your testimony organized?**

17 A9. My testimony consists of the following ten parts:

- |    |           |                                                           |
|----|-----------|-----------------------------------------------------------|
| 18 | Part I    | Economic Outlook                                          |
| 19 | Part II   | Forecast Development and Assumptions                      |
| 20 | Part III  | Historical and Current Electric Forecast Sales and Demand |
| 21 | Part IV   | Electric Load Forecast Accuracy                           |
| 22 | Part V    | Demand Response Overview                                  |
| 23 | Part VI   | DR Regulatory Framework                                   |
| 24 | Part VII  | DR Portfolio                                              |
| 25 | Part VIII | Evolving DR Landscape                                     |



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1 Part IX DR Portfolio Investments

2 Part X DR Benefits

3

4 **Q10. Are you sponsoring any exhibits in this proceeding?**

5 A10. Yes. I am sponsoring in whole, or in part, the following exhibits:

6 Exhibit Schedule Description

7 A-5 E1 Annual Sales by Major Customer Classes and System  
8 Output 2019-2023 Historical

9 A-12 B5.6 Capital Expenditures – Demand Response Portfolio

10 A-13 C5.9 Demonstrating and Selling Expenses-DR (line 9)

11 A-15 E1 Annual Sales by Major Customer Classes and System  
12 Output 2024 Historical; 2025-2029 Forecast

13 A-15 E2 Annual System Output, Maximum Demand and Load  
14 Factor

15 A-15 E3 Projected Period Known and Measurable Changes to  
16 Sales

17 A-15 E4 Summary of Economic Outlook

18 A-15 E5 Variance of Weather-Normalized Electric Sales and Peak  
19 and ITRON's Benchmarking Survey Results

20 A-15 E6 Annual Customer Counts by Major Customer Classes  
21 2019-2024 Historical 2025-2029 Forecast

22

23 **Q11. Were these exhibits prepared by you or under your direction?**

24 A11. Yes, they were.

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1 **Part I: Economic Outlook**

2 **Q12. What was the condition of the national economy in 2024?**

3 A12. Real gross domestic product increased at an annualized rate of 1.6% in the first  
4 quarter, 3.0% in the second, and 2.8% in the third. Real personal consumption  
5 expenditures increased at an annualized rate of 1.6% in the first quarter, 2.8% in  
6 the second, and 3.5% in the third. Real disposable personal income increased at an  
7 annualized rate of 5.6% in the first quarter, 1.0% in the second, and 0.8% in the  
8 third. The Consumer Price Index for All Urban Consumers (CPI-U) grew at an  
9 annualized rate of 3.8% in the first quarter, 2.8% in the second, and 1.2% in the  
10 third. Seasonally adjusted housing starts declined at an annualized rate of 18.5% in  
11 the first quarter, 17.6% in the second, and 2.7% in the third. Light vehicle  
12 production was 2.7 million in the first quarter and 2.7 million in the second.

13

14 **Q13. What is the outlook for the nation's economy in 2025 and 2026?**

15 A13. Gross domestic product is expected to increase by 1.7% in 2025 and by 1.7% in  
16 2026. Disposable personal income is expected to increase by 3.0% in 2025 and by  
17 2.9% in 2026. Personal consumption expenditures are expected to increase by 2.0%  
18 in 2025 and by 2.0% in 2026. These measures from the national income and product  
19 accounts are in real terms, meaning that inflation has been removed from them. The  
20 CPI-U is forecast to increase by 2.4% in 2025 and by 2.5% in 2026. Total light  
21 vehicle production in the United States is forecast to reach 10.6 million units in  
22 2025 and 10.7 million in 2026. The national economic forecast was completed in  
23 2024 before extensive tariffs were enacted.

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1   **Q14.   What is the outlook for Southeast Michigan’s economy in 2025 and 2026?**

2   A14.   Total non-farm employment is forecast to increase by 0.4% in 2025 but decrease  
3           by 0.3% in 2026. Natural resources, mining, and construction employment is  
4           expected to decline by 0.1% in 2025 then increase by 1.1% in 2026. Total private  
5           non-manufacturing employment is forecast to increase by 1.0% in 2025 and by  
6           0.1% in 2026. In the government sector, employment is expected to rise by 0.5%  
7           in 2025 and by 0.6% in 2026. Southeast Michigan automotive production is  
8           expected to reach a level of 1.3 million vehicles in 2025 and 1.3 million in 2026.  
9           Population is forecast to increase by 0.12% in 2025 and by 0.0% in 2026. As with  
10          the national forecast, the Michigan economic forecast was completed in 2024  
11          before tariffs were enacted.

12

13   **Part II: Forecast Development and Assumptions**

14   **Q15.   What is the general approach used in developing the forecast of DTE Electric’s**  
15          **service area electric sales and system output?**

16   A15.   The general approach reflects widely accepted industry standards for electricity  
17          forecasting. Using this approach has resulted in high accuracy rates when  
18          comparing forecasted DTE Electric service area electric sales to actual historical  
19          annual sales. Forecast accuracy is discussed in more detail in Part IV of my  
20          testimony.

21

22          Most customer class sales and customer forecasts are built from linear regression  
23          models that relate monthly sales to economic activity, weather, changes in end-use  
24          saturation, and energy efficiency. The forecast is developed separately for each  
25          major rate classification: Residential, Commercial and Industrial (C&I), and other.  
26          The residential sales forecast is derived by combining a use-per-customer forecast,

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1 using a statistically adjusted end-use (SAE) specification, with a customer forecast.  
2 Separate models are estimated for small and large C&I customers. Small C&I,  
3 comprised of over 200,000 small business customers, is modeled similarly to  
4 residential, while large C&I, comprised of over 3,000 high consumption large  
5 business customers, is forecast using econometric models unique to seven super  
6 sectors. The other (street lighting) forecast is provided by Company Witness  
7 Hartley. The system output is forecasted as the sum of the electric sales values and  
8 the projected system losses.

9

10 There are many factors that impact the sales and customer forecasts for each  
11 customer class. Examples of forecast drivers include:

- 12 • National, state, and local economic projections provided by sources  
13 including, but not limited to: S&P Global (formerly IHS Markit) and Moody's  
14 Analytics
- 15 • The Energy Information Administration (EIA) Annual Energy Outlook  
16 (AEO) 2023 end-use intensity and end-use saturation estimates for the East  
17 North Central Census Division (modified to reflect DTE Electric's end-use  
18 information)
- 19 • Historical weather data from the Detroit Metropolitan Airport, with normal  
20 weather assumptions in the forecast horizon
- 21 • DTE Electric's Energy Waste Reduction (EWR) targets
- 22 • DTE Electric's behind-the-meter distributed generation (DG) projections
- 23 • DTE Electric's electric vehicle (EV) forecast for light-duty and fleet vehicles

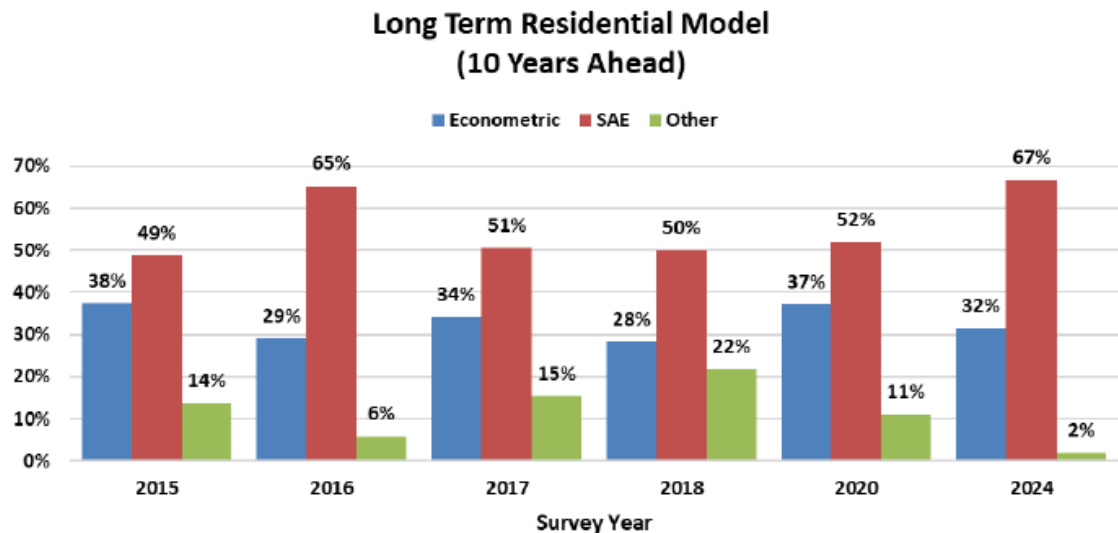
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- Large customer load adjustments (incremental expansions or losses) that would not be reflected in the historical data or economic projections

**Q16. Why is regression modeling the primary method the Company uses to forecast?**

A16. Regression modeling (including both standard econometric and SAE) is not only the preferred approach from the Company but also from peer utilities (98% of utilities as of 2024) as seen in Figure 1. Additionally, the Commission has approved regression modeling as a form of sales forecasting since as early as 2003<sup>1</sup>.

**Figure 1 : Itron Forecasting Benchmark Survey  
(Long Term Residential Forecast Model Method)**



Regression modeling offers quantitative insights into the relationships between variables, crucial for understanding long-term trends. For instance, it can quantify

<sup>1</sup> <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068t0000000vMiiAAE>

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1 the impact of weather variations, economic conditions, and changes in appliance  
2 adoption on electricity consumption. Properly specified and validated regression  
3 models provide accurate and reliable forecasts. Their flexibility to incorporate  
4 multiple predictors helps capture the complexity of real-world variations in  
5 electricity usage.

6  
7 **Q17. What other forms of long-term forecasting exist and why are they not utilized?**

8 A17. Some other forms of forecasting include but are not limited to:

- 9 • Basic end-use models incorporate factors driving energy usage such as  
10 appliance adoption and energy efficiency without a regression step. While  
11 these models excel at explaining the end-use factors influencing energy  
12 consumption, they often fall short in accounting for variations due to  
13 weather, seasonality, or economic conditions.
- 14 • Time series analysis, including trend and compound annual growth rate  
15 (CAGR), involves examining historical data to identify patterns and trends  
16 for forecasting. While this method is straightforward and easy to  
17 understand, it tends to be simplistic. Trend analysis merely quantifies  
18 trends without explaining the underlying causes. Additionally, it assumes  
19 that historical patterns will continue unchanged into the future.
- 20 • Machine learning involves analyzing large datasets to identify patterns and  
21 make predictions. While this method is valuable for forecasting, it often  
22 operates as a "black box," making it difficult to understand and dissect.  
23 Additionally, it lacks the combination of qualitative and quantitative  
24 insights that regression modeling provides.

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1 **Q18. What standards are used to evaluate the results of the regression models?**

2 A18. A variety of statistical tests and metrics are used to evaluate the effectiveness of a  
3 regression model. These include, but are not limited to:

- 4 • Adjusted R-squared indicates how well the model explains variations in  
5 historical data. A high R-squared value boosts confidence in the model's  
6 predictive power and its ability to reliably forecast future values. Typically,  
7 the company seeks R-squared values of 0.90 or higher, meaning 90% of the  
8 variation in electricity usage is explainable.
- 9 • Mean Absolute Percentage Error (MAPE) is a metric used to measure the  
10 accuracy of a forecasting model. The company uses both in-sample and out-  
11 of-sample MAPEs to evaluate model performance. Generally, MAPE  
12 values of 3% or less are considered indicative of good models.
- 13 • The Durbin-Watson (DW) statistic detects autocorrelation in regression  
14 model residuals. High or low DW scores suggest consistent over- or under-  
15 forecasting. The company aims for DW scores between 1.5 and 2.5.
- 16 • T-statistics determine the significance of independent variables in a  
17 regression model, assessing their impact on the dependent variable.  
18 Generally, a t-statistic of  $\pm 2$  is considered good.
- 19 • The p-value determines the statistical significance of each independent  
20 variable, assessing whether the relationship with the dependent variable is  
21 genuine or could have occurred by chance. P-values less than 5% are  
22 commonly used as thresholds for significance.

23

24 While the company strives to meet each criterion, deviations are sometimes  
25 acceptable based on other considerations within the outlined parameters.

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1   **Q19. Can you please describe the data used to construct the forecast models?**

2   A19. Each model used to forecast sales was estimated with monthly historical  
3       consumption data beginning in January 2006, with estimation ending in June 2024.  
4       Customer count forecast models were estimated with monthly historical customer  
5       count data beginning in January 2012, with estimation ending in June 2024.

6

7       The forecast for both sales and customers was extended through 2029 and used to  
8       develop the long-term system energy and peak demand forecast.

9

10       A bottom-up hourly load model, described later in my testimony, utilized hourly  
11       historical customer class level data as the basis for developing a suite of load  
12       profiles that were used to forecast the peak demand.

13

14   **Q20. How is weather applied in the load forecast?**

15   A20. Weather is one of the primary variables used in each customer class forecast model.  
16       In each model, actual weather, measured in the form of heating degree days (HDDs)  
17       and cooling degree days (CDDs) is used to understand the unique relationship that  
18       a customer class's energy consumption has with weather. HDDs are calculated by  
19       subtracting average daily temperature from a defined base such as 65 degrees  
20       Fahrenheit. Conversely, CDDs are calculated by subtracting the base, from average  
21       daily temperature.

22

23       In regression modeling, a coefficient is calculated to quantify this impact. Once the  
24       coefficient is calculated, it is applied to the weather assumed in the forecast horizon.



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1 In the forecast horizon, normal weather is assumed as the most prudent form of  
2 future weather expectations.

3

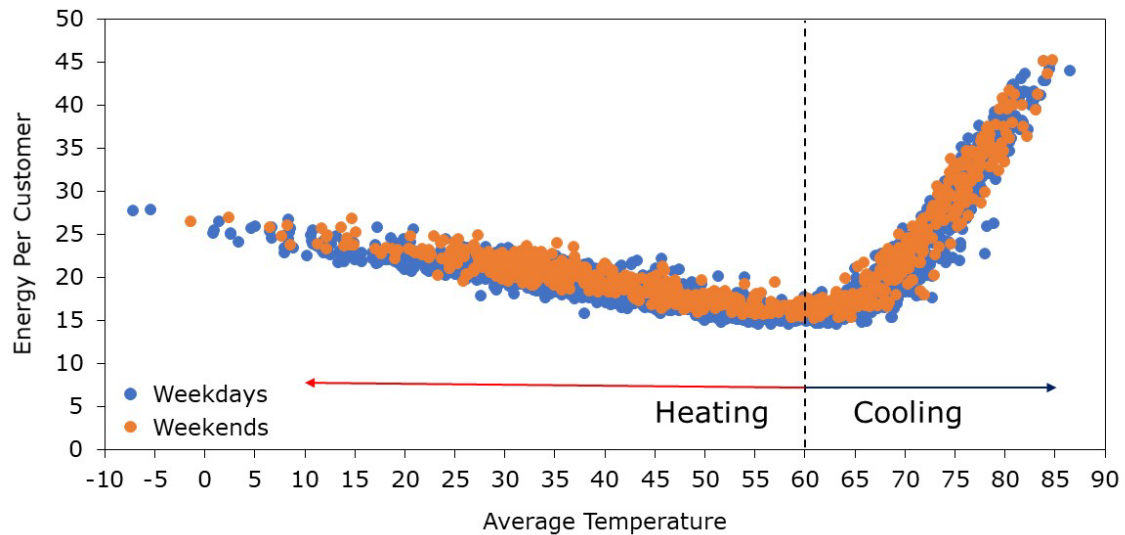
4 **Q21. Can you please describe the HDD and CDD bases used in the forecast?**

5 A21. Yes. As seen in Figures 2 and 3, weather impact is different depending on the  
6 customer class. Residential sales are more impacted by weather and customers  
7 typically begin cooling their buildings at an average temperature of 60 degrees.  
8 Small C&I sales are not as influenced by weather, although customers typically  
9 begin cooling their buildings at an average of 50 degrees. The relationships to  
10 weather are also non-linear, creating a need to utilize multiple HDD and CDD bases  
11 to accurately capture the weather response. HDD and CDD bases, represented by  
12 the name and temperature of the base, for each customer class include:

- 13 • Residential: HDD25, HDD60, CDD60, CDD65, CDD70 and CDD75
- 14 • Small C&I: HDD50, CDD50, CDD60, and CDD70
- 15 • Large C&I (varies by super sector):
  - 16 ▪ Education and Health: CDD50
  - 17 ▪ Transportation, Trade and Utilities (TTU): HDD50 and CDD50
  - 18 ▪ Offices: HDD45 and CDD55
  - 19 ▪ Other Markets: HDD45 and CDD55
  - 20 ▪ Automotive: HDD50 and CDD60
  - 21 ▪ Other Manufacturing: CDD55

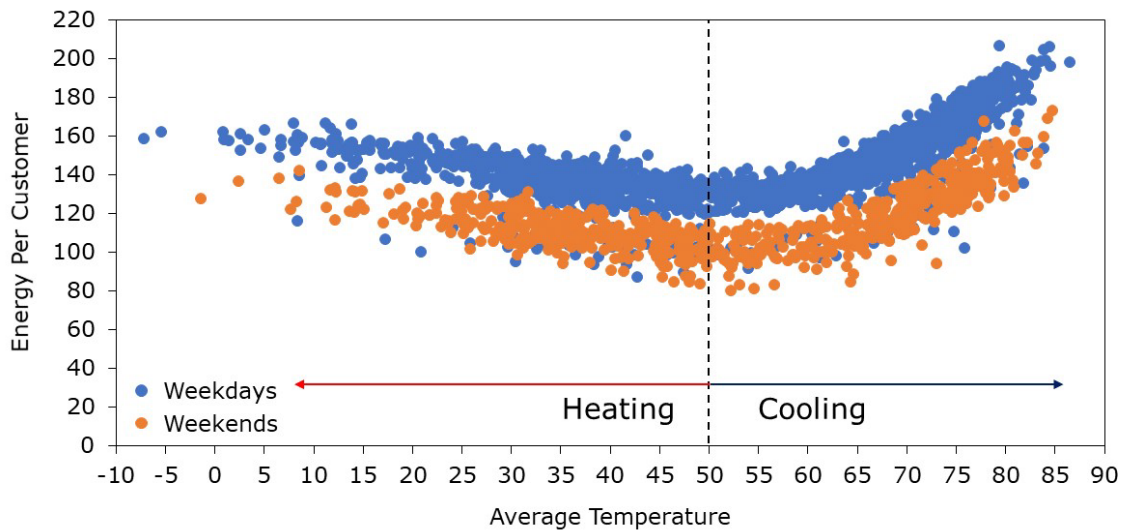
1

**Figure 2 : Residential Daily Use-Per-Customer vs Temperature**



2

**Figure 3 : Small C&I Daily Use-Per-Customer vs Temperature**



3

4 **Q22. How does DTE Electric define normal weather?**

5 A22. DTE Electric defines normal weather as a 15-year average of historical values,  
6 updated on an annual cadence as recommended by the Commission in Case No. U-  
7 20471. In this instant case, 2009-2023 is the timeframe for normal weather.  
8 Additionally, historical actual sales in my Exhibits were weather normalized with

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1 the same normal weather assumed in the forecast for comparison purposes. Daily  
2 average temperature is converted to HDDs and CDDs for various bases and  
3 averaged across years. As a result, this process calculates and defines normal HDDs  
4 and CDDs for various bases in a given day, month, and year.

5

6 **Q23. How was the Residential class forecast developed?**

7 A23. Electricity sales in the residential class were forecast using the SAE model which  
8 specifies energy use as a function of 22 end-uses, including DG and EV demand,  
9 along with factors that affect the end-use requirements, such as economic activity  
10 and weather. The residential class forecast begins with a standard end-use model,  
11 with appliance saturation projections and average electricity usage per end-use  
12 provided by a Company-conducted residential appliance saturation survey and the  
13 EIA's AEO 2023 for the East North Central region in which DTE Electric operates.  
14 Residential EWR programs are applied directly to the corresponding end-uses in  
15 the SAE model. The combination of appliance saturations and average electricity  
16 per end-use is indexed and calibrated to the Company's usage per customer for a  
17 base year to create an electricity forecast for each end-use.

18

19 Utilization variables, which explain how much an end-use is utilized, are combined  
20 with end-use intensities. For residential, the primary variables used to explain  
21 utilization are weather, real personal income, population, households, and  
22 workplace occupancy. The utilization variables are then combined with the end-  
23 use intensities to compute three explanatory variables that are:

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- 1           • XHeat – An aggregated heating variable that captures changes in heating end-  
2           use saturation and efficiency, and combined with HDDs, economic, and other  
3           factors that impact the utilization of heating equipment.
- 4           • XCool – An aggregated cooling variable that captures changes in cooling end-  
5           use saturation and efficiency, and combined with CDDs, economic, and other  
6           factors that impact the utilization of cooling equipment.
- 7           • XOther – An aggregated base-load variable that captures changes in base-  
8           load end-use saturation and efficiency, and combined with number of days in  
9           a month, economic, and other factors that impact the utilization of base-load  
10          equipment.

11

12          Along with seasonal factors, the resulting explanatory variables are then regressed  
13          against the Company's residential monthly use per customer sales. The model  
14          effectively acts as the statistical adjustment and calibrates the end-use forecast to  
15          the Company's historical sales.

16

17          The number of residential customers was forecasted using historical and projected  
18          households for southeast Michigan provided by S&P Global. Customer counts are  
19          modeled using a regression, with households as the primary explanatory variable.  
20          The customer forecast is then multiplied by the use per customer from the SAE  
21          model to produce the total residential class sales forecast.

22

23          **Q24. How was the small C&I forecast developed?**

24          A24. Similar to the residential class forecast, small C&I class sales are also forecast using  
25          an SAE model, utilizing 11 end-uses including DG and EV demand. Additionally,

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- 1 C&I EWR programs are incorporated directly into the SAE model. The small C&I  
2 sales forecast begins with a standard end-use model with saturation projections and  
3 average electricity usage per end-use derived from the EIA's AEO 2023 for the  
4 East North Central region in which DTE Electric operates. Since small C&I  
5 buildings within the DTE Electric service territory consume electricity differently,  
6 the projections are weighted by intensity and prevalence of 11 different building  
7 types as defined by the EIA. To better calibrate these projections to the Company's  
8 service area, employment values are used to weight end-use intensities with the  
9 Company's service area employment data. The combination of saturations and  
10 average electricity per end-use is indexed and calibrated to the Company's usage  
11 per customer for a base year to create an electricity forecast for each end-use.
- 12 Utilization variables, which explain how much an end-use is utilized, are combined  
13 with end-use intensities. For small C&I, the primary variables used to explain  
14 utilization are weather, gross state product, non-manufacturing employment and  
15 households. The utilization variables are then combined with the end-use intensities  
16 to compute three explanatory variables that are:
- 17 • XHeat – An aggregated heating variable that captures changes in heating end-  
18 use saturation and efficiency, and combined with HDDs, economic, and other  
19 factors that impact the utilization of heating equipment.
  - 20 • XCool – An aggregated cooling variable that captures changes in cooling end-  
21 use saturation and efficiency, and combined with CDDs, economic, and other  
22 factors that impact the utilization of cooling equipment.
  - 23 • XOther – An aggregated base-load variable that captures changes in base-  
24 load end-use saturation and efficiency, and combined with number of days in

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1 a month, economic, and other factors that impact the utilization of base-load  
2 equipment.

3  
4 Along with seasonal factors, the resulting explanatory variable is then regressed  
5 against the Company's small C&I monthly use per customer sales. The model  
6 effectively acts as the statistical adjustment and calibrates the end-use forecast to  
7 the Company's historical sales.

8  
9 Small C&I customers are modeled using a regression with households used as the  
10 primary variable. The customer forecast is then multiplied by the use per customer  
11 from the SAE model to produce the total small C&I class sales forecast.

12

13 **Q25. How was the large C&I forecast developed?**

14 A25. The large C&I forecast begins by disaggregating all primary service sales into  
15 seven distinct super sector markets. Granular market segments defined by the  
16 customer's North American Industry Classification System (NAICS) code are  
17 aggregated into super sectors defined by the Bureau of Labor Statistics. The seven  
18 super sectors are medical and education, transportation, trade, and utility (TTU),  
19 offices, other markets, automotive, other manufacturing, and steel.

20

21 Econometric models, a commonly used technique among utility forecasters, are  
22 used to forecast sales for the Company's service territory at the super sector level.  
23 Individual regression equations are applied to all super sectors, using various  
24 explanatory variables such as corresponding super sector employment and gross  
25 state product, automotive production, weather, and cumulative EWR savings, to

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1 drive the forecast. The regression results are evaluated for reasonableness and  
2 validated through various model statistics.

3  
4 Regression modeling alone does not account for incremental growth of  
5 technologies such as electric vehicles. Unlike residential and small C&I, large C&I  
6 is not modeled by end-use. Therefore, it is necessary to make post-regression  
7 adjustments to the forecast to incorporate future technology and customer specific  
8 closings or expansions. The two main post regression adjustments include EV  
9 growth and large customer projects that are informed by customer account  
10 managers.

11

12 **Q26. Is the method to forecast customer class sales the same as what the Company**  
13 **proposed in Case No. U-21534?**

14 A26. For the most part, yes. The underlying methods used to forecast by customer class  
15 remain foundationally the same, with only changes to the input data. In general,  
16 most changes to the forecast consist of refreshing data sources to reflect the most  
17 current outlooks, or routine process updates such as updating the normal-weather  
18 period to include the most recent year of data.

19

20 **Q27. What level of EWR is assumed in the forecast?**

21 A27. The load forecast assumes EWR savings consistent with Case No. U-21322 and  
22 Case No. U-21193, the Company's most recent EWR Plan and Integrated Resource  
23 Plan filings respectively. For 2026 (the rate case test year), the Company plans to  
24 achieve 2% annual savings, made up of a 1.4% reduction in residential sales, and a  
25 2.4% reduction in C&I sales.

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1   **Q28. What type of DG resources were included in the forecast?**

2   A28. The Company, for purposes of the forecast, is defining DG as customer-sited  
3       resources that are: 1) interconnected to the distribution system on the customer's  
4       side of the utility's service meter and 2) installed to offset site load with incidental  
5       export. For forecasting purposes, the projected additional DG resources were  
6       assumed to be solar photovoltaics (PV).

7  
8   **Q29. How was the DG outlook applied to the forecast?**

9   A29. The DG outlook was developed utilizing the Company's residential and non-  
10       residential interconnection history. The forecast begins with a collection of  
11       historical and projected PV economics for both residential and non-residential  
12       customers. Variables such as, but not limited to, capital costs, operating and  
13       manufacturing costs, tax credit schedules, and electricity prices were used to  
14       determine the PV economics. These economics are used as the primary explanatory  
15       variable in a regression model, with the Company's interconnection history as the  
16       dependent variable, to project the levels of DG expected in the future.

17  
18       Two separate forecasts are produced for residential and non-residential. The  
19       historical and forecasted DG is applied directly as an additional end-use into the  
20       models for residential and small C&I.

21  
22   **Q30. What is the current market size for EVs in DTE Electric's service territory?**

23   A30. In DTE Electric's service territory of Southeast Michigan, EV sales have grown at  
24       a compound annual growth rate (CAGR) of 74% from 2019 to 2023, with  
25       approximately 17,400 EVs sold in 2023, compared to about 1,900 EVs in 2019.  
26       Year to date, 73% of the newly sold EVs in Michigan are registered in DTE



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1 Electric's service territory and 80% of these are all-electric.<sup>2</sup> There are currently  
2 almost 60,000 EVs registered in Southeast Michigan<sup>3</sup>, and the Company forecasts  
3 this number increasing to an estimated 334,000, including medium and heavy-duty  
4 vehicles, by 2029.

5

6 **Q31. How did the Company forecast the EV registrations?**

7 A31. This EV registration forecast was derived from a combination of a linear trend  
8 forecast developed using recent registration data from S&P Global and a long-term  
9 forecast derived from forecasts published by external industry experts<sup>4</sup>.

10

11 For the linear trend forecast, EV registrations were projected using a trend of EV  
12 registrations in DTE Electric service territory from 2020 through 2023. For the  
13 industry expert forecast, several different projections for new vehicles were  
14 averaged together to obtain a forecast for the state of Michigan. The Michigan EV  
15 forecast is then converted to a DTE Electric EV forecast by applying a factor  
16 representing the percentage of new EVs registered in the DTE Electric service  
17 territory compared to the total registered in the state.

18

19 The final forecast takes both the linear trend and the industry expert projections into  
20 consideration through the application of a weighted average. In the near term, more  
21 weight is applied to the linear trend, while in the longer term more weight is applied  
22 towards the industry expert forecast.

---

<sup>2</sup> The balance are plug-in hybrid EVs; regenerative hybrids and hydrogen fuel cell vehicles are not considered EVs.

<sup>3</sup> As of September 30<sup>th</sup>, 2024.

<sup>4</sup> Including Bloomberg New Energy Finance, The Electric Power and Research Institute, and the U.S. Energy Information Administration

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1   **Q32.   How was the EV outlook applied to the forecast?**

2   A32.   For the EV forecast, the cumulative vehicle stock forecast was used as a starting  
3           point to estimate the historical and forecasted load in the Company's service  
4           territory.

5  
6           The EV stock is multiplied by a kWh/vehicle value and the assumed vehicle miles  
7           traveled unique to each vehicle segment to arrive at the load associated with the  
8           forecasted vehicle volumes. Vehicle segments modeled include battery-electric  
9           light-duty vehicles, plug-in hybrid light-duty vehicles, buses, medium-duty trucks,  
10          and heavy-duty trucks.

11  
12          For light-duty vehicles, the Company's appliance saturation survey suggests  
13          approximately 75% of EV charging is done at personal residences while the other  
14          25% is done at non-residential locations, such as workplace or public charging  
15          stations. Therefore, approximately 75% of the light-duty EV sales forecast was  
16          applied to the residential model as an additional end-use while the remaining was  
17          applied to the small and large C&I models as a starting point to the forecast. Over  
18          time, as EV adoption becomes more mainstream, the forecast assumes these  
19          dynamics will shift in favor of more non-residential charging. As public  
20          infrastructure is built out to support direct current (DC) fast charging and  
21          consumers without access to home charging begin to adopt EVs, the boundary  
22          between home and public charging is projected to overlap.

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1 For fleet (medium-duty and heavy-duty) vehicles, 100% of the fleet EV sales  
2 forecast was applied to the large C&I model as an incremental adjustment to the  
3 forecast.

4

5 **Q33. How was the Electric Choice sales forecast developed?**

6 A33. The Electric Choice sales forecast was based on 10% of retail sales. Historical class  
7 ratios are applied to the Electric Choice cap and new customer load from the last  
8 historical year is added separately.

9

10 **Q34. How was the DTE Electric system peak demand forecast developed?**

11 A34. A bottom-up hourly load model was used to forecast annual DTE Electric service  
12 area and DTE Electric bundled peak demand. This model was also utilized to  
13 determine monthly peak demands in the forecast period.

14

15 **Q35. What is a bottom-up hourly load model?**

16 A35. A bottom-up approach, put simply, obtains the peak demand forecast by summing  
17 hourly values from all the different end-uses. Load profiles are developed for each  
18 of the sales classes utilizing the Company's historical hourly AMI data. Residential  
19 and small C&I classes were further broken into base, cooling, and heating end-uses  
20 which captures changing peak demand levels based on the composition of the  
21 underlying load shapes, and changes in end-use consumption. Additional load  
22 profiles for technologies such as EVs and DG are also used.

23

24 The profiles are scaled to the monthly energy forecasts by customer class, adjusted  
25 for losses, and summed to predict the system total. The highest hourly value in a

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1 year or month is the peak forecast. Modeling system peak using a bottom-up  
2 approach is advantageous in that it captures load shape diversity. For example, as  
3 customers adopt more efficient HVAC units, or technologies such as EVs increase  
4 in penetration, a bottom-up approach provides the ability to understand changes in  
5 the system peak, as well as the hour in which it occurs.

6

7 **Q36. What temperature assumptions were made regarding the peak demand**  
8 **forecast?**

9 A36. Normal temperature on the day of the annual peak is assumed to be 82.3 F, which  
10 is the mean temperature at Detroit Metropolitan Airport. This value is based upon  
11 an average peak-day mean temperature for a 15-year period (2009 through 2023).  
12 The mean temperature is calculated as the average of 24-hourly temperatures for  
13 the day. The peak day is assumed to occur on a weekday in July.

14

15 **Q37. Are Demand Response programs included in the Company's peak forecast?**

16 A37. No. Demand Response programs are not included in the peak forecast. Demand  
17 Response programs, such as Interruptible Space-Conditioning, are used to meet the  
18 Company's Midcontinent Independent System Operator (MISO) resource  
19 adequacy requirements. Demand Response programs are accounted for on the  
20 supply side as load modifying resources.

21

22 **Q38. Are there any new data center loads included in the forecast?**

23 A38. No. At the time that the forecast was created, there were no agreements (binding or  
24 non-binding) for new data center load in the test year.

Line  
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1   **Q39. Have there been any data center opportunities announced since the forecast**  
2       **was created?**

3   A39. Yes, the Company has signed non-binding term sheets with three parties, one of  
4       them with Switch (a leading data center developer/operator), another with  
5       University of Michigan, and one with an undisclosed third party. At this time, there  
6       are no definite agreements, therefore the timing of any energy sales impacts is  
7       unknown.

8

9   **Q40. What is your opinion of the risk of the forecast being too low due to the data**  
10       **center projects not being included?**

11   A40. The risk is expected to be minimal in the test year. The Company does not include  
12       speculative new projects in our forecasts where there is not a binding agreement in  
13       place because the likelihood of the project getting delayed or not happening at all  
14       is too great. This is similar to not including speculative subtractions to the sales  
15       forecast due to rumored auto plant or other facility shutdowns.

16

17   **Q41. Are there risks that the forecast is too high?**

18   A41. Yes. The 2025 tariffs, enacted April 2025 have not been included in the forecast.  
19       The Company expects that the impact to North American production and the auto  
20       manufacturing plants in the DTE Electric Service Area could be significant in the  
21       near term from these tariffs. Similarly, none of the effects from any retaliatory  
22       tariffs nor steel and aluminum tariffs impacting Southeast Michigan manufacturing  
23       have been included. Although significant uncertainty exists, the forecast assumes  
24       that these tariffs will be short lived and local auto production will remain at levels  
25       similar to 2024. If the tariffs and retaliatory tariffs were to persist through the test

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1 year (2026), then supplier manufacturing would be impacted as well. In addition,  
2 Southeast Michigan would experience employment losses which would then affect  
3 the small C&I and residential forecasts.  
4

5 **Q42. Do you have an estimate of the impact of tariffs on the load forecast?**

6 A42. At a high level, based on conversations with industry experts, the Company  
7 considers the case where the tariffs impact the test year forecast to have a low  
8 probability of occurring. (approx. 20%).<sup>5</sup> Given the presence of nine auto assembly  
9 plants in our service area, the probability of at least one plant idling or shutting  
10 down during the test year is high if the tariffs continue. This could result in a direct  
11 load loss of approximately 170 GWh in the large C&I class. There is a multiplier  
12 effect as the shutdown spreads through the economy that we must consider. This  
13 we estimate at 8 to 9 times the initial impact, bringing the total impact to approx.  
14 1,500 GWh. The resulting impact to each class, assuming it would hit the supply  
15 base first and trickle down to the small C&I and residential markets, would be: 700  
16 GWh reduction to large C&I, 700 GWh reduction to small C&I, and 100 GWh  
17 reduction to residential.

---

<sup>5</sup> Tariffs on Auto Industry: Extended Disruption Now More Likely available at  
<https://www.spglobal.com/automotive-insights/en/rapid-impact-analysis/tariffs-on-auto-industry-extended-disruption-likely#link3> accessed on 03/17/2025

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1 **Part III: Historical and Current Electric Forecast Sales and Demand**

2 **Part III: Section 1: Electric Sales**

3 **Q43. When referring to 2024 in this testimony, how many months of actuals are**  
4 **included?**

5 A43. The reference to 2024 in this testimony includes twelve months of actual sales and  
6 customer counts.

7  
8 **Q44. What has been the compound annual growth rate of DTE Electric sales over**  
9 **the last five years?**

10 A44. As shown in Exhibit A-5, Schedule E1, page 4 of 4, weather normalized service  
11 area sales from 2019 to 2023 have declined during the five-year historical period.  
12 In 2019, total service area sales were 46,671 GWh and 2023 sales were 44,642  
13 GWh, representing a compound annual growth rate (CAGR) of -1.1%.

14  
15 Bundled sales have decreased from 42,115 GWh in 2019 to 40,245 GWh in 2023,  
16 representing a CAGR of -1.1%. The electric choice sales declined from 4,556 GWh  
17 in 2019 to 4,396 GWh in 2023, a CAGR of -0.9%. Refer to Exhibit A-5, pages 1  
18 through 3 for additional detail regarding historical actual sales for the service area,  
19 bundled, and electric choice.

20

21 **Q45. What are sales for the projected test period, January 2026 through December**  
22 **2026?**

23 A45. The service area sales for the projected test period, January 2026 through December  
24 2026 are 44,333 GWh and bundled sales are 39,879 GWh. The projected test period  
25 service area, bundled, and choice sales are displayed in Exhibit A-15, Schedule E1,

Line  
No.

1 pages 1, 2, and 3 on line 3. The projected known and measurable changes for  
2 bundled sales from 2022 to the projected test year are detailed in Exhibit A-15,  
3 Schedule E3.

4

5 **Q46. What is the CAGR of the DTE Electric service area electric sales from 2023**  
6 **through the forecast period to 2029?**

7 A46. The service area sales are expected to increase to 44,620 GWh in 2029. This  
8 represents a flat 0.0% CAGR. Historical 2024 sales and system output as well as  
9 the forecast of annual sales and system output for DTE Electric's service area for  
10 the years 2025 through 2029 are reflected on Exhibit A-15, Schedule E1, page 1 of  
11 3.

12

13 **Q47. What is the CAGR of DTE Electric bundled electric sales from 2023 through**  
14 **the forecast period to 2029?**

15 A47. The bundled sales are projected to decrease over the forecast period, consistent with  
16 the declining trend seen in the historical data. The bundled sales are expected to  
17 decline to 40,164 GWh in 2029. This represents a flat 0.0% CAGR. Historical  
18 bundled 2024 sales and system output as well as the forecast of annual sales and  
19 system output are shown on Exhibit A-15, Schedule E1, page 2 of 3.

20

21 **Q48. What is the CAGR of Electric Choice sales from 2023 through the forecast**  
22 **period to 2029?**

23 A48. Electric Choice sales are expected to increase to 4,456 GWh in 2029. This  
24 represents a 0.2% CAGR. Historical choice 2024 sales and the forecast of annual  
25 sales are shown on Exhibit A-15, Schedule E1, page 3 of 3.



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1   **Q49.   What is the outlook for residential class sales?**

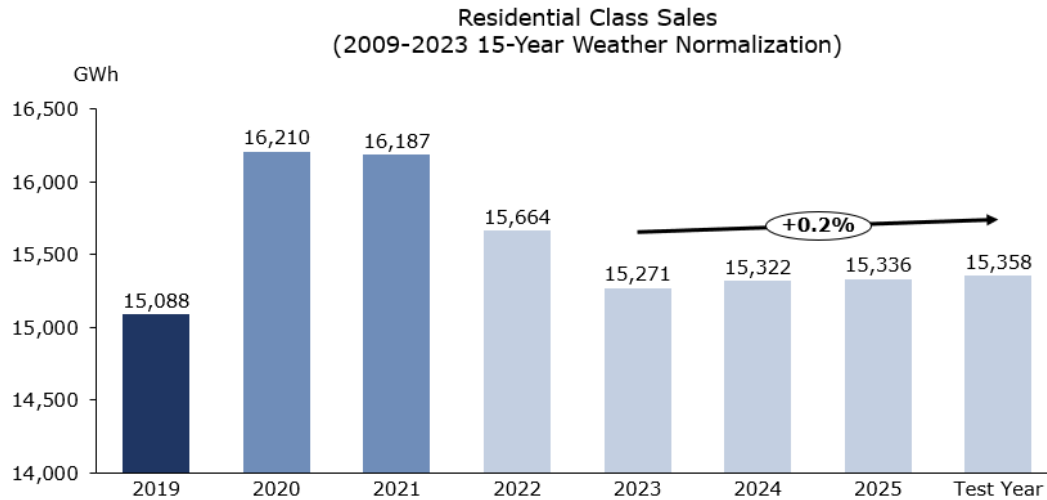
2   A49.   DTE Electric's service area residential Class sales are forecast to increase 0.2%  
3           annually, on average, between 2023 and the 2026 projected test period in the instant  
4           case. As seen in Figure 4, residential sales experienced a sharp increase in sales  
5           from 2019 to 2020 as a result of work from home policies implemented due to the  
6           COVID-19 pandemic. Residential sales continued to remain elevated through 2021  
7           and then decreased through 2022 and 2023 as workers transitioned back to in-  
8           person work. From 2021 through 2024 residential sales have declined at a -1.8%  
9           CAGR. As hybrid work arrangements have stabilized<sup>6</sup>, trends in residential sales  
10          are expected to reverse as declines in residential usage begin to slow due to the  
11          saturation of energy efficient lighting, combined with increased adoption of EVs.  
12          Modest average annual growth of 0.5% in residential customer count is expected  
13          from 2023 through 2029 due to a moderating housing market. Annual customer  
14          counts are shown in Exhibit A-15, Schedule E6. Use-per-customer from 2023  
15          through 2029 is expected to decrease by 0.1% annually on average. For a graphical  
16          view of the residential forecast, refer to Figure 4 below.

---

<sup>6</sup> The Future of the Office Has Arrived: It's Hybrid (gallup.com) available at  
<https://www.gallup.com/workplace/511994/future-office-arrived-hybrid.aspx>, accessed on 3/7/2025

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1

**Figure 4 : Residential Forecast**

2

3 **Q50. What is the outlook for small C&I class sales?**

4 A50. DTE Electric's service area small C&I class sales are forecast to increase 0.2%  
 5 annually, on average, between 2023 and the 2026 projected test period. Inversely  
 6 to residential, small C&I sales declined from 2019 to 2020 as a result of various  
 7 policies implemented due to the COVID-19 pandemic. From 2020-2022 sales  
 8 recovered as policies implemented on commercial business such as restrictions on  
 9 in-person events were lifted and more people returned to in-person work. Through  
 10 10 months of 2024, sales have stabilized around 2022 levels, mainly due to the  
 11 conclusion of restrictive policies from COVID-19 in June of 2021, combined with  
 12 less fluctuation in hybrid work arrangements. Modest average annual growth of  
 13 0.4% in Small C&I customer count is expected from 2023 through 2029 due to  
 14 modest residential customer growth. Use-per-customer from 2023 through 2029 is  
 15 expected to decrease by -0.1% annually on average. Growth in the Small C&I class  
 16 is constrained by the increase in energy efficiency programs targeting Commercial

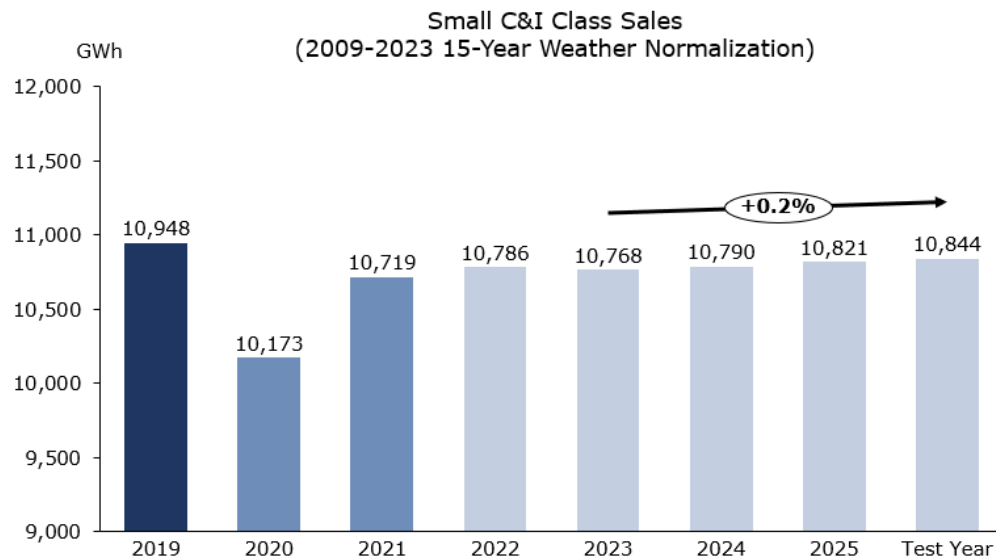
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1 and Industrial customers bundled with limited economic growth in the near term.  
2 For a graphical view of the small C&I forecast, refer to Figure 5 below.

3

4

**Figure 5 : Small C&I Forecast**



5

6 **Q51. What is the outlook for large C&I class sales?**

7 A51. DTE Electric's service area large C&I class sales are expected to decrease by 0.8%  
8 annually, on average, from 2023 to the projected test period in this instant case. As  
9 mentioned previously, large C&I class sales are allocated between seven super  
10 sector markets: education and health, trade, transportation, and utilities (TTU),  
11 offices, other markets, automotive, steel and other manufacturing. The decrease in  
12 sales is primarily due to projected declines in TTU and manufacturing employment  
13 from 2023 to 2026 affecting the largest super sectors in large C&I. The declines in  
14 the employment values are due to slowing demand and inventory levels caught up  
15 from supply chain issues over the past three years. Furthermore, increased energy  
16 efficiency initiatives targeting C&I customers offsets growth from positive

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1 employment projections in the smaller super sectors; education & health, offices,  
2 and other markets. Table 1 shows the 2023-2026 CAGRs for the employment  
3 drivers included in Exhibit A-15, Schedule E4, used in each super sectors'  
4 regression model.

5

6

**Table 1 Large C&I Employment CAGRs**

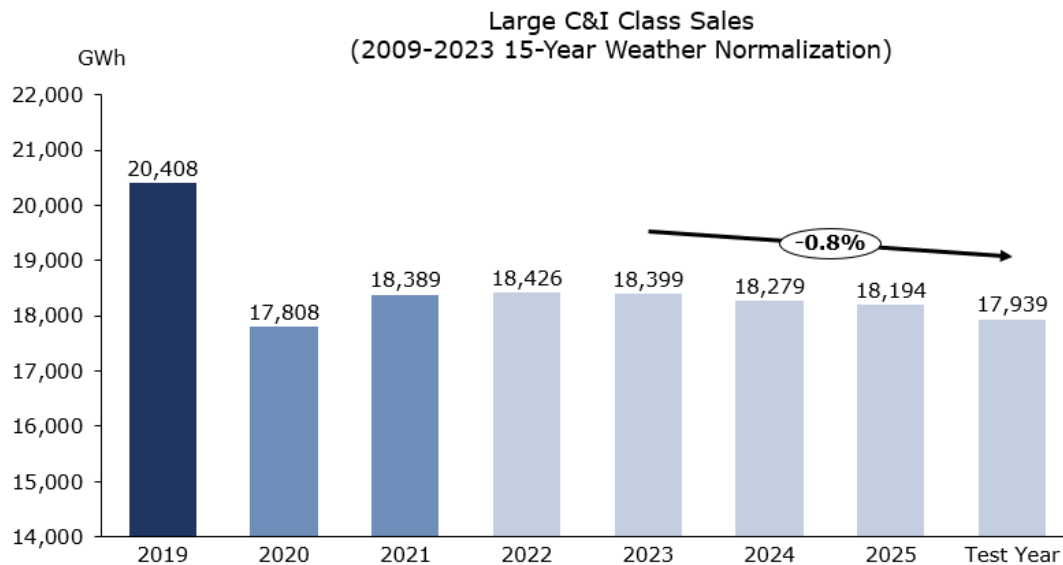
| <u>Economic Index</u>            | <u>2023-2026 CAGR</u> |
|----------------------------------|-----------------------|
| Education & Health<br>Employment | 1.9%                  |
| TTU Employment                   | -0.5%                 |
| Office Employment                | 0.6%                  |
| Other Markets Employment         | 0.7%                  |
| Manufacturing Employment         | -2.7%                 |

7

8 For a graphical view of the large C&I forecast, refer to Figure 6 below. The CAGR  
9 for 2023 to the 2026 projected test period is -0.8%.

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1

**Figure 6 : Large C&I Forecast**

2

3 **Q52. What is the outlook for other class sales?**

4 A52. DTE Electric's service area other Class sales are expected to decrease 1.0%  
 5 annually, on average, from 2023 through 2029. The other Class consists of street  
 6 lighting and traffic signals. The main reason for the decline in sales is the use of  
 7 more energy efficient lighting. For further detail on street lighting see the testimony  
 8 of Company Witness Hartley.

9

10 Part III, Section 2: Electric Peak Demand

11 **Q53. What has been the CAGR of DTE Electric peak demand for the historical**  
 12 **period 2019-2023?**

13 A53. As shown in Exhibit A-5, Schedule E1, page 4 of 4, the service area peak demand  
 14 in 2019 was 11,145 MW and 2023 peak demand was 10,853 MW, representing a  
 15 CAGR of -0.7%. The bundled peak demand was 10,355 MW in 2019 and 10,086  
 16 MW in 2023 at a CAGR of -0.7%.

Line  
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1   **Q54. What are the system output and annual peak demand for the projected test**  
2       **period, January 2026 through December 2026?**

3   A54. The service area system output and annual peak demand for the projected test  
4       period, January 2026 through December 2026 are 47,503 GWh and 10,706 MW,  
5       respectively. The projected test period bundled system output and annual peak  
6       demand are 42,824 GWh and 9,962 MW, respectively. The service area and  
7       bundled system outputs and peak demand can be found on Exhibit A-15, Schedule  
8       E2, pages 1 and 2, line 8. The Electric Choice impact is displayed in Exhibit A-15,  
9       Schedule E2, page 2 of 2. Low (10%) and high (90%) confidence bands on  
10      forecasted summer peak demand are provided for DTE Electric's service area and  
11      DTE Electric's bundled sales levels and can be found on Exhibit A-15, Schedule  
12      E2, pages 1 and 2.

13

14   **Q55. What is the CAGR of the DTE Electric service area system peak demand from**  
15       **2023 over the forecast period to 2029?**

16   A55. As shown in Exhibit A-15, Schedule E2, page 1 of 2, DTE Electric's weather  
17       normalized service area peak demand declines from 10,853 MW in 2023 to 10,592  
18       MW in 2029, representing a CAGR of -0.4%. The decline in peak demand is  
19       mainly due to a decline in residential air-conditioning electricity sales, which is  
20       projected to decline 0.6% on average annually, due to increased efficiency.

Line  
No.

1 **Q56. What is the CAGR of the DTE Electric bundled peak demand from 2023 over**  
2 **the forecast period to 2029?**

3 A56. DTE Electric's bundled peak demand forecast declines from 10,086 MW in 2023  
4 to 9,853 MW in 2029, representing a CAGR of -0.4%. The bundled peak demand  
5 forecast from 2024 to 2029 is shown in Exhibit A-15, Schedule E2, page 2 of 2.

6

7 **Part IV: Electric Load Forecast Accuracy**

8 **Q57. How are DTE Electric's sales forecast and methodologies validated?**

9 A57. DTE Electric's service area sales forecast is tracked annually, and the Company  
10 continuously checks the accuracy of the sales forecast models. For example, as  
11 shown in Exhibit A-15, Schedule E5, page 1, the DTE Electric total service area  
12 forecast in 2023 was 44,389 GWh (line 13). Total weather-normalized service area  
13 sales (adjusted for normal weather assumed in that year) in 2023 were 44,713 GWh  
14 (line 6). This represents a 99.3% accuracy for the 2023 total sales forecast. On  
15 average, for historical years 2019 through 2023, the absolute percent variance for  
16 the total sales forecast is 1.89% using the Company's forecasting methods, as  
17 shown in Exhibit A-15, Schedule E5, page 1.

18

19 **Q58. Which Company forecast was used for the accuracy measures used in Exhibit**  
20 **A15, Schedule E5? Why?**

21 A58. The Company uses the last forecast produced in a given calendar year as the basis  
22 for the accuracy measurement shown in Exhibit A-15, Schedule E5. For example,  
23 the Company typically produces a forecast in Q4 of any given calendar year for the  
24 next calendar year sales. This forecast was chosen as the basis for accuracy to most

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1 closely resemble the forecasts submitted by peer utilities in the ITRON  
2 Benchmarking analysis discussed later in my testimony.

3

4 **Q59. Can you explain the deviation in accuracy experienced in 2020 and 2021, as**  
5 **shown in Exhibit A-15, Schedule E5, page 1?**

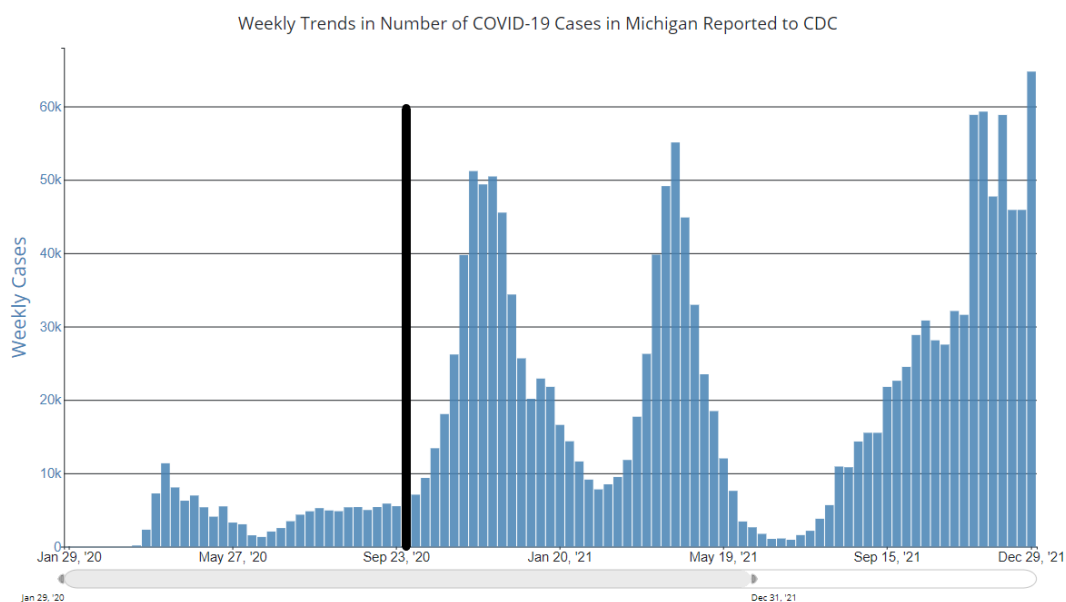
6 A59. The forecast for 2020 was completed in 2019, before the COVID-19 pandemic  
7 began to impact the United States. In March 2020, the spread of COVID-19 caused  
8 a shift in electricity consumption throughout DTE Electric's service territory.  
9 Commercial and industrial sales fell due to business closures from government  
10 mandates while residential sales increased as a result of work from home policies  
11 enacted to mitigate the spread of COVID-19. As seen in Figure 7, mid-way through  
12 2020, case counts of COVID-19 began to stabilize which led to business activity  
13 attempting to gradually resume pre-pandemic operations. While still uncertain, it  
14 appeared that the effects of COVID-19 likely began to subside through the rest of  
15 2020 and into 2021. The forecast for 2021 was completed in the third quarter of  
16 2020, marked in black in Figure 7, just prior to the rise in cases caused by the  
17 emergence of the Delta variant. The sharp spike in cases experienced in the fourth  
18 quarter of 2020, as well as the subsequent waves experienced in 2021 caused more  
19 business closures, as well as continued work from home policies, ultimately  
20 creating sustained sales variances through 2021. This was contrary to what the  
21 trends in the data suggested at the time that the 2021 forecast was completed.



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1

**Figure 7 : Michigan COVID-19 Case Counts 2020 & 2021**



2

3 **Q60. How has the Company's forecast accuracy performed in the periods following**  
4 **the COVID-19 pandemic?**

5 A60. As seen on Exhibit A-15, Schedule E5, page 1 of 2, Lines 19, 20 and 21 the  
6 Company achieved an absolute percent variance of 0.50% in 2022 (99.5%  
7 accurate), 0.73% in 2023 (99.27% accurate) and 0.9% in 2024 (99.1% accurate).  
8 The Company's average absolute percent variance for 2022 through 2024 is 0.71%,  
9 representing 99.29% accuracy shown on Exhibit A-15, Schedule E5, page 1 of 2,  
10 line 23.

11

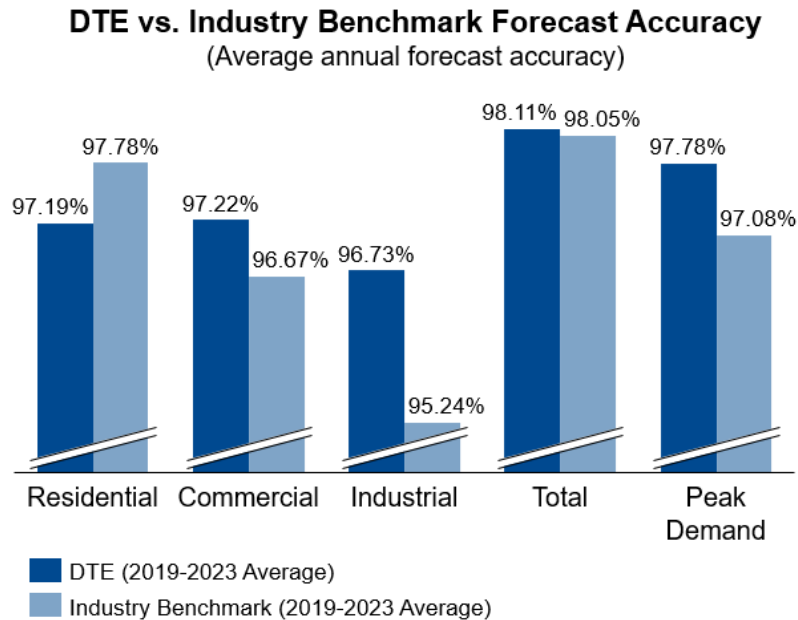
12 **Q61. Does the Company perform any benchmarking on forecast accuracy?**

13 A61. Yes. The Company conducts benchmarking activity by researching forecast  
14 accuracy studies. A study, conducted by ITRON in 2024 is shown in Exhibit A-  
15 15, Schedule E5, page 2. DTE Electric is on par with peer utilities across the nation  
16 in forecasting by customer class and peak demand, as shown in Figure 8 below.

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1

**Figure 8 : DTE Electric vs. ITRON Forecast Accuracy Benchmark**



2

**Part V: Demand Response Overview**

**Q62. What is the purpose of DR?**

A62. DR is designed to reduce or shift enrolled customers' energy usage during periods of high demand and/or price to ensure continued reliability and/or reduce power supply costs. DR programs provide special rates or other forms of compensation to incentivize desired customer usage behaviors.

9

**Q63. What are the benefits to customers for participating in DR programs?**

A63. DR programs allow electric customers to play a role in the reliable 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,

15

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1 less efficient or more expensive forms of generation are not needed if DR is a more  
2 cost-effective alternative.

3

4 **Q64. What are the benefits of DR to the utility?**

5 A64. The reduction or shift in customer usage from DR programs can provide value to  
6 the utility by reducing the need for additional generation, resulting in lower energy  
7 costs and supporting the Company's generation transformation. If DR programs are  
8 less costly than other capacity resources, the utility and all customers can benefit  
9 from displacing or deferring the need for new generation resources. In addition,  
10 reducing electricity usage when demand is the highest can result in lower wholesale  
11 energy prices.

12

13 **Part VI: DR Regulatory Framework**

14 **Q65. What is the regulatory framework adopted by the Commission to approve,**  
15 **recover, and reconcile expenditures in the Company's DR portfolio?**

16 A65. In the September 15, 2017, Order in Case No. U-18369, the Commission approved  
17 a 'three-phase' approach for the approval, recovery, and reconciliation of DR  
18 expenditures. In the first phase, DR proposals are evaluated in the context of an  
19 integrated resource plan (IRP). In the second phase, DR plans that were approved  
20 as part of the IRP are considered pre-approved and the associated capital costs are  
21 included in rates in the utility's future general rate cases. The utility can also  
22 propose changes or modifications to DR programs or pilots in general rate cases.  
23 The IRP DR proposed programs and pilots, as well as any changes, are then  
24 evaluated and approved in rate cases and can be considered for inclusion in the next  
25 IRP. The third phase involves a reconciliation of DR costs, participation rates, and

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1 demand reduction achieved on an annual basis. The Commission also stated that  
2 during the reconciliation proceedings, actual capital spending in the examination  
3 period will be reconciled against the amount preapproved in the IRP and recovered  
4 in a rate case while Operation and Maintenance (“O&M”) spending will be  
5 reconciled against the amount approved and recovered in a general rate case.

6

7 In addition, the Company can earn a financial incentive through a financial  
8 incentive mechanism (FIM) calculated in each annual reconciliation case. The FIM  
9 methodology was agreed upon in the approved settlement of the 2019 DR  
10 Reconciliation (February 18, 2021, Order in Case No. U-20793).

11

12 **Q66. Does the Company still support the current three-phase framework that was**  
13 **established in Case No. U-18369?**

14 A66. No. The Company believes that the three-phase approach is no longer necessary,  
15 similar to the comments filed by Staff in Case No. U-21637. The separate  
16 reconciliation process causes unnecessary confusion with the overlapping of  
17 electric rate cases and reconciliation cases due to the timing of the filings and orders  
18 received.

19

20 **Q67. Does the Company have any suggestions on how to improve the regulatory**  
21 **framework of DR?**

22 A67. Yes, the Company suggests removing DR from rate cases entirely and  
23 implementing a DR plan filing that would include a surcharge, similar to Energy  
24 Waste Reduction (EWR). A DR reconciliation would then be filed annually to  
25 adjust the surcharge as appropriate.

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1 **Q68. Is the Company proposing a change to the regulatory framework in this filing?**

2 A68. No, the Company is not proposing a regulatory change in this filing for DR.

3 However, the Company is interested in working with MPSC Staff and other

4 stakeholders to develop a regulatory framework that works for all parties if the

5 Commission agrees a collaborative would be appropriate.

6

7 **Part VII. DR Portfolio**

8 **Q69. Could you describe the Company's current DR portfolio?**

9 A69. Yes. DTE Electric develops and manages its DR portfolio offering customers a

10 range of options consisting of programs, customer incentives, tariff structures, and

11 education. These programs are based off customer profiles and willingness to

12 curtail or shift energy usage during peak hours. As part of the development process,

13 the DR organization evaluates customer behavior, program acceptance and

14 validates technologies that can deliver benefits to its customers.

15

16 The Company's current DR portfolio is made up of tariffs, programs, and pilots

17 that are available to residential, commercial and industrial customers. The goal of

18 the Company's DR portfolio is to deliver cost-effective, measurable peak demand

19 reduction by effectively engaging customers to reduce or shift their energy

20 consumption.

21

22 **Q70. What measurable value does the DR portfolio provide?**

23 A70. The Company currently registers all its DR programs and tariffs as LMRs with

24 MISO and receives capacity credit.

Line  
No.

1 **Q71. What programs and tariffs are included in the Company's current DR**  
2 **portfolio?**

3 A71. The Company's DR portfolio is made up of CoolCurrents™, Smart Savers,  
4 Interruptible Water Heating, and multiple interruptible tariff rates for Commercial  
5 and Industrial (C&I) customers. The participants in the DR programs or on the  
6 tariffs receive a discounted rate or incentive in exchange for reducing their load  
7 during DR events.

8

9 **Q72. Is the Company making any changes to the DR portfolio and why is the**  
10 **Company making the change?**

11 A72. Yes. The decision was made to sunset the SmartCurrents program in 2025 and focus  
12 on a single thermostat offering, the Smart Savers program. This is due to the  
13 confusion of having two thermostat programs and the low cost-effectiveness score  
14 of the SmartCurrents program when compared to other programs. In addition, the  
15 enrollment in SmartCurrents remains well below the level of Smart Savers.

16

17 **Q73. What is a DR event?**

18 A73. A DR Event is a period when DR resources are activated to reduce demand and  
19 maintain grid reliability.

20

21 **Q74. How do the programs and tariffs that make up the Company's DR portfolio**  
22 **fit into the current MISO construct?**

23 A74. The MWs associated with the programs and tariffs are registered as Load  
24 Modifying Resources (LMR) to meet the company's resource adequacy  
25 requirements (or capacity obligation) one or more seasons.

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1 The Company's interruptible tariffs (D3.3, D8, R1.1, R1.2, R10) are registered as  
2 year-round resources and provide MWs in each season. CoolCurrents and Smart  
3 Savers are registered for the Spring, Summer and Fall seasons while R12 is only  
4 available for the Summer season. The Company registers CoolCurrents with a one-  
5 hour notification time, meaning MISO can instruct the Company to begin cycling  
6 participating customers' air-conditioning units within one-hour of receiving the  
7 instructions from MISO. All the Company's other resources are registered with a  
8 two-hour notification time meaning these resources must respond to the MISO  
9 instruction within two-hours.

10

11 In the current MISO construct, the Company's LMRs are only dispatched by MISO  
12 during system integrity events or better known as during MISO Max Gen  
13 Emergency Step 2A. CoolCurrents, Smart Savers, Interruptible Water Heating and  
14 D3.3 can be dispatched by the Company for other reasons such as economics or  
15 localized relief in addition to MISO ordered dispatches.

16

17 **Q75. How does the Company forecast the DR MWs used to meet resource**  
18 **adequacy?**

19 A75. Beginning with the 2024/25 MISO Planning Year, the Company changed how it  
20 calculates DR MWs in its portfolio to standardize the process and assure that the  
21 Company resources can perform to the expected value reliably when called upon.  
22 To forecast the available DR load for the interruptible tariffs, the Company uses  
23 previous year's actual interruptible load at the MISO Seasonal Coincident Peak  
24 while also considering any known customer changes. For DR programs like Smart  
25 Savers and CoolCurrents, the Company uses actual performance data from test

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1 events and a regression model to calculate event performance over a four-hour  
2 event. The lowest load reduction observed during the four-hour period is then used  
3 to calculate the MWs that are claimed in the PRA to assure the Company isn't  
4 overstating the interruptible capabilities and keeps reliability at the forefront of  
5 demand response.

6

7 **Q76. Why does the Company use these methodologies to calculate the amount of**  
8 **MWs within the DR portfolio?**

9 A76. One of the requirements set forth by MISO, is that the load reduction from DR must  
10 be sustainable for four hours. By using actual data that already includes customer  
11 overrides and opt outs, the Company can assure its DR resources can reliably  
12 perform for four hours as required by MISO.

13

14 **Q77. Do other MISO participants use a similar methodology to calculate DR**  
15 **values?**

16 A77. The Company cannot speak to how all other MISO participants calculate DR MW  
17 values, as there is no standard within MISO on how to calculate MWs. However,  
18 the Company is aware that some utilities simply reduce their peak DR value by an  
19 arbitrary percent while others just use the peak reduction achieved during a  
20 previous event. Both of these methodologies can potentially overstate the available  
21 DR MWs which in turn, could put reliability at risk.



Line  
No.

1   **Q78. Has this change in methodology affected the amount of MWs the Company**  
2       **claims to meet resource adequacy requirements?**

3   A78. Yes, the change in methodology has decreased the size of the Company's portfolio  
4       from previous years.

5

6   **Part VIII. Evolving DR Landscape**

7   **Q79. What is the history of DR aggregation in the State of Michigan?**

8   A79. In the order in Case No. U-16020 dated September 29, 2000, DR aggregation in  
9       Michigan was banned, meaning only Load Serving Entities (LSEs) could offer DR  
10      programs to customers. This ban on DR aggregation remained in effect until August  
11      8, 2019. In the order in Case No. U-20348, the ban on DR aggregation was lifted  
12      for Alternative Energy Suppliers (AESs) but remained in effect for bundled  
13      customers. On June 23, 2022, in Case No. U-21099, the Commission requested  
14      comments to eight questions on DR, including one surrounding lifting the ban on  
15      DR aggregation. On December 21, 2022, the Commission lifted the ban on DR  
16      aggregation for customers with a minimum size of 1 MW of enrolled load while  
17      also filing its intention to work with stakeholders to develop customer protections  
18      for resources smaller than 1 MW, which would include residential customers. The  
19      Commission stated that the ban on resources smaller than 1 MW may be revisited  
20      in the future. To date, the ban on resources smaller than 1 MW has remained in  
21      effect. When MISO implements FERC 2222, a state's right to opt-out of DR  
22      aggregation would be limited, which could potentially open DR aggregation for all  
23      bundled load in Michigan.

Line  
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1   **Q80. Does the Company have concerns with the Commission lifting the ban on DR**  
2       **aggregation on resource adequacy?**

3   A80. Yes. The Company has concerns of the effect that lifting the ban would have on  
4       system reliability as the Company is the supplier of last resort. Without  
5       transparency into the operations of aggregators, it is nearly impossible for the  
6       Company to know the exact availability of DR on the system and when it is used  
7       which could have an impact on the ability for the Company to accurately forecast  
8       peak load. In addition, it is difficult to determine if DR enrollments by aggregators  
9       are legitimate and can be reliably used when called upon. These concerns have  
10      already been legitimized by recent news articles highlighting instances of DR fraud  
11      within MISO by companies such as Ketchup Caddy. There have also been cases  
12      where aggregators have been accused of signing up residential customers without  
13      their knowledge and consent as seen in the recent settlement agreement between  
14      MISO and Voltus. In addition, the Company is concerned that lifting the ban  
15      entirely could cause confusion for residential customers. Customer confusion could  
16      result in double counting if customers enroll in DR programs with more than one  
17      provider as well as customers not fully understanding who to contact when an issue  
18      arises.

19  
20      As expressed in Case No. U-21099, third-party aggregation could exacerbate  
21      resource adequacy concerns and create other complexities including double  
22      counting and data security concerns. Ultimately, the Company is responsible for  
23      maintaining reliability for its customers and unlike aggregators, does not profit  
24      from DR.

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1 The Company continues to design and implement a cost-effective and diverse  
2 portfolio that provides value to the utility, its customers and works to maintain  
3 system reliability. By having a cost-effective and diverse portfolio, customers will  
4 not need to contract with an aggregator for their DR programs and instead can  
5 remain a valuable resource that benefits all utility customers.

6

7 **Q81. Has the Company attempted to partner with aggregators on DR offerings?**

8 A81. Yes. In the settlement of the Company's 2022 IRP, DTE Electric agreed to procure  
9 DR-related MISO Zonal Resource Credits (ZRCs) through a competitive bidding  
10 process. Specifically, the Company agreed to issue two 25 MW solicitations, one  
11 for the 2025/26 Planning Year (PY) and one for the 2026/2027 PY, as well as a 100  
12 MW solicitation for the 2027/28 PY.

13

14 **Q82. What was the result of the first solicitation for 25 MWs?**

15 A82. The Company worked with Guidehouse to develop the Request for Proposal (RFP)  
16 and issued the first request on June 26, 2024. The Company only received one intent  
17 to bid response and received zero bids from the 14 aggregators invited to bid.

18

19 **Q83. Why does the Company believe there were no responses to the RFP?**

20 A83. The RFP was written to assure accountability from the aggregators, so that the  
21 Company can ensure reliability and comply with the MISO tariff. In an attempt to  
22 improve the RFP for the second solicitation for the 2026/27 MISO Plan Year, the  
23 Company contacted the bidders to gather feedback either through written responses  
24 or interviews. Despite the Company's efforts, no aggregators responded to the  
25 Company's request for dialogue despite multiple attempts. Given the Company has

Line  
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1 not received feedback from the aggregators we can only speculate as to the reasons  
2 behind the lack of response.

3

4 **Q84. What changes are MISO exploring related to LMRs?**

5 A84. MISO is exploring accrediting LMRs based on actual historic availability. In  
6 addition, MISO is proposing four different tariff changes including dividing LMRs  
7 into Type I and Type II, additional testing requirements, changing how LMRs are  
8 accredited and modifying the number of interruptions per season. These proposals  
9 are discussed by Company Witness Burgdorf.

10

11 **Q85. If implemented, how might these MISO changes affect the DR portfolio?**

12 A85. The proposed MISO changes will likely lead to customer attrition, though it is  
13 difficult to calculate how much, which could result in a smaller DR portfolio,  
14 especially within the C&I customer class. An increase in customer attrition would  
15 be caused by the likely increase in future system integrity events, testing  
16 requirements or in-ability to fully comply with MISO dispatches. For example, a  
17 large customer may not be able to fully respond within 30 minutes to qualify as an  
18 LMR Type II but would not want to take on the risk of being dispatched during a  
19 Max Gen Warning and may no longer see the benefits of DR participation. In  
20 addition, customers have been able to opt out of testing as testing is inconvenient  
21 and costly to large customers as they would have to shut down operations to  
22 demonstrate compliance. As opting out of testing is no longer allowed by MISO,  
23 customers may wish to pass on this inconvenience and lost revenue due to lost  
24 operations and unenroll from a DR tariff. The Company continues to analyze and

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1 design new DR programs that will fit within the proposed MISO construct and will  
2 appeal to customers that want to participate in demand response.

3

4 **Q86. What is the Company doing to prepare for potential MISO changes from the**  
5 **current construct?**

6 A86. The Company understands that the proposed MISO changes, if implemented as  
7 currently written, will affect its DR portfolio and its customers taking service under  
8 interruptible rates. We will continue to keep abreast of these proposals through  
9 stakeholder meetings and will remain flexible when it comes to its DR portfolio,  
10 understanding that these changes, if filed and approved, could change the way the  
11 Company manages and designs its DR portfolio. As these proposals become better  
12 understood and possibly implemented, the Company will include in future DR  
13 filings any potential impacts to the Company's DR portfolio and its corresponding  
14 financial incentive mechanism calculation. If needed, the Company will propose  
15 any changes to tariffs and programs for the portfolio to remain cost effective,  
16 knowing that these types of changes, whether it be a calculation methodology or  
17 MISO LMR changes could affect the cost-effectiveness of programs. In addition,  
18 the Company will examine the potential to adjust current programs, where possible,  
19 to provide capacity for additional seasons beyond summer. The Company will also  
20 evaluate the likely LMR accreditation changes and determine if any program  
21 adjustments, such as number of events or event timing, would improve the capacity  
22 credit of its programs. Continued investment in DR is important as DR programs  
23 continue to be valuable resources within MISO's capacity construct. DTE  
24 continues to be an active participant in MISO stakeholder meetings and filing  
25 comments on the proposals.

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1 **Part IX: DR Portfolio Investments**

2 **Q87. How much capital is the Company forecasting to invest in the DR portfolio**  
3 **during the bridge year, January 1, 2024, through December 31, 2025, and the**  
4 **forecasted test year, January 1, 2026, through December 31, 2026?**

5 A87. As shown in Exhibit A-12 B5.6 p1, during the bridge period the Company is  
6 forecasting a capital investment of \$11.3 million during the bridge period and \$4.4  
7 million during the forecasted test period.

8

9 **Q88. How much O&M is the Company forecasting to spend in 2026 on DR?**

10 A88. The Company is forecasting to spend \$6.2 million in 2026 to support the  
11 development and execution of its DR Portfolio. This represents a \$3.8 million  
12 increase from 2023 levels. This can be seen on Line 9 of Witness Foley's Exhibit,  
13 A-13, Schedule C5.9.

14

15 **Q89. What is the CoolCurrents Program?**

16 A89. CoolCurrents is the program name for the Interruptible Space Conditioning tariff  
17 (Rate D1.1) that is available to residential and commercial customers. Customers  
18 who enroll in CoolCurrents are equipped with a direct load control device (LCD)  
19 on their air conditioning unit(s) or central heat pump that allows the Company to  
20 cycle the associated appliance in exchange for a discounted rate. The cycling of the  
21 appliance is limited to no more than eight hours in any 24-hour period and events  
22 can be called year-round in any of the four MISO seasons. Being that this is  
23 considered a direct load control (DLC), customers do not have the ability to opt-  
24 out or override events, giving the Company a reliable DR resource with predictable  
25 load reduction.

Line  
No.

1   **Q90. Can you further describe the bridge period and forecasted test year capital**  
2       **spend in the CoolCurrents Program?**

3   A90. Yes, during the bridge period, the Company is forecasting to spend \$4.2 million on  
4       the CoolCurrents Program. The bridge period spend includes LCD investigations  
5       and resets and equipment purchases for the installation of LCDs. During the bridge  
6       period, the Company is forecasting to purchase and install up to 15,000 new LCDs  
7       (including 24v and 240v devices) and continue investigations into offline devices.  
8       The installations will be done through a combination of contractors and internal  
9       field service personnel.

10

11       During the forecasted test year, the Company forecasts to spend \$3.8 million. The  
12       forecasted spend during the test year includes the purchase and installation of up to  
13       another 15,000 LCDs. The Company will continue to utilize a combination of  
14       contractors and internal field personnel to complete the installations. Program  
15       management associated with CoolCurrents is also included in the projected spend  
16       for both the bridge period and the forecasted test year.

17

18   **Q91. Could you describe the O&M spend associated with the CoolCurrents**  
19       **Program?**

20   A91. Yes. Along with installing 24v and 240v alternative devices which is a capital  
21       expense, the Company has also partnered with a contractor to fix customers' 24v  
22       lines that are no longer connected. The Company is targeting customers who  
23       already have a 24v LCD installed but no longer have the proper 24v wiring to  
24       support the device. The Company is forecasting to fix 5,000 24v lines in 2025 and

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1 2026. The Company is projecting spending \$0.8 million in O&M in 2026 to support  
2 the CoolCurrents Program.

3

4 **Q92. How many additional MWs will the capital and O&M investment on**  
5 **CoolCurrents result in?**

6 A92. The continued investment in CoolCurrents will increase the MWs associated with  
7 the CoolCurrents program by nearly 32 MWs.

8

9 **Q93. How much capital is the Company forecasting to spend on SmartCurrents?**

10 A93. During the bridge period ending December 31, 2025, the Company is projecting to  
11 spend \$4.0 million with the majority of that spend taking place prior to 2025. In the  
12 forecasted test year ending December 31, 2026, the Company is not projected to  
13 have any spend associated with the SmartCurrents Program as the program will be  
14 closed and will not have any associated customers. The spend associated with the  
15 SmartCurrents Program can be seen on Line 2 of Exhibit A-12, B5.6.

16

17 **Q94. How much capital is the Company forecasting to invest in Other DR Programs**  
18 **and Pilots?**

19 A94. As can be seen on Exhibit A-12, B5.6, the Company is forecasting to spend \$3.1  
20 million in capital during the 24-month bridge period ending December 31, 2025,  
21 and \$0.7 million during the forecasted test year ending December 31, 2026, in Other  
22 DR Programs and Pilots.



Line  
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1 **Q95. What capital investments are included in Other DR Programs and Pilots?**

2 A95. The Other DR Programs and Pilot category on Exhibit A-12, Schedule 5.6, line 3  
3 includes capital spend associated with the C&I Dashboard, C&I Battery pilot and  
4 other capital expenses that may not be tied directly to a program.  
5

6 **Q96. What is the C&I Dashboard?**

7 A96. The Company issued a Request for Proposal in 2023 and is successfully partnering  
8 with Enel North America, Inc. as a result to provide certain C&I interruptible  
9 customers, likely customers taking service under D8, R10 or R12, with technology  
10 to help improve their DR performance during called events. Due to the size of these  
11 customers relative to the DR portfolio, their performance during DR events is  
12 critical to reliability. The technology provides customers with near real-time  
13 telemetry meter data so that a DR event can be monitored prior to, during, and after  
14 an event occurs. The data is displayed on a dashboard that is accessible by both the  
15 customer and the Company. Providing customers with near real-time telemetry will  
16 better equip them to curtail load during DR events in accordance with their  
17 contracted load reduction value. The technology also provides the Company  
18 analytics for better DR forecasting and post-event analysis. The Company  
19 anticipates spending \$1.4M over the bridge period and \$.7 during the forecasted  
20 test period in support of the C&I Dashboard.  
21

22 **Q97. What is the C&I Battery Storage pilot?**

23 A97. The C&I battery storage pilot is a behind-the-meter (BTM) lithium-ion phosphate  
24 battery energy storage system (BESS) that will be located at two customers' sites.  
25 It is designed to test the ability to achieve peak demand shaving or shifting during

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1 DR events. The Company is targeting a two-year pilot period following installation  
2 and commissioning of the batteries.

3

4 **Q98. Can you discuss the main objectives of the C&I Battery Storage pilot?**

5 A98. Yes. The main objectives of the pilot are as follows: Engage with customers to  
6 better understand their interest in hosting and potentially operating a BESS; Gain  
7 operational experience on battery installation, management, and control interfaces  
8 when the system is located at a customer's site as opposed to a Company site;  
9 Assess feasibility for sharing asset control between customer and the Company;  
10 • Evaluate the effectiveness of the BESS to achieve system peak demand  
11 reduction when a DR event is called by the Company;  
12 • Assess customer's actions to achieve demand charge and overall bill  
13 reductions; and  
14 • Facilitate the understanding of multiple energy storage values,  
15 compensation models, and the integration of battery storage in wholesale  
16 markets to support tariff development as contemplated by the  
17 Commission's Order in MPSC Case No. U-21032.

18

19 **Q99. Could you describe the status and progress of the C&I battery pilot?**

20 A99. Both batteries are currently in storage, awaiting the finalization of the skid design  
21 and manufacturing. All other major equipment has been procured and will be  
22 integrated into the skids. The Company continues to work with Hitachi and GTI,  
23 the skid manufacturer, to finalize the skid design layout and controls. The first skid  
24 is scheduled to be manufactured and assembled from January to March 2025  
25 followed by shipment to DTE's Training and Development Center (TDC) in April.

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1 The second skid will be manufactured and shipped approximately 3 months after  
2 the first to allow any learnings from the first skid to be incorporated on the second  
3 skid.

4  
5 As part of the implementation plan, the Company has identified one customer, and  
6 a commercial agreement has been developed and agreed upon. For the second  
7 battery, the DR team supported prospect meetings with large businesses and  
8 institutions to identify a second participant. The resounding sentiment after the  
9 meetings with interested customers was that the post-pilot costs were not palatable  
10 given the projected bill savings. An alternative option for the second battery is to  
11 leverage it internally at one of DTE's locations. The DR team is currently in the  
12 exploration phase of this option and is proposing an asset transfer of the cost of one  
13 battery. The Company plans for both batteries to be operational by the end of 2025.  
14 The initial proposed event schedule includes no more than 30 planned DR events  
15 per year and five short notice DR events, with a least one-hour customer notice, per  
16 year. However, per the order in Case No. U-21297, the Company will meet with  
17 the MPSC Staff to discuss an appropriate number of required test events each year.

18

19 **Q100. Did the Commission approve all capital costs related to the C&I battery pilot**  
20 **in previous cases?**

21 A100. No. In Case No. U-21297, the Commission excluded \$1,990,360 of the capital  
22 spend on the C&I battery pilot because the Company did not intend on signing up  
23 a second customer until the first battery was installed and did not provide a timeline;  
24 thus, Staff did not believe that half the capital would be used and useful in the  
25 projected test year. In 2022, the Company spent \$2.5 million in capital to procure

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1 the equipment for the C&I battery pilot which was partially recovered in Case No.  
2 U-21403 2022 DR Reconciliation. The exclusion included \$1.25 million related to  
3 half of the procured equipment which was spent during the bridge period (2022)  
4 and \$0.75 million in forecasted test year (2023) spend.

5

6 In Case No. U-21534, the Commission disallowed the \$1,990,000 associated with  
7 the second battery but encouraged the Company to continue to seek a second  
8 customer for the battery, which the Company continues to do.

9

10 The Company anticipates spending \$1.1M during the bridge period ending  
11 December 31, 2025, with no capital spend anticipated in the forecasted test year  
12 ending December 31, 2026.

13

14 **Q101. What is the Smart Savers program?**

15 A101. The Smart Savers program, which is a Bring Your Own Device (BYOD) program,  
16 is available to residential and commercial customers who have an existing and  
17 eligible PCT installed at their residence or business. In this program, customers  
18 enroll their eligible thermostat in the program and agree to let the Company adjust  
19 the setpoint on the thermostat up to four degrees during Smart Savers events. Smart  
20 Savers events last no more than four hours and can be called between 12:00 pm and  
21 8:00 pm on non-holiday weekdays. The Smart Savers Program is available year-  
22 round with peak load reduction occurring during the summer season from June 1<sup>st</sup>  
23 through August 31<sup>st</sup>. The Company is limited to 56 event hours annually. There is  
24 no limit on the minimum length of an event, but the maximum event duration  
25 cannot exceed four hours.

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1 **Q102. How much O&M is needed to support the Company's Smart Savers Program**  
2 **going forward?**

3 A102. The Company is projecting to grow the cumulative number of enrolled thermostats  
4 from nearly 74,000 as of December 31, 2024, to nearly 100,000 enrolled  
5 thermostats by the end of 2026. Beginning in 2026, the Company is forecasting to  
6 spend \$3.3 million annually to support the Smart Savers Program. The requested  
7 O&M spend is necessary to support the continued successful growth of the program  
8 the Company has experienced since its inception, including the annual portal fee  
9 and annual device fees, with annual devices fees increasing each year based on the  
10 projected increase in enrollments.

11

12 **Q103. How many additional MWs will the O&M investment in Smart Savers result**  
13 **in?**

14 A103. The continued investment in Smart Savers is projected to grow the MWs associated  
15 with the program by 11 MWs.

16

17 **Q104. How much O&M is the Company forecasting to spend in Pilots and Other**  
18 **Projects?**

19 A104. The Company is forecasting to spend \$2.0 million in O&M to support various DR  
20 pilots, programs and projects. This O&M spend includes Smart Charge and the  
21 residential generator pilot. O&M spend for these programs and pilots supports  
22 labor, marketing and communication efforts as well as portal, dispatch, program  
23 incentive and platform fees. Other DR projects are included in this category as well.

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1 **Q105. Could you describe the history of the electric vehicle (EV) DR or Smart Charge**  
2 **pilot?**

3 A105. The initial design of Smart Charge, which launched in 2019, was to assess the  
4 effectiveness of Open Vehicle Grid Integrated Platform (OVGIP) concept to  
5 integrate EV charging with grid objectives through DR. This initial design ran until  
6 May of 2023.

7

8 After completion of the initial design, the Company modified the focus of the pilot  
9 to incorporate managed charging, starting in July 2023. One of the main reasons  
10 the Company transitioned to managed charging was due to the mandatory roll out  
11 of residential electric time of use (TOU) rates in March 2023. In this phase of the  
12 pilot, the Company's managed charging approach ties each participant's enrollment  
13 to their specific TOU rate schedule and automatically initiates charging to occur  
14 during their off-peak rate period when it's the lowest cost for them and most  
15 beneficial to the system. In addition, the Company is interested to learn if there's  
16 an impact of the Company scheduling participant's daily charging automatically  
17 through vehicle telematics and managed charging participation for them, or if EV  
18 users are already scheduling their charging during off-peak time periods without  
19 the Company's assistance.

20

21 Throughout 2023 and 2024, the Company continued its partnership with Ford,  
22 General Motors (GM), and BMW through the OVGIP while adding a new  
23 partnership with WeaveGrid. WeaveGrid is a platform that connects utilities,  
24 original equipment manufacturers (OEMs), and EV drivers and is the platform that  
25 is used to enroll eligible Tesla drivers into the Smart Charge pilot.

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1 **Q106. Is the Company planning to make Smart Charge a program within the DR**  
2 **portfolio?**

3 A106. No, not at this time. In the Company's last electric rate case, Case No. U-21534,  
4 the Company discussed the plan to expand the current Smart Charge Pilot into a  
5 program within the Company's portfolio. In the Fall of 2024, the Company put out  
6 an RFP to partner with a program implementer to make Smart Charge a program.  
7 After analyzing bids, the Company decided not to convert it to a program at this  
8 time. The Company intends to keep the Smart Charge a pilot while additional value  
9 streams are analyzed.

10

11 **Q107. Has the Commission and MPSC Staff been supportive of the Company's**  
12 **efforts in pursuing a Smart Charge pilot?**

13 A107. Yes. The MPSC Staff and Commission have supported the Smart Charge pilot in  
14 several cases including the 2019 IRP (Case No. U-20471), 2022 Electric Rate Case  
15 (Case No. U-20836), 2023 Electric Rate Case (Case No. U-21297), 2024 Electric  
16 Rate Case (Case No. U-21534 as well the DR Reconciliation Cases beginning with  
17 Case No. U-20521 filed in 2019.

18

19 **Q108. Can you describe the residential home generator pilot?**

20 A108. Yes. The Company is conducting a residential customer-owned natural gas  
21 generator pilot. The pilot leverages Generac Grid Services' platform and utilizes  
22 telemetry to shift customers' electric load to the customers' generator in real-time  
23 during Company called DR events. Customers were prescreened for eligibility to  
24 participate in the pilot and were targeted accordingly. One qualifier to participate  
25 was, "owner has a premium or dealer managed subscription to Mobile Link." This

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1 subscription allows the Company to operate a switch-free program capable of  
2 remote operations such as responding to DR events. Customers have the option to  
3 opt-out of up to two events per calendar year, throughout the duration of the  
4 program. Events can occur on any non-holiday weekday between the hours of 8:00  
5 am and 8:00 pm within any MISO season, can last no more than four hours, and are  
6 limited to 40 hours in total each calendar year. The pilot will conclude in December  
7 2025.

8

9 **Q109. Can you describe the main objectives in pursuing a residential home generator**  
10 **pilot?**

11 A109. Yes. The main objectives of the residential generator pilot are as follows:

- 12 • Determine whether customers would be willing to actively participate and  
13 allow for real-time telemetry to control their generators during an event;
- 14 • Assess the viability of a pilot that can act as a year-round DR asset  
15 responding on short-term notice for peak events;
- 16 • Assess customer receptiveness and the value customers receive from a  
17 residential generator pilot; and
- 18 • Identify and process new learnings that could be applied to current and  
19 future DR offerings.

20

21 **Q110. Is the Commission and MPSC Staff supportive of the Company's efforts in**  
22 **pursuing a residential home generator pilot?**

23 A110. Yes. However, when the pilot was first introduced in Case No. U-20836, MPSC  
24 Staff argued that the Commission should disallow the O&M spending associated  
25 with the residential generator pilot as there was a concern that the pilot was not



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1 developed enough. The Commission ultimately agreed with the MPSC Staff. Since  
2 that order, the pilot has been further developed. The Company took the  
3 recommendation from Staff to benchmark with CMS on their residential generator  
4 pilot and leverage their learnings and experience. In the Company's latest general  
5 rate case, Case No. U-21297, both MPSC Staff and Commission supported the  
6 O&M spend associated with the residential generator pilot, citing the progress the  
7 Company has made in the pilot development.

8

9 **Q111. Could you describe the status of the residential home generator pilot?**

10 A111. Yes. In 2023 the Company launched a 200-participant cap residential customer-  
11 owned natural gas generator pilot, DR Home Generator Program, in partnership  
12 with Generac Grid Services. Recruitment efforts began in July 2023 and continued  
13 through September 2023, resulting in successful enrollment of 197 customers. As  
14 of December 2024, there are 176 customers enrolled in the pilot. Some customers  
15 chose to unenroll, while others were no longer in compliance with the pilot's terms  
16 and conditions. The Company called three events in 2024: March, July, and  
17 December.

18

19 **Q112. Are there any learnings to share from the residential home generator pilot?**

20 A112. Yes. The Company has gathered valuable feedback from post-event surveys and  
21 conversations with customers who have called the support line. Customers enrolled  
22 in the program are engaged and utility-savvy, with some expressing enthusiasm  
23 about the program's benefits and their desire to help their community, while one  
24 customer noted that the incentive was less competitive compared to the Consumers  
25 program offered to their sister. Customers prefer the convenience of bill credits

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1 over gift cards, as they dislike the hassle of gift cards. Event notifications have been  
2 appreciated among customers and most customers also would like to understand  
3 why events are being called, especially in the winter when it is cold.

4

5 **Q113. What are the results of the test events called from the pilot?**

6 A113. Since the pilot's inception, four events have been called: three in the colder months  
7 during the morning and one in the summer during the afternoon. The platform  
8 being used, Concerto, has a ramp-up and ramp-down period of approximately 15  
9 minutes during which the load transfers to and from the generator, which needs to  
10 be taken into consideration when scheduling and dispatching an event. Table 2  
11 displays results from the four test events called to date.

12

13 **Table 2 : Test Events**

| Date                        | Time                   | Observed Peak Demand Reduction (kWh) | Average Reduction Per Customer (kWh) | Customer Opt Outs |
|-----------------------------|------------------------|--------------------------------------|--------------------------------------|-------------------|
| Tuesday, November 28, 2023  | 9:30 a.m. - 11:30 a.m. | 147.32                               | 0.96                                 | 16                |
| Wednesday, March 6, 2024    | 8:30 a.m. - 11:30 a.m. | 157.95                               | 0.81                                 | 12                |
| Thursday, July 25, 2024     | 2:30 p.m. - 6:00 p.m.  | 319.45                               | 1.67                                 | 13                |
| Thursday, December 12, 2024 | 8:30 a.m. - 10:30 a.m. | 133.24                               | 0.76                                 | 12                |

14

15 **Q114. What are the future plans for the residential generator pilot?**

16 A114. Based on the results of the pilot to date, the Company plans to continue the pilot  
17 through 2025 before expanding the pilot into a full program. The Company believes  
18 that the residential generator pilot will add value to the Company's portfolio as it

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1 is a resource that has shown load reduction in each season, has received positive  
2 customer feedback and can reduce load quickly when called upon.

3

4 **Q115. Are there Other DR Projects that are included in the Pilots and Other Projects**  
5 **Category?**

6 A115. Yes. Other DR projects include initiatives that may not necessarily be tied to a  
7 specific program or a pilot. The Company has set up a dedicated DR call center to  
8 field DR specific calls from customers. The Pilots and Other Projects category also  
9 includes necessary costs to support the competitive DR procurement process that  
10 was agreed to in the IRP settlement in Case No. U-21193. The Company forecasts  
11 to spend \$2.0M on DR Pilots and Other Projects in 2026.

12

13 **Q116. Can you summarize the Capital and O&M investment amounts for the**  
14 **Company's DR Portfolio?**

15 A116. Yes. The Company is forecasting to invest \$11.3 million in capital during the bridge  
16 period beginning January 1, 2024, and ending December 31, 2025, and investing  
17 \$4.4 million in capital during the forecasted test period ending December 31, 2026,  
18 and can be seen on Exhibit A-12 Schedule B5.6. In addition, the Company forecasts  
19 O&M spend of \$6.2 million and is broken out by program on Table 3. This overall  
20 level of investment will support the Company's current program offerings such as  
21 CoolCurrents and Smart Savers, as well as allow the Company to conduct and  
22 evaluate pilots to determine if they can become a valuable resource within the  
23 portfolio. This spend also supports other DR related projects.

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1

**Table 3**

| <b>Program</b>    | <b>2026 Forecasted O&amp;M</b> |
|-------------------|--------------------------------|
| Smart Savers      | \$3.3M                         |
| CoolCurrents      | \$0.8M                         |
| Other DR Projects | \$2.0M                         |
| Total             | \$6.2M                         |

2

**Part X: DR Benefits****Q117. What are the benefits of continued investment in DR?**

A117. The capital and O&M investments in DR will support current programs and is projected to add 43 MWs to the Company's DR portfolio. The investment also supports pilots that could potentially become programs within the Company's DR Portfolio, such as the residential generator pilot which would provide a year-round DR resource. In addition, continued investment in Smart Charge and the C&I Battery Pilots allow the Company to deploy and understand new technologies.

11

**Q118. What are the benefits to customers of continued investment in DR?**

A118. As I previously stated in my testimony, 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. Participating customers benefit through discounted rates or bill credits.

20

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1 Continued investment in DR allows the Company to claim additional capacity  
2 credits which reduces any potential need for capacity purchases in the MISO PRA  
3 to meet the Company's Planning Reserve Margin Requirement (PRMR). By doing  
4 so, it potentially avoids having to procure a new capacity resource. The investment  
5 in DR is lower than the Cost of New Entry (CONE) price published by MISO,  
6 providing the customers and the Company of additional capacity at a lower price  
7 than building a new resource.

8

9 **Q119. Does this complete your direct testimony?**

10 A119. 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-21860

QUALIFICATIONS  
  
AND  
  
DIRECT TESTIMONY  
  
OF  
  
JASON E. SPARKS

**DTE ELECTRIC COMPANY**  
**QUALIFICATIONS AND DIRECT TESTIMONY OF JASON E. SPARKS**

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

2     A1.     My name is Jason E. Sparks (he/him/his). My business address is One Energy  
3             Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate  
4             Services, LLC.

6     **Q2.     On whose behalf are you testifying?**

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

9     **Q3.     What is your educational background?**

10    A3.     I graduated from Central Michigan University with a Bachelor of Science in  
11             Business Administration and a Master of Business Administration Degree.

13    **Q4.     What is your work experience?**

14    A4.     I have worked at DTE Energy since 2006, in several positions of increasing  
15             responsibility. From 2006 until 2013, I worked in the Controller's Organization  
16             performing many diverse tasks including processing journal entries, consolidating  
17             budgets, and providing operational support and compliance work. Since 2014, I  
18             have worked in the Customer Service Organization; first as a manager (in Revenue  
19             Management & Protection and then the Call Center), then Director of the Metering,  
20             Billing, and Exceptions teams, and now as Director of Revenue Management and  
21             Protection.

23    **Q5.     What are your current duties and responsibilities?**

24    A5.     As Director of Revenue Management and Protection (RM&P) group for DTE, I am  
25             responsible for the overall direction, strategy, leadership and management of

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1 collections, theft mitigation, and low-income programs for DTE. The RM&P group  
2 is responsible for driving reduced uncollectible expense for DTE Electric and DTE  
3 Gas as well as optimizing Energy Assistance funding for low-income customers.

4

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

7 A6. Yes. I have sponsored testimony in the following cases:

8 U-17999 2016 DTE Gas General Rate Case

9 U-18014 2016 DTE Electric General Rate Case

10 U-20836 2022 DTE Electric General Rate Case

11 U-21297 2023 DTE Electric General Rate Case

12 U-21291 2024 DTE Gas General Rate Case

13 U-21534 2024 DTE Electric General Rate Case



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1 **Purpose of Testimony**

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

3 A7. The purpose of my testimony is to:

- 4 • Provide details of the Company's actual \$100.0 million in Customer Service
- 5 Operation and Maintenance (O&M) expenses for the twelve-month period
- 6 that ended December 31, 2023, and support the Company's projected \$99.9
- 7 million in Customer Service O&M expenses for the projected test year
- 8 period ending December 31, 2026.
- 9 • Explain the details of the Company's Energy Assistance programs &
- 10 advocacy.
- 11 • Provide details of DTE's Low Income Self-sufficiency Plan (LSP).
- 12 • Provide details of DTE's Low-Income Assistance (LIA) credits.
- 13 • Provide details of DTE's Residential Income Assistance credits (RIA).
- 14 • Provide details of DTE's Payment Stability Plan (PSP) pilot.
- 15 • Explain and support the \$48.0 million of projected uncollectible expense.
- 16 • Address the Commission's suggestions regarding customer notice of cash-
- 17 only payment restrictions in its Petition for Rehearing Order in Case No. U-
- 18 21534 dated April 10, 2025.

19

20 **Q8. Are you sponsoring any exhibits in this proceeding?**

21 A8. Yes. I am sponsoring the following exhibits:

| 22 | <u>Exhibit</u> | <u>Schedule</u> | <u>Description</u>                  |
|----|----------------|-----------------|-------------------------------------|
| 23 | A-13           | C5.7            | Projected Operation and Maintenance |
| 24 |                |                 | Expenses – Customer Service         |

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1 A-13 C5.8 Projected Operation and Maintenance  
2 Expenses Customer Service – Uncollectible  
3 Expense

4 A-13 C5.9.2 ACPP and TOD Regulatory Asset Deferrals

5  
6 **Q9. Were these exhibits prepared by you or under your direction?**

7 A9. Yes, they were.

8

9 **Customer Service Operation and Maintenance Expense**

10 **Overview**

11 **Q10. What is the role of Customer Service for DTE Electric?**

12 A10. The Customer Service organization is committed to the creation of a best-in-class  
13 culture of service excellence and operational excellence, which enables us to provide  
14 customers with distinctive levels of service and satisfaction. Through continuous  
15 improvement, defects and gaps in key customer transactions are remediated and  
16 addressed. Technologies, such as digital self-service solutions that enable customers  
17 to complete their transaction and interact with DTE in their channel of choice and  
18 when it is most convenient for them, and advanced analytics, including machine  
19 learning, and AI tools, are being leveraged to deliver and anticipate seamless and  
20 increasingly personalized customer experiences.

21

22 **Q11. What work does Customer Service perform?**

23 A11. Customer Service is responsible for managing the customer support processes for  
24 both DTE Electric and DTE Gas. Customer Service is comprised of two major  
25 groups, Customer Service Operations and Customer Strategy and Technology.

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1 These groups perform served and self-service customer transactions that include but  
2 are not limited to billing and billing exceptions management, payment, collection,  
3 start and stop service, customer tools and programs (e.g., BudgetWise Billing),  
4 community outreach, and the analysis, development, and implementation of  
5 strategies to improve the customer experience, including data analytics, customer  
6 research and customer satisfaction survey management, and deployment of digital  
7 technology platforms and solutions.

8

9 While the Customer Service organization is organized into two groups and the  
10 Customer Service O&M Expense Exhibit, A-13, Schedule C-5.7 is also categorized  
11 into two groups, these do not align one for one. The Customer Service  
12 organization's expenses are mapped to FERC accounts based on those account  
13 standards. For example, some of the Customer Service Operations' supervisory  
14 expenses may fall into both Account 901 and 907. The discussion directly below  
15 describes the structural organization of Customer Service, not the FERC view of the  
16 resulting expenses.

17

18 **Q12. What departments make up Customer Service Operations and what are their**  
19 **functions?**

20 A12. Customer Service Operations consists of the following departments:

- 21 • Contact Center Operations
- 22 • Metering, Billing, & Exceptions
- 23 • Revenue Management & Protection (RM&P)
- 24 • Customer Service Operations Support

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1 Contact Center Operations manages customer requests and inquiries through the and  
2 Customer Representative (CR), Chat and Interactive Voice Response (IVR),  
3 channels for the five key customer transactions (Billing, Collection, Outage,  
4 Payment and Start and Stop Service), answers customer inquiries regarding their  
5 account or customer programs, and responds to emergency and trouble calls.

6

7 Metering, Billing, and Exceptions is responsible for meter reading, residential and  
8 commercial billing, major accounts billing, bill printing and delivery, billing  
9 exception or issue resolution, and billing system oversight and controls. The team is  
10 also responsible for working and resolving any billing issues that include manual  
11 intervention or coordination with DTE field operations such as AMI Operations.

12

13 RM&P manages credit policies, low-income and energy assistance programs,  
14 payment plans, collection-related exceptions, and accounts receivable collection.  
15 RM&P is also responsible for theft investigations and determining accountability  
16 for unauthorized usage.

17

18 Customer Service Operations Support is responsible for quality monitoring and  
19 management and training of Customer Service employees. It also has responsibility  
20 for the overall Continuous Improvement efforts, including managing the Quality  
21 Management System, within the Customer Service organization.

22

23 **Q13. What departments make up Customer Strategy and Technology and what are**  
24 **their functions?**

25 A13. Customer Strategy and Technology consists of the following departments:

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No.

- 1 • Customer Transaction Experience and Customer Service Business Systems
- 2 • Customer Strategy and Reporting and Customer Research
- 3 • Executive Consumer Affairs Center (ECAC)
- 4 • Customer Service Analytics
- 5 • Digital Experience
- 6 • Community Outreach

7

8 **Customer Transaction Experience and Customer Service Business Systems:**

9 This department includes two sub-groups: Customer Transaction Experience and  
10 Customer Service Business Systems.

11

12 Customer Transaction Experience creates strategies, reviews Company internal  
13 business processes and policies, and works cross-functionally within DTE to  
14 improve the customer experience across DTE's five key customer transactions  
15 (Billing, Collection, Outage, Payment and Start and Stop Service) in both the served  
16 and self-service customer channels. They 'own' the customer experience for these  
17 transactions on behalf of the Company and are involved in activities such as  
18 reviewing the current state of customer processes across the five key transactions,  
19 analyzing customer survey and verbatim data, utilizing continuous improvement  
20 tools and conducting in-depth customer journey mapping exercises to identify gaps  
21 and opportunities in the Company's processes and systems that affect the customer's  
22 experience and their ability to successfully complete their transaction. They also  
23 work on improving our customer communications to keep customers informed about  
24 their requests and resolve customer requests in their first contact with DTE.  
25 Customer Transaction Experience also conducts benchmarking to learn from utility

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1 and non-utility peers in designing and implementing effective approaches and  
2 strategies that improve the Company's key customer transactions.

3

4 Customer Service Business Systems provides system and technical support for the  
5 SAP Customer Relationship & Billing (CR&B) system. It is made up of two sub-  
6 groups, System Support and Technical Support. The System Support group  
7 identifies emerging trends in SAP, coordinates business design, manages the  
8 translation of business needs to system design, identifies defects, and supports the  
9 design of solutions. The Technical Support group are experts in functional design  
10 and serve as liaisons to the Information Technology and Services (ITS) organization.  
11 They conduct unit testing, complete simple configuration, support proof-of-concept  
12 designs and pilots, and resolve incident management tickets.

13

14 **Customer Strategy and Reporting and Customer Research:** This department is  
15 comprised of two sub-groups: Customer Strategy and Reporting and Customer  
16 Research. Customer Service Strategy and Reporting performs all the short- and long-  
17 term strategic planning and analysis for the Customer Service organization and the  
18 enterprise-level Customer Service Excellence Priority Committee. They provide  
19 analytical and project support to the highest priority Customer Service and enterprise  
20 customer initiatives. They are also responsible for metric development and scorecard  
21 reporting for the Customer Service and Customer Service Excellence Priority  
22 Committee. Customer Research is responsible for the administration of customer  
23 satisfaction surveys, reporting and benchmarking of internal and external customer  
24 satisfaction surveys, designing and conducting customer focus groups and customer  
25 interviews, and performing customer studies such as customer segmentation.

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1       **Executive Consumer Affairs Center (ECAC):** ECAC resolves escalated customer  
2 issues that are received from the Michigan Public Service Commission, “I Can  
3 Help” (including Media, Government Affairs, Regional Relations, and Employees),  
4 Better Business Bureau, the Attorney General, and DTE’s Website. Through their  
5 work, they provide valuable feedback to all DTE organizations on the sources of  
6 customer dissatisfaction and work cross-functionally to advocate for and remediate  
7 customer issues.

8

9       **Customer Service Analytics:** Customer Service Analytics is responsible for  
10 providing data analytics support across Customer Service, which includes the design  
11 and delivery of data and reports, key customer metrics and dashboards that are  
12 utilized by all the groups. They also perform advanced analytics utilizing tools and  
13 methods such as natural language processing, machine-learning, and descriptive and  
14 predictive statistical analysis to gain insight into customer behavior and preferences  
15 and identify gaps and opportunities to improving the customer experience and  
16 customer satisfaction. The analytical and modeling outcomes provided by this team  
17 is critical to setting and realizing the organization and the Company’s long-term  
18 customer satisfaction targets and objectives.

19

20       **Digital Experience:** Digital Experience is responsible for developing and  
21 implementing the Company’s digital self-service strategy and roadmap to offer  
22 customers the ability to easily transact and interact with DTE in their digital channel  
23 of choice, including the Website, Interactive Voice Response (IVR) and Virtual  
24 Assistants, Mobile App., and Kiosk, at a time that is most convenient for them and  
25 provide customers with a consistent experience across all these channels. Digital

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1 solutions also include the successful delivery of customer notifications based on  
2 customer-provided permissions and preferences. This group ensures that these  
3 messages are well-written, consistent, accurate and timely. Digital Experience also  
4 leverages the data and analysis, customer satisfaction and customer channel surveys,  
5 and the research and analysis provided by other Strategy and Technology groups  
6 and combines them with the latest capabilities offered by our industry-standard  
7 technology platforms, to inform the design and development of the DTE's digital  
8 self-service solutions. The design and development of robotic process automation,  
9 desktop automation and automated assistants are also a sub-group within Digital  
10 Experience.

11  
12 **Community Outreach:** Customer Outreach performs public affairs-type activities  
13 such as identifying communities and customers that require DTE programs and  
14 services and organizing community forums for customers to learn more about and  
15 access our products and services and to also share their needs and concerns,  
16 providing a valuable feedback loop. A major focus area for the group is to connect  
17 our most vulnerable, low-income customers with resources such as energy  
18 assistance and energy efficiency that support them to pay or manage their bill.  
19 Customers who qualify for energy assistance or low-income programs can sign up  
20 to receive emergency relief assistance or enroll in a program, sometimes on the spot,  
21 given agencies are on site with DTE at the community forums.

22  
23 In addition to their formal community initiatives, Customer Outreach supports  
24 health and human service agencies such as United Way and Salvation Army that  
25 distribute assistance to vulnerable Michigan residents. DTE's support of established



Line  
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1 community partners enables them to provide facilities, volunteers, transportation,  
 2 and other resources to achieve additional outreach to our customers, who are living  
 3 under challenging circumstances. Many of the Company's employees advocate for  
 4 customer assistance when they volunteer to support Michigan-based non-profits  
 5 through the Company's enterprise-wide volunteerism program called Care Force,  
 6 which is also managed by this group.

7

### 8 **Historical and Projected Customer Service O&M Expenses**

#### 9 **Q14. What are DTE Electric's projected Customer Service O&M expenses?**

10 A14. DTE is forecasting Customer Service O&M expenses of \$99.9 million for the 2026  
 11 projected test period, which is calculated in Exhibit A-13, Schedule C5.7. This  
 12 amount is calculated using the 2023 actual historical test period expense adjusted  
 13 for rate case eliminations, normalization adjustments, inflation<sup>1</sup>, and other known  
 14 and measurable adjustments.

15

16 **Table 1 Customer Service Operation and Maintenance Expenses**

17

| Major Expense Categories (\$ millions) | 2023 Historical<br>Test Period | 2026 Projected<br>Test Period |
|----------------------------------------|--------------------------------|-------------------------------|
| Customer Accounts                      | 86.5                           | 85.1                          |
| Customer Service and Informational     | 20.9                           | 21.7                          |
| Less Reclass to Regulated Marketing    | (7.4)                          | (6.9)                         |
| <b>Total</b>                           | <b>100.0</b>                   | <b>99.9</b>                   |

<sup>1</sup> Projected inflation cost of \$8.3 million for 2024, 2025, and 2026 O&M expenses was derived by applying the inflation factors supported Witness Uzenski to the adjusted 2023 historical test period amounts in column (h).

Line  
No.

1 The historical and projected expense amounts do not include Energy Waste  
2 Reduction (EWR) Program, also known as Energy Optimization, and LIEAF  
3 expenses, and certain Regulated Marketing expenses.

4

5 **Historical Test Period Rate Case Adjustments**

6 **Q15. Why are EWR Program costs removed from Customer Service expenses?**

7 A15. Since EWR Program O&M expenses have their own distinct recovery mechanism  
8 through surcharges and are reconciled in separate MPSC proceedings, these costs in  
9 the amount of \$177.2 million are being eliminated on line 19 in column (d) in the  
10 instant case. O&M expenses for the Company's EWR program within FERC  
11 accounts 905, 907, 908 and 909.

12

13 **Q16. Why are LIEAF costs removed from Customer Service expenses?**

14 A16. The LIEAF expenses have been eliminated since they are associated with the  
15 remittance of the revenue collected through the LIEAF surcharge. Funds collected  
16 through the surcharge (a state-mandated charge) are remitted directly to the state and  
17 help provide heating assistance to low-income customers. As such, the LIEAF  
18 expenses in the amount of \$24.3 million are being eliminated on line 14 in column  
19 (e).

20

21 **Q17. Why are \$6.9 million in the projected test period O&M expense being**  
22 **reclassified to a Marketing Exhibit and removed from Customer Service**  
23 **expenses?**

24 A17. These costs are related to Major Account Services, which manages customer  
25 relationships for commercial and industrial customers. The costs are re-classified to

Line  
No.

1 Regulated Marketing O&M. This adjustment is shown in Exhibit A-13, Schedule  
2 C5.7 on line 20 in column (n). Company Witness Foley supports recovery of these  
3 costs in his testimony and as shown in Exhibit A-13, C5.9 on lines 1 through 5 in  
4 columns (a) through (l).

5

6 **Q18. How are costs allocated between DTE Electric and DTE Gas for Customer**  
7 **Service?**

8 A18. Customer Service costs are allocated based on utility-specific data that is  
9 representative of the amount of electric- or gas-related work conducted within the  
10 Company. The allocations for the current year are based on actual activity data from  
11 the previous year.

12

13 Call Center Operations, Customer Service Operations Support, and all the Customer  
14 Strategy and Technology groups' expenses are allocated based on the number of  
15 electric and gas customers. For a customer who is both an electric and a gas  
16 customer, that customer is counted as one-half electric and one-half gas. For 2023,  
17 66.08% of these expenses were allocated to DTE Electric.

18

19 Customer Billing expense is allocated between DTE Electric and DTE Gas via two  
20 cost allocation drivers. The first driver is based on the number of electric and gas  
21 customers and the second, used for Meter Reading expenses, is based on the number  
22 of Advanced Metering Infrastructure (AMI) and non-AMI customers. For 2023,  
23 66.08% of Customer Billing expense was allocated to DTE Electric based on the  
24 number of electric and gas customers. Based on AMI and non-AMI customers, the  
25 2023 DTE Electric allocation for Meter Reading expenses was 12.00%.

Line  
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1 RM&P allocates costs based on the number of accounts in arrears. For 2023, 66.43%  
2 of RM&P expenses were allocated to DTE Electric.

3

4 **Q19. What were the total DTE Electric O&M costs related to Customer Service for**  
5 **the 2023 historical test year?**

6 A19. The total O&M cost related to Customer Service for the adjusted 2023 historical test  
7 year is \$100.0 million is shown in Exhibit A-13, Schedule C5.7, line 21, column (h).  
8 A detailed breakdown of the 2023 historical test year actual O&M expense by major  
9 categories, components and FERC accounts, adjusted by rate case eliminations,  
10 normalization adjustments, inflation, and other known and measurable adjustments  
11 is provided in columns (d) through (g).

12

13 **Historical Test Period Normalization Adjustments**

14 **Q20. Can you explain the Normalization Adjustments reflected in column (g) on**  
15 **Exhibit A-13, Schedule C5.7?**

16 A20. Column (g) on line 19 is an O&M increase of \$13.6 million for the normalization of  
17 temporary cost reductions in 2023.

18

19 **Q21. Can you describe the \$13.6 million of temporary costs reductions in 2023?**

20 A21. Yes, the details are listed in Exhibit A-13, Schedule C5.7, lines 22 through 32 and  
21 are discussed below.

22 • A \$7.8 million adjustment to expenses is related to temporary reductions  
23 achieved through reducing service levels, deferring hiring, delaying purchases,  
24 and minimizing or eliminating the use of outside vendor services and contract  
25 labor across the Customer Service organization.

Line  
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- 1 • A \$0.4 million adjustment related to the deferral of material purchases in 2023.
- 2 • A \$1.1 million adjustment came from temporary suspension of 2023 Customer
- 3 Outreach initiatives that provide resources and support to our customers and key
- 4 stakeholders. An example of these activities includes connecting low-income
- 5 customers to energy assistance programs.
- 6 • A \$0.5 million adjustment related to the temporary suspension of travel, training
- 7 and engagement expenses that pertain to conducting research into best-in-class
- 8 practices and approaches to improving customer experience and customer
- 9 satisfaction.
- 10 • A \$0.4 million adjustment came from a reduction in discretionary customer
- 11 satisfaction credits that are applied to customer accounts to remediate a poor
- 12 customer experience based on specific customer feedback related to a Company
- 13 product or service.
- 14 • A \$0.6 million adjustment for the temporary elimination of non-critical
- 15 benchmarking and customer research reports, surveys or studies that are used to
- 16 improve the quality of our customer processes.
- 17 • A \$2.0 million adjustment from the temporary suspension of consulting services
- 18 for the purpose of driving strategic revenue growth aimed at offsetting increase
- 19 in customer rates.
- 20 • A \$0.7 million adjustment related to the temporary suspension of training,
- 21 including travel, for the Major Account Services Team for the purpose of
- 22 learning more about how to aid industrial and commercial customers in
- 23 capturing greater energy efficiency savings.

Line  
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1 These temporary reductions were taken to mitigate the financial challenges  
2 experienced by the Company in 2023 as further discussed by Company Witness  
3 Bruzzano and are not expected to recur in the projected test period.

4

5 **Customer Accounts Expenses**

6 **Q22. What are the primary activities included in the Customer Accounts Expenses**  
7 **category totaling \$86.5 million in historical test period costs?**

8 A22. The Customer Accounts Expenses category is composed of: \$1.1 million for  
9 Supervision (in FERC account 901), \$1.9 million for Meter Reading (in FERC  
10 account 902), and within FERC account 903 in the amounts of \$68.4 million for  
11 Customer Records and Collection, \$11.0 million for Merchant Fees, which is  
12 supported by Company Witness Foley, and \$2.8 million for Customer 360  
13 Regulatory Asset Amortization and \$1.5 million for ACPP / Time of Day Regulatory  
14 Asset Amortization, which are both supported by Company Witness Uzenski.

15

16 **Q23. What is included in Supervision expense?**

17 A23. Supervision expenses within FERC account 901 include Customer Service senior  
18 leadership and support staff labor expenses. The \$1.1 million historical test period  
19 expense is adjusted for \$0.1 million of inflation to arrive at the projected test period  
20 expense of \$1.2 million.

21

22 **Q24. What activities make up Meter Reading expense?**

23 A24. Meter reading expenses within FERC account 902 include external vendors used to  
24 manually read meters that have not been converted to AMI meters and AMI opt-out  
25 meters. These costs also include other back-office support such as route coordinators

Line  
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1 and personnel who are responsible for monitoring the adherence of the contract  
2 terms by the external service provider, handling the weekly service provider billing,  
3 and analyzing meter reading customer complaints. The \$1.9 million historical test  
4 period expense is adjusted for \$0.2 million of inflation to arrive at the projected test  
5 period expense of \$2.0 million.

6

7 **Q25. Which Customer Service departments are included in the \$68.4 million in**  
8 **historical test period costs for Customer Records and Collection Expenses?**

9 A25. The expenses from the following departments are included in Customer Records and  
10 Collection Expenses within FERC account 903:

- 11 • Contact Center Operations
- 12 • Metering, Billing, and Exceptions<sup>2</sup>
- 13 • Revenue Management & Protection (RM&P)
- 14 • Digital Experience<sup>2</sup>
- 15 • Customer Service Operations Support
- 16 • Customer Strategy and Reporting

17

18 An overview of each department's key activities and select customer-focused  
19 improvement initiatives is provided in the next set of questions and answers.

20

21 **Q26. What work activities are comprised in Contact Center Operations?**

22 A26. Much of the activity in the Contact Center Operations organization is customer-  
23 facing. Handling ~3.6 calls million calls in 2023, the organization is on the front-  
24 line of resolving customer requests and processing their transactions through the

---

<sup>2</sup> Metering, Billing and Exceptions and Digital Experience have expenses that are in other FERC accounts such as FERC account 910.

Line  
No.

1 call, chat and IVR channels. Call handling costs include DTE employee and vendor  
2 customer service representatives and varies based on volume, mix of calls handled  
3 internally versus by the vendor, and desired service level (such as % of calls are  
4 answered within 90 seconds). Support staff within Contact Center Operations  
5 perform workload management, route customer calls to the appropriate call queue,  
6 and provide operational support such as call analysis and escalation of calls.

7

8 **Q27. What has been the focus of Contact Center Operations?**

9 A27. The focus of Contact Center Operations is in streamlining the customer experience  
10 in the call, chat and IVR channels through continuous improvement, quality  
11 monitoring, efficient call handling, and effectively using the technological  
12 capabilities of the Contact Center telephony and IVR platform. Operational and  
13 customer call handling experience improvement efforts include select initiatives like  
14 the following:

- 15 • Growing and expanding the Chat experience to handle more transactions and  
16 reduce customer wait times and the cost of handling a customer request or  
17 inquiry.
- 18 • Utilizing workforce management automation tools and applications to provide  
19 real-time CR productivity status to more efficiently and effectively route calls,  
20 schedule breaks, monitor schedule adherence, optimize off-phone activities, and  
21 provide data for near real-time coaching.
- 22 • Leveraging Natural Language Processing technology in the IVR and customer  
23 information to effectively route calls to the most appropriate solution.



Line  
No.

- 1 • Implementing a robust knowledge management system to ensure customers are  
2 provided the most up-to-date and accurate information, leading to faster and  
3 consistent responses and first contact resolution.

4 These technology and digital self-service efforts are supported by IT projects  
5 described in the Customer Service IT capital investments section of Company  
6 Witness Ambrose's direct testimony and exhibits.

7

8 **Q28. What work activities are comprised in the Metering, Billing, and Exceptions**  
9 **group?**

10 A28. The Metering, Billing, and Exceptions group is responsible for obtaining manual  
11 reads on DTE's meters, billing residential, commercial and industrial customers,  
12 printing and mailing customer bills and mailed customer communications, resolving  
13 billing exceptions, including billing investigations, managing billing programs such  
14 as BudgetWise Billing (BWB) and eBill, and developing customer billing tools that  
15 help customer to understand their rates and manage their usage and bill amount.

16

17 **Q29. What components make up the RM&P department?**

18 A29. There are four major components that make up the RM&P organization:

- 19 • Internal & External Collections  
20 • Collection Exceptions  
21 • Energy Assistance Group (EAG)  
22 • Strategy and Reporting and RM&P Staff

Line  
No.

1   **Q30. What are the work activities of Internal and External Collections?**

2   A30. The Internal and External Collections group uses external collection agencies to  
3       perform collection on outstanding arrears to reduce uncollectible expense. Effective  
4       use of this partnership allows the Company to mitigate the impact of uncollectible  
5       expense related to customers who struggle to pay their bill or who have been  
6       disconnected. This is provided in more detail later in my testimony.

7  
8   **Q31. What are the work activities of the Collection Exceptions group?**

9   A31. The Collection Exceptions group focuses on mitigating uncollectible expenses as it  
10       pertains to bankruptcies, probate, sites disconnected for non-payment, unauthorized  
11       usage, and identity theft.

12  
13   **Q32. What are the work activities of the Energy Assistance Group (EAG)?**

14   A32. EAG assists all customers, but with a focus on our most vulnerable, low-income  
15       customers. They manage the Company's low-income programs such as the LSP  
16       Program and the low-income validation process. In 2024, the EAG team completed  
17       59,467 low-income validations and approximately 5,426 medical exception hold  
18       requests. The EAG group also hosts In-Person DTE Neighborhood Pop-Ups and  
19       collaborate with local agencies and organizations to host Community Resource  
20       Fairs. In 2024, they hosted 25 In-Person DTE Neighborhood Pop-Ups, eight  
21       resource fairs within the Metropolitan Detroit Area, and assisted THAW with their  
22       14th Annual Week of Warmth event. These events are crucial for staying connected  
23       with the vulnerable, low-income communities that the Company serves, and  
24       providing case management solutions, energy efficiency education, and utility  
25       payment assistance to customers in need.

Line  
No.

1 **Q33. What are the work activities of the Strategy and Reporting and RM&P Staff?**

2 A33. The Strategy and Reporting RM&P staff is responsible for creating and maintaining  
3 the Customer Service payment plan policies. Also, the team is responsible for  
4 monitoring compliance to collection and payment policies, supporting operational  
5 financial metrics and reporting, and performing data analysis to support collection  
6 policies and the development of new strategies to improve the customer collection  
7 experience.

8

9 **Q34. What work activities are comprised in Customer Transaction Experience and**  
10 **Customer Service Business Systems?**

11 A34. Customer Transaction Experience works within Customer Service and cross-  
12 functionally within DTE to improve the customer experience from end-to-end across  
13 DTE's five key customer transactions (Billing, Collection, Outage, Payment and  
14 Start and Stop Service) in both the served and self-service customer channels. In  
15 addition to strategy development for each of the key transactions, they monitor all  
16 transaction data such as the volume of transactions by channel and the ease by which  
17 customers can complete their transaction and first contact resolution, the number of  
18 handled calls, and the volume of delivery and quality of customer status  
19 notifications. This group also tracks process and system defects or inefficiencies and  
20 conducts call listening and analysis of transaction satisfaction surveys to identify  
21 opportunities to remediate customer dissatisfiers.

22

23 Customer Service Business Systems provides system and technical support for the  
24 SAP Customer Relationship & Billing (CR&B) system through its two sub-groups,  
25 System Support and Technical Support. The System Support group utilizes their

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1 industry and system knowledge to translate business processes into system design  
2 and identify defects to support the design of solutions. The Technical Support group  
3 works closely with ITS to ensure the system is functioning as expected and conducts  
4 testing of minor and major enhancements prior to the changes being pushed into the  
5 production environment and resolve incident management tickets.

6

7 **Q35. What work activities are comprised in Digital Experience?**

8 A35. As discussed earlier, Digital Experience is responsible for developing and  
9 implementing the Company's digital self-service strategy and roadmap to offer  
10 customers the ability to easily transact and interact with DTE in their digital channel  
11 of choice, including the Website, Interactive Voice Response (IVR) and Virtual  
12 Assistants, Mobile App., and Kiosk. They monitor data from the digital channels to  
13 ensure they are working as expected such as the volume of digital transactions  
14 completed by digital channel, the completion rate of digital transactions, the ease by  
15 which customers can complete a digital transaction, and their satisfaction with the  
16 digital channel. In 2024, over 40 million customer transactions were completed in  
17 a digital channel.

18

19 These technology and digital self-service efforts are supported by IT projects  
20 described in the Customer Service IT capital investments section of Company  
21 Witness Ambrose's direct testimony and exhibits.

22

23 **Q36. What are the work activities of Customer Service Operations Support?**

24 A36. Customer Service Operations Support has established, documented, and  
25 implemented a Quality Management System (QMS) which includes processes and

Line  
No.

1 procedures associated with Customer Service. Documented processes are  
2 maintained and continually improved to ensure that the QMS achieves its intended  
3 results. Over 1,000 Customer Service documented processes are included in the  
4 QMS across the various departments.

5  
6 QMS includes a structured quality approach to ensure processes are followed,  
7 continually improved, and operational stability is maintained. Tools used to identify  
8 risks and opportunities may include but are not limited to: Process Failure Mode  
9 Effects Analysis (PFMEA), Strengths, Weaknesses, Opportunities, and Threats  
10 Analysis (SWOT), the Corrective Action Program (CAR), and Customer Journey  
11 Mapping.

12  
13 Additionally, this department conducts training for new Customer Service  
14 employees, provides on-going training to existing employees, designs new training  
15 as needed, and provides quality assurance of customer calls using advanced call  
16 monitoring and recording technology and analytics. These and many other key  
17 activities drive defect prevention and increase customer satisfaction. In 2021, as a  
18 result of driving continuous improvement across the Customer Service organization,  
19 DTE received the world's first ISO 9001:2015 certification awarded to a customer  
20 service organization. The certification, from the International Organization for  
21 Standardization (ISO), recognizes that the Company's employees are highly  
22 focused, motivated, and engaged in providing quality service for their customers.  
23 The Customer Service organization was re-certified in 2024.

Line  
No.

1   **Q37. What are the Customer Records and Collections Expenses for the projected**  
2       **test period?**

3   A37. DTE is projecting \$69.1 million of Customer Records and Collections Expenses in  
4       2026. This projection is based on actual historical test period expense of \$60.1  
5       million. A \$8.3 million normalization adjustment is made to this expense, as noted  
6       above, for one-time items that occurred in 2023, reducing actual O&M expense.  
7       Reversing these one-time items, results in a historical test period expense of \$68.4  
8       million. This amount is then increased by \$6.7 million to reflect expected inflation  
9       between 2023 and 2026. To arrive at the final projected test period expense of \$69.1  
10      million, after two additional adjustments are made, equaling \$6.0 million in expense  
11      reductions.

12           1. VSIP Savings: DTE has reduced this expense by \$2.5 million in savings.  
13           DTE estimates that this will be the net Customer Service savings related to  
14           its Voluntary Separation Incentive Program. Company Witness Leslie  
15           supports this in her Exhibit A-30, Schedule T1.

16  
17           2. Digital Investment Call Reduction Savings: DTE is projecting its Contact  
18           Center O&M expense will have a savings of \$3.5 million as customers  
19           increase their utilization of digital self-service solutions to complete their  
20           transactions in lieu of calling the Contact Center. These savings will result  
21           from IT capital investments that were approved in Case No. U-21297 and  
22           completed through 2024 as well as from new investments supported by  
23           Company Witness Ambrose in the instant case.

Line  
No.

1 **Q38. How do savings arise from Digital Investment?**

2 A38. These savings arise from past and planned IT capital investments in digital self-  
3 service projects that increase the ability of customers to complete their transaction  
4 or interact with the Company in a digital self-service solution. DTE Electric projects  
5 handled call volume reductions of ~458,000 calls between 2024 and 2026. This  
6 reduction in calls translates to ~\$5.3 million in Contact Center O&M cost reduction  
7 at the \$11.55 per call (2024 cost). DTE Electric's share of these savings equals  
8 ~\$3.5 million in O&M cost reduction in the projected test period.

9

10 **Q39. How much of the projected call volume reduction can be attributed to past**  
11 **capital investments?**

12 A39. The Company considers past capital investments to be those that occurred before  
13 2025. The projected 2024-2026 call volume reduction from IT capital investments  
14 that have not previously been disallowed for recovery and the Company's efforts to  
15 drive customer adoption in its digital self-service solutions is ~322,000 calls through  
16 2025. The digital call volume reduction savings to DTE Electric would equal ~\$2.5  
17 million. The remaining reductions are from projects occurring in 2025 and 2026. If  
18 the IT capital expenditures that these reductions are predicated upon are disallowed  
19 in the instant case, the corresponding savings should be removed as an adjustment.

20

21 **Q40. What call volume reduction is DTE Electric projecting based on capital**  
22 **investments that will occur in the bridge and projected test period of the instant**  
23 **case?**

24 A40. The Company is investing a total of \$14.4 million, \$7.9 million in bridge period and  
25 \$6.5 million in test period capital, across four projects. These include one of the

Line  
No.

1 2024 Advanced Analytics Use Cases (\$0.9 of \$1.5 million) on line 11 and three Web  
2 self-service projects on lines 18, 26, and 27, in Exhibit A-12, Schedule B5.7.3,  
3 supported by Company Witness Ambrose testimony. These Customer Service IT  
4 investments and the Company's efforts to increase utilization of these solutions by  
5 our customers are projected to reduce 215,000 handled calls in 2025-2026, resulting  
6 in \$1.6 million in DTE Electric savings in the 2026 projected test period. If these  
7 IT capital projects are not approved in the instant case, the corresponding savings of  
8 \$1.6 million should not be reflected in the projected test period and should be added  
9 back as an O&M expense.

10

11 **Q41. What expenses are included in the Customer Collection – Merchant Fees?**

12 A41. Merchant fees include the fees that credit card companies charge the Company to  
13 process a credit card payment made by our customers on their account. Historical  
14 test period merchant fees expenses on line 6, column (h) is in the amount of \$11.0  
15 million. Projected adjustments for merchant fees are estimated to be a reduction of  
16 \$3.9 million and is shown on Exhibit A-13, Schedule C5.7, line 6, column (l) for a  
17 net projected test period expense of \$7.0 million. Company Witness Foley is  
18 supporting the Merchant Fees expenses in his testimony in the instant case and  
19 provides more details related to their historical test period, projected adjustment, and  
20 projected test period O&M expenses.



Line  
No.

1   **Q42. Can you please explain the estimated \$3.0 million in projected test period**  
2       **impact to the Customer Service Regulatory Asset for the Advanced Customer**  
3       **Pricing Pilot (ACPP) and Time of Day (TOD) Alternative Full**  
4       **Implementation?**

5   A42. As explained by Company Witness Uzenski, the Company deferred certain O&M  
6       expenses related to the implementation of its ACPP / TOD rate offering. The \$3.0  
7       million of expense represents the recovery of the deferred costs over five years. See  
8       Uzenski Exhibit A-13, Schedule C5.9.3 for the detailed calculation.

9

10   **Q43. What are the impacts to the Customer Service Regulatory Asset from the**  
11       **Company's TOD Alternative Full Implementation?**

12   A43. The Customer Service operational impacts of the TOD Alternative Full  
13       Implementation included resource requirements to handle an estimated incremental  
14       430,000 additional calls in the Contact Center, and an additional 250,000 of billing  
15       exceptions. The 2023 one-time \$5.1 million incremental costs in Customer Service  
16       related to these initiatives are shown in Exhibit A-13, Schedule C5.9.2, on line 11 in  
17       column (f). The 2023 Customer Service IT- related costs of \$0.9 million are shown  
18       in Exhibit A-13, Schedule C5.9.2, on line 9 in column (f).

19

20   **Customer Service and Informational Expenses**

21   **Q44. What are the primary components under the Customer Service and**  
22       **Informational Expenses category?**

23   A44. The Customer Service and Informational Expenses category is primarily made up of  
24       activities related to Supervision (\$3.2 million in historical and \$3.6 million in  
25       projected test period costs) shown on line 13, within FERC account 907, Customer

Line  
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1 Assistance (\$12.3 million in historical and projected test period costs) shown on line  
2 14, within FERC account 908, and Miscellaneous Customer Service and  
3 Informational Expenses (\$5.3 million in historical and \$5.9 million in projected test  
4 period costs) shown on line 16, within FERC account 910. The \$20.9 million  
5 historical test period Customer Service and Informational Expense is adjusted for  
6 \$2.0 million of inflation and a \$1.2 million reclassification to Marketing, Exhibit A-  
7 13, Schedule C5.9, as explained above, to arrive at the projected test period expense  
8 of \$21.7 million.

9

10 **Q45. What are included in the \$3.2 million in historical and \$3.6 million in projected**  
11 **test period costs in Supervision expenses?**

12 A45. Excluding the \$1.2 million in Energy Waste Reduction Program historical test  
13 period adjustment shown in column (d) as explained above, most of the historical  
14 and projected test period costs are related to Regulated Marketing activities for  
15 internal and external stakeholders; these costs are supported by Company Witness  
16 Foley testimony and Exhibit A-13, Schedule C5.9 in the instant case.

17

18 **Q46. What are the primary components that comprise the \$12.3 million in historical**  
19 **and projected test period costs in Customer Assistance Expenses?**

20 A46. Excluding the \$81.3 million in Energy Waste Reduction Program and \$24.3 million  
21 in LIEAF adjustments that are shown in columns (d) and (e), respectively, from the  
22 historical test period costs discussed earlier in my testimony, there are two major  
23 components that make up the \$12.3 million in historical and projected test period  
24 expenses within FERC account 908:

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- 1 • Regulated Marketing costs, of which \$1.2 million of the projected test period
- 2 expenses are being re-classified, are sponsored by Company Witness Foley in
- 3 his testimony and Exhibit A-13, Schedule C5.9 in the instant case.
- 4 • Customer Service costs are related to expenses in Community Outreach, ECAC
- 5 and Customer Research.

6

7 **Q47. Can you describe the Customer Assistance activities performed by Customer**  
8 **Service departments?**

9 A47. Yes. These activities were performed by Customer Outreach, ECAC and Customer  
10 Research and are described below.

11

12 Community Outreach: As discussed earlier in my testimony, this group organizes  
13 community forums for customers, especially our most vulnerable, low-income  
14 customers, to learn more about and access resources such as energy assistance and  
15 energy efficiency that support them to pay or manage their bill. Customers who  
16 qualify for energy assistance or low-income programs can sign up to receive  
17 emergency relief assistance or enroll in a program at the community forums.

18

19 ECAC: As discussed earlier, ECAC resolves escalated customer issues that are  
20 received from the Michigan Public Service Commission, "I Can Help" (including  
21 Media, Government Affairs, Regional Relations, and Employees), Better Business  
22 Bureau, the Attorney General, and DTE's Website. While the volume of work can  
23 vary based on storms, weather and high bills, or implementation of major projects  
24 or changes in rates, the group resolves thousands of external cases annually.

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1 Customer Research: As discussed earlier in my testimony, Customer Research is  
2 responsible for the administration, reporting and benchmarking of internal and  
3 external customer satisfaction surveys, conducting customer focus groups and  
4 customer interviews, and performing recurring and ad-hoc customer studies to  
5 support development of customer initiatives across Customer Service and the  
6 Company.

7

8 **Q48. What expense is DTE projecting for Customer Assistance?**

9 A48. DTE Electric forecasts \$12.3 million for the 2026 projected test period Exhibit A-  
10 13, Schedule C5.7, line 14, column (n). This amount is calculated by taking the  
11 historical period expense, less EWR, LIEAF, and increased by normalization  
12 adjustment for Marketing expenses, to total \$12.3 million, and adding \$1.2 million  
13 for inflation and subtracting \$1.2 million of marketing expense that is re-classified  
14 and discuss above. DTE Electric anticipates this expense will remain flat from the  
15 historical period to projected test period.

16

17 **Q49. What are the primary work activities that are comprised in Miscellaneous**  
18 **Customer Service and Informational Expenses?**

19 A49. These activities include O&M expenses from the following departments: Customer  
20 Transaction Experience and Customer Business Systems, Digital Experience,  
21 Customer Service Analytics and Metering, Billing and Exceptions. The historical  
22 test period expense of \$5.3 million is adjusted for \$0.5 million in 2024-2026  
23 inflation to arrive at \$5.9 million in the projected test period.

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1 **Customer Service Projected Test Period O&M Expense Summary**

2 **Q50. What is the total amount of Customer Service O&M expenses that DTE**  
3 **Electric seeks to recover in rates for the projected test period?**

4 A50. DTE Electric seeks to recover \$99.9 million in Customer Service O&M expenses in  
5 the 2026 projected test period as shown in Exhibit A-13, Schedule C5.7, line 21,  
6 column (n). This exhibit provides a detailed breakdown of the projected test period  
7 O&M expenses that the Company is requesting in this case.

8  
9 **Q51. What costs are included in the \$99.9 million of Customer Service O&M**  
10 **expenses in column (n)?**

11 A51. Starting from the adjusted 2023 historical test period Customer Service O&M  
12 expenses shown in column (h) of \$100.0 million discussed earlier in my testimony,  
13 the Company has made projected adjustments that include \$8.3 million for 2024-  
14 2026 inflation on line 21 in columns (i) through (k), a \$3.9 million reduction for  
15 merchant fees on line 6 in column (l), a \$6.0 million reduction in Customer Record  
16 and Collection expenses on line 5 in column (l), \$1.5 million in amortization expense  
17 associated with the TOD Regulatory Asset on line 8 in column (l), and a reduction  
18 of \$1.2 million in Customer Assistance Expenses on line 14 in column (l) to arrive  
19 at the 2026 projected test period Customer Service O&M expense of \$99.9 million  
20 in column (n).

21

22 **Energy Assistance Programs & Advocacy**

23 **Q52. What is the goal of the Company's energy assistance programs?**

24 A52. DTE Electric's energy assistance programs are designed to align with the definition  
25 of "affordability" adopted in the Commission's December 21, 2023, Order in Case

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1 No. U-20757 (p. 36). This definition describes affordability as “the extent to which  
2 a household has the resources to meet their home energy needs for heating, cooling,  
3 and other uses in a healthy, sustainable, and energy-efficient manner without  
4 compromising their ability to meet other basic needs.”

5

6 With this framework in mind, DTE Electric’s energy assistance programs are  
7 structured to achieve several key objectives, including:

8

9 **Sustained Energy Access:** The foremost objective is to ensure that customers,  
10 particularly those with low incomes, have continued access to essential energy  
11 services. Our programs strive to prevent service interruptions and help customers  
12 maintain a reliable household energy source.

13

14 **Arrears Reduction:** These programs aim to alleviate customer arrears, which are  
15 outstanding or overdue payments. By focusing on reducing accumulated arrears, the  
16 burden on customers is eased, enabling them to manage their financial obligations  
17 more effectively.

18

19 **Payment Habit Encouragement:** DTE Electric’s initiatives are designed to  
20 promote responsible payment behaviors among participants. By offering affordable  
21 monthly payments, these programs assist customers in establishing a habit of regular  
22 bill payments.

23

24 **Consumption Reduction:** DTE Electric provides energy efficiency education and  
25 awareness of EWR (Energy Waste Reduction) offerings by enhancing

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1 communications and messaging while leveraging new digital and social media  
2 communication trends. DTE Electric is also using targeted marketing to meet  
3 segment-specific needs for energy efficiency information while using traditional  
4 mass media focused on the benefits of energy efficiency improvements.

5

6 **Short-Term Assistance:** While long-term sustainability options are preferred, the  
7 programs provide short-term assistance to help customers bridge the gap during  
8 periods of financial strain. This assistance is intended to alleviate immediate  
9 challenges while participants work toward self-sufficiency.

10

11 **Empowerment and Self-Sufficiency:** Ultimately, the programs aspire to empower  
12 customers to become self-sufficient in managing their energy-saving practices. By  
13 guiding participants toward better financial management and energy-saving  
14 practices, the programs equip customers with the tools to afford the actual costs of  
15 their energy consumption over time.

16

17 **Community Collaboration:** Collaboration with external entities, such as social  
18 service agencies, government departments, and community organizations, is a  
19 central aspect of these programs. This collaboration helps identify eligible  
20 participants, tailor assistance strategies, and generate effective solutions for present  
21 and future energy challenges.

22

23 In summary, DTE Electric's commitment to making energy more affordable by  
24 helping customers meet their home energy needs in a way that is sustainable,

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1 efficient, and does not compromise their ability to cover other essential expenses,  
2 fully aligning with the Commission's vision of affordability.

3

4 **Q53. What energy assistance programs does the Company provide to its customers?**

5 A53. The Company offers several energy assistance programs: an Affordable Payment  
6 Plan (APP), known as the Low-Income Self Sufficiency Program (LSP), Residential  
7 Income Assistance (RIA) credits and Low-Income Assistance (LIA) credits.  
8 Additionally, to further understand and meet the energy affordability needs of our  
9 customers, the company offered the Payment Stability Plan (PSP) pilot from 2022  
10 to 2024 that was approved in Case No. U-20929. I will discuss these programs in  
11 further detail in my testimony.

12

13 **Q54. What is the Company's advocacy role for Energy Assistance at the State and**  
14 **Federal level?**

15 A54. The Company plays a proactive leadership role in advocating for energy  
16 affordability for vulnerable customers at both state and federal levels.

17

18 In 2024, the Company supported an increase to federal energy assistance funding  
19 through the Low-Income Home Energy Assistance Program (LIHEAP) and to  
20 ensure Michigan continues to receive critical funding levels. As a governance board  
21 member of the National Energy Utility and Affordability Coalition (NEUAC)—a  
22 nationwide coalition bridging states, utilities, and social services to aid families in  
23 energy crises—the Company actively participates in national advocacy efforts.  
24 Additionally, through membership in trade associations such as the Edison Electric



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1 Institute, the Company has championed federal energy assistance as a top industry  
2 priority.

3  
4 At the state level, the Company has a longstanding commitment to energy assistance  
5 advocacy. Its representatives have served on the boards of key community  
6 organizations, including The Heat and Warmth Fund (THAW) and United Way,  
7 reinforcing a shared mission of supporting customers in need. Recently, the  
8 Company took a lead role in advancing state legislation, that was passed in  
9 December, to more than double available Michigan Energy Assistance Program  
10 (MEAP) funding and expand eligibility to better serve struggling households.

11  
12 Furthermore, the Company's Energy Advocacy Group (EAG) maintains close,  
13 ongoing collaboration with community partners—including THAW, United Way,  
14 Michigan Community Action Agency, The Salvation Army, St. Vincent DePaul,  
15 True North, and the Coalition to Keep Michigan Warm—to develop innovative  
16 customer support solutions. As part of these efforts, the Company recently hosted  
17 its annual Community Partner Energy Assistance Training Program, equipping  
18 partners with the latest updates for the 2024/2025 energy assistance year.

19  
20 Through these strategic initiatives, the Company remains deeply committed to  
21 securing and expanding energy affordability resources for those most in need.

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1   **Q55. How does the Company raise customer awareness of energy assistance**  
2       **programs and connect them to available resources?**

3   A55. In addition to digital and print communications, our direct customer outreach  
4       programming includes DTE-hosted neighborhood pop-ups, community resource  
5       fairs, community open houses, and outreach via neighborhood block clubs,  
6       homeowners' associations, and faith-based organizations. Finally, the Company  
7       frequently engages with State agencies, including the Michigan Department of  
8       Health and Human Services (MDHHS) and the MPSC, to partner on strategies to  
9       better deliver energy assistance to those in need.

10

11   **Q56. What efforts has DTE Electric taken to maximize the benefits available to the**  
12       **greatest number of its most vulnerable low-income customers?**

13   A56. To support our low-income customers, the Company has developed a plan to ensure  
14       that customers are aware of available State funding and are prepared to make their  
15       application to the State.

16

17       During 2024, the Company executed e-mail and outbound calling campaigns  
18       encouraging potentially eligible customers to apply for available State funding. The  
19       Company also held customer assistance days and resource fairs at local community  
20       centers and faith-based organizations to assist customers with the State application  
21       process. In addition, service disconnects were paused over the holiday season and  
22       the Company proactively reached out to senior customers informing them of their  
23       rights to obtain protection from disconnect during the winter season due to their  
24       eligibility for the Senior Winter protection program. Finally, the Company led a

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1 United Way campaign and THAW funding drives at DTE Electric which support  
2 our vulnerable customers.

3

4 **Q57. Can you provide details on the Company's customer outreach activities to**  
5 **ensure customers are aware of available energy assistance??**

6 A57. The Company has a robust multi-faceted approach to inform customers of available  
7 energy assistance:

8

9 **Customer Resource Fairs**

10 DTE Electric hosts in-person Community Resource Fairs to allow customers to  
11 interact with representatives to address inquiries and obtain hands-on assistance.

12 During these events, we partner with the Michigan Department of Health and  
13 Human Services and other agencies, such as The Heat and Warmth Fund (THAW)  
14 and the Wayne Metropolitan Community Action Agency, to provide case  
15 management solutions, energy efficiency education, and energy assistance to  
16 customers in need. Resources provided at Customer Resource Fairs include:

- 17 • Help with applying for energy assistance (State Emergency Relief)  
18 • Tips to help customers reduce their energy bills  
19 • Access to various human services agencies

20

21 **Community Pop-ups**

22 As we continue to raise awareness of the many initiatives and programs DTE Energy  
23 offers its most vulnerable customers, we hosted twenty Community Pop-ups from  
24 February to November 2024. These customer-facing events were conducted monthly  
25 with in-person support from specialized DTE Electric representatives to address

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1 inquiries and provide bill payment assistance at locations including the Northwest  
2 Activities Center and Southfield Pavilion.

3

4 **Community Outreach**

5 DTE has a robust partnership with The Heat and Warmth Fund (THAW),  
6 collaborating on numerous initiatives to raise awareness and increase access to  
7 energy assistance. Traditionally, DTE collaborates with THAW on its annual Week  
8 of Warmth to kick off the Season of Need and assist families with energy burdens  
9 across the state. THAW's Week of Warmth program culminates with the Night of  
10 Warm Hearts Gala at DTE Energy Headquarters. In October 2024, DTE joined  
11 THAW for the Neighborhood Energy Efficiency Day (NEED) held in the Yorkshire  
12 Woods neighborhood at the Sound Mind Sound Body Community Engagement  
13 Center. Services provided included home energy assessments, payment plan  
14 enrollments, navigation with State Emergency Relief (SER), and free smoke  
15 detectors and energy efficiency kits. Also, DTE volunteers participate annually in  
16 the Gift of Warmth Telethon to raise donations to help households achieve energy  
17 stability.

18

19 **Senior Community Outreach**

20 Each year, the Company engages in proactive outreach to protect senior customers  
21 for the winter season. For example, the 2024-2025 Senior Winter Protection Yearly  
22 Campaign began on October 1, 2024. During this campaign, DTE's goal was to  
23 protect eligible senior citizens, age 65 or older, from a disconnection of service in  
24 alignment with the heating season months (November 2024 through March 2025) at  
25 the senior's documented personal residence. To ensure service was restored for these

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1 protected seniors, DTE contacted more than 1,500 seniors and conducted almost  
2 1,200 site visits. In addition, eligible seniors were encouraged to seek energy  
3 assistance to address or prevent accumulating arrears.

4

5 **Internal Training and Referrals**

6 Each year, DTE's Energy Advocacy Group (EAG) and the broader Customer  
7 Service Representative team's complete refresher training on the Company's energy  
8 assistance offerings. This training process provides Customer Service  
9 Representatives with the tools to support our low-income customers and the  
10 pathways to transfer them to our specialized EAG team for more in depth low-  
11 income support.

12

13 **Additional Outreach**

14 DTE employs many additional methods to disseminate information on energy  
15 assistance to its customer base, including:

- 16 • Digital channels and web resources where customers can find information  
17 about energy assistance and self-service transactions.
- 18 • Automated calls, email blasts, and letter campaigns are widely used to share  
19 information on the availability of energy assistance.
- 20 • Annual energy assistance brochure that outlines all available DTE programs  
21 offered, with Arabic, Bengali, Mandarin and Spanish translations available.
- 22 • Referrals to Michigan 2-1-1 (a free service that connects Michigan residents  
23 with resources for utility assistance, food, shelter, health, and more).

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1 **Low Income Self-Sufficiency Program (LSP)**

2 **Q58. What is the Company's Affordable Payment Plan?**

3 A58. LSP is the Company's Affordable Payment Plan. It is a 2-year payment plan for  
4 vulnerable families at or below 150% Federal Poverty Level (FPL) that provides  
5 affordable monthly payments based on income and energy usage. The Company  
6 partners with social service agencies and the State of Michigan to further support  
7 and promote LSP. The LSP program provides comprehensive support that helps  
8 eligible customers afford their utility service. This comprehensive support includes  
9 wrap-around services from agency partners in the form of education, energy  
10 efficiency, and other self-sufficiency services over the course of their participation.  
11 While participating in the plan, customers have the benefit of sustained energy. The  
12 plan eliminates any future late payment charges, and past due energy charges are  
13 frozen while the customer receives a monthly arrears forgiveness credit.  
14 Additionally, a dedicated team of customer advocates within the Company are ready  
15 to assist customers while enrolled in LSP.

16

17 **Q59. How long has the Company offered LSP to its customers?**

18 A59. Public Act 615 of the Michigan Public Act of 2012 established the Michigan Energy  
19 Assistance Act requiring the MDHHS to administer the Michigan Energy Assistance  
20 Program (MEAP). Since that time, the MEAP program has funded the Companies'  
21 LSP program.

22

23 **Q60. Have there been recent changes to LSP?**

24 A60. Yes, in 2023, the MPSC took measures to align utilities on eligibility and the  
25 administration of APPs. As a result, several changes were made to LSP. See the table

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1 below. Additionally, proposed changes to the Company's energy assistance  
2 programs are outlined in docket U-20929.

3

4

**Table 2**  
Affordable Payment Plan Alignment Update - Changes to LSP

| Components                        | Existing LSP – Fixed Customer Payment                                                                                                                                                                                                                         | New LSP – Modified Budget Billing Plan                                                                                                                                                                                                                                                                                             |
|-----------------------------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Plan Length                       | 24 Months                                                                                                                                                                                                                                                     | 24 Months                                                                                                                                                                                                                                                                                                                          |
| Federal Poverty Level (FPL) Tiers | <ul style="list-style-type: none"> <li>• 20-75 %</li> <li>• 76-110%</li> <li>• 111-150%</li> </ul>                                                                                                                                                            | <ul style="list-style-type: none"> <li>• 1-19%<sup>1</sup></li> <li>• 20-75 %</li> <li>• 76-110%</li> <li>• 111-150%</li> </ul>                                                                                                                                                                                                    |
| Consumption Cap                   | <ul style="list-style-type: none"> <li>• \$1,600 for Electric Only</li> <li>• \$2,150 for Gas Only</li> <li>• \$3,750 for a Dual Commodity</li> </ul>                                                                                                         | No cap as the customers plan amount is reflective of their unique usage.                                                                                                                                                                                                                                                           |
| Arrears Forgiveness               | <ul style="list-style-type: none"> <li>• Arrears are frozen at the time of enrollment and paid off monthly.</li> <li>• \$3,000 arrears cap</li> </ul>                                                                                                         | <ul style="list-style-type: none"> <li>• Upfront arrears forgiveness payment of up to \$600.</li> <li>• A 2<sup>nd</sup> Arrears payment of up to \$600 at 12 months.</li> <li>• A final arrears payment of \$1,800 at the completion of the plan.</li> <li>• No arrears cap.</li> </ul>                                           |
| Monthly Gap Payment               | A credit is provided to offset the difference between the actual billed usage and the customer's plan amount.                                                                                                                                                 | <ul style="list-style-type: none"> <li>• A flat monthly credit is provided to subsidize the customer's plan amount to make it more affordable than a traditional budget billing plan.</li> <li>• A reconciliation credit will be provided at the 12-month settlement to avoid additional customer burden.</li> </ul>               |
| Plan Calculation                  | <ul style="list-style-type: none"> <li>• The customer's plan amount is based on the customer's FPL and usage but is not unique to the customer.</li> <li>• The customer's plan amount is set at enrollment and only changes if the customer moves.</li> </ul> | <ul style="list-style-type: none"> <li>• The customer's plan amount is based on their average monthly consumption and reduced by an agency credit chosen based on the customer's FPL.</li> <li>• The customer's plan amount is re-evaluated every 6 months and can change based on the customer's consumption behavior.</li> </ul> |

1. FPL Customers between 1-19% FPL requires MPSC approval in the existing LSP format.

5

6 **Q61. How does the Company measure success for the current LSP program?**

7 A61. In the current LSP program, a household is considered successful when completing  
8 the fiscal year without being removed for nonpayment.

9

10 **Q62. Will the Company change how it measures success of the modified LSP?**

11 A62. Yes. The MPSC led Affordable Payment Plan Alignment subcommittee is working  
12 towards providing new metrics to define success of the modified LSP. This will  
13 include the definition of graduation and plan success over multiple fiscal years.

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1 **Payment Stability Plan**

2 **Q63. What was the Payment Stability Plan (PSP) pilot?**

3 A63. The PSP pilot was a percentage of income-based program directed at low-income  
4 customers at or below 200% of the Federal Poverty Level (FPL). PSP was created  
5 by order U-20929 in 2020 and was a 2-year pilot that launched in the first quarter of  
6 2022.

7  
8 The pilot focused on the importance of affordable energy as it relates to energy  
9 burdens for low-income customers. Customers who received either gas or electric  
10 utility service from DTE Gas or DTE Electric had a flat bill payment equivalent to  
11 6% of their household gross income. Customers who received both gas and electric  
12 utility service from the Company had a flat bill payment equivalent to 10% of their  
13 household gross income.

14

15 **Q64. Has the Company provided any reporting on the PSP pilot?**

16 A64. Yes, in collaboration with the MSPC, the Company provided a comprehensive  
17 report of outcome metrics, customer feedback and recommended next steps for the  
18 PSP program as well as potential impacts to other energy assistance programs in  
19 January 2025. This report was filed to docket U-20929.

20

21 **Low-Income Assistance Credits**

22 **Q65. What other methods of assistance are there for low-income customers?**

23 A65. Other key programs that address energy sustainability for our low-income customers  
24 are the RIA and LIA assistance credits.



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1   **Q66. What Low-Income Assistance Credits does DTE Electric offer?**

2   A66. DTE Electric offers two credits, the Residential Income Assistance Credit and the  
3       Low-Income Assistance Credit. These credits were developed under Act 3 MCL  
4       460.11(2). This law provides for recovery of revenue shortfalls resulting from these  
5       credits to be recovered across all rate classes.

6

7   **Q67. Who is eligible for these low-income assistance credits?**

8   A67. Eligibility for the credits is established in Section 10t of MCL 460.10t 6(b). This  
9       section defines “Eligible low-income customer” as a customer whose household  
10      income does not exceed 150% of the poverty level, as published by the United States  
11      Department of Health and Human Services, or who receives any of the following:

12       (i) Assistance from a state emergency relief program.

13       (ii) Food stamps.

14       (iii) Medicaid.

15

16   **Q68. How do eligible customers qualify for these low-income assistance credits if**  
17       **they do not receive any of the other forms of assistance listed above?**

18   A68. Customers can also provide documentation for self-attestation to determine  
19       eligibility for these credits.

20

21   **Q69. Has the recent passage of State MEAP Reform (Michigan Public Acts 168, 169,**  
22       **170 & 198 of 2024) impacted DTE’s low-income energy assistance programs?**

23   A69. DTE closely partners with State agencies and community partners on our energy  
24       assistance offerings. Impacts from the Michigan public acts listed above will be

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1 implemented through dialogue and partnership with these key stakeholders  
2 throughout 2025.

3

4 Residential Income Assistance Credit

5 **Q70. What are the key features of the RIA credit?**

6 A70. The RIA credit offers low-income electric customers a per month credit on their bill  
7 that is equivalent to the electric service charge. To be eligible, the total household  
8 income cannot exceed 150% FPL, as verified by an authorized State or Federal  
9 agency. The credit is renewed annually based on eligibility requirements. Customers  
10 may not receive both an electric RIA and electric LIA credit at the same time.

11

12 **Q71. Is the Company proposing any eligibility changes to the RIA credit?**

13 A71. Not in this filing. However, proposed changes to the Company's energy assistance  
14 programs are outlined in the Company's January 29, 2025, report filed in docket U-  
15 20929.

16

17 **Q72. How can a customer become enrolled to receive the electric RIA credit?**

18 A72. Customers who receive energy assistance in the form of a Home Heating Credit  
19 (HHC), State Emergency Relief (SER), or one time assistance are automatically  
20 enrolled to receive the RIA credit.

21

22 **Q73. How is a customer who is not a recipient of the above-mentioned energy**  
23 **assistance able to enroll to receive the RIA credit?**

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1 A73. Households that do not receive energy assistance in the form of HHC, SER, or one  
2 time assistance by an agency may provide documentation validating their eligibility  
3 and be manually enrolled.

4  
5 **Q74. How does DTE Electric reach out to households not automatically enrolled for**  
6 **the RIA credit?**

7 A74. As stated above, the Company has many ways that it reaches out to customers who  
8 may have a need for energy assistance including the following. Please see above for  
9 additional details of the Companies customer outreach efforts.

- 10 • Customer resource fairs
- 11 • Community pop-ups
- 12 • Community outreach
- 13 • Senior outreach
- 14 • Digital & social media
- 15 • Outbound call, email, and lettering campaigns
- 16 • Annual energy assistance brochure

17  
18 **Q75. In 2024 how many DTE Electric customers received the RIA credit?**

19 A75. Over 132,000 unique electric customers received the RIA credit in 2024 with an  
20 annual monthly average of 73,408. As part of our ongoing cross-functional reporting  
21 process, the monthly counts of customers receiving the RIA credit are shown in  
22 Table 3, with supporting details provided in the Part III by Company Witness Aaron  
23 Willis.

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1

**Table 3                      2022-2024 Electric RIA Customer Counts**

| Year | Jan    | Feb    | Mar    | Apr    | May    | Jun    | Jul    | Aug    | Sep    | Oct    | Nov    | Dec    | Annual Avg |
|------|--------|--------|--------|--------|--------|--------|--------|--------|--------|--------|--------|--------|------------|
| 2022 | 55,273 | 52,472 | 77,861 | 64,098 | 71,279 | 76,710 | 70,158 | 80,906 | 75,554 | 77,992 | 76,119 | 83,522 | 71,829     |
| 2023 | 83,898 | 67,558 | 84,225 | 68,573 | 79,637 | 74,767 | 71,061 | 80,429 | 77,502 | 77,240 | 70,466 | 70,910 | 75,522     |
| 2024 | 77,968 | 69,636 | 71,383 | 80,360 | 81,927 | 70,735 | 81,420 | 76,642 | 64,609 | 72,887 | 57,168 | 69,751 | 72,874     |

2

Note: Customer counts are billing period end of month snapshot and year end variances to Part III reporting fall within 5%.

3

4     **Q76.    How many RIA customers is the Company including in its projected test year?**

5     A76.    In the projected test year, the Company is forecasting the annual RIA credit  
6               enrollment monthly average to be 73,408 customers.

7

8     **Q77.    How did the Company calculate the 73,408 customer projection?**

9     A77.    A three-year historical average of monthly enrollments was used to calculate the  
10               73,408 customers.

11

12    **Q78.    Why did the Company use this method for calculating the forecast?**

13    A78.    In the recent U-21534 Order, the Commission approved an increase in the rates  
14               collected for the RIA credit from 46,428 to 68,085, based on a three-year average of  
15               enrollments. The Company is applying the same methodology for this case filing,  
16               using data from 2022, 2023, and 2024, as the annual average monthly enrollments  
17               have remained relatively stable over this period.

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1 **Q79. Does the Company have any changes in how the RIA credit is applied to eligible**  
2 **customers?**

3 A79. Not in this filing. However, proposed changes to the Company's energy assistance  
4 programs are outlined in the Company's January 29, 2025, report filed in docket U-  
5 20929.

6  
7 Low Income Assistance Credit

8 **Q80. What is the key feature of LIA Credit?**

9 A80. The LIA credit offers qualifying low-income electric customers a \$50 per month  
10 credit on their bill.

11

12 **Q81. What currently makes a customer qualified to receive the LIA credit?**

13 A81. To qualify for this rate an electric customer must have a total household income at  
14 or below 150% FPL.

15

16 **Q82. Is the Company proposing any eligibility changes to the LIA credit?**

17 A82. No.

18

19 **Q83. How many DTE Electric customers are currently enrolled and receiving the**  
20 **electric LIA credit?**

21 A83. Over 37,000 unique households receive the electric LIA credit in 2024 with an  
22 annual monthly average of 30,266. As part of our ongoing cross-functional reporting  
23 process, the monthly counts of customers receiving the LIA credit are shown in  
24 Table 4, with supporting details provided in the Part III by Company Witness Aaron  
25 Willis.

Line  
No.

1

**Table 4                      2022-2024 Electric LIA Customer Counts**

| Year | Jan    | Feb    | Mar    | Apr    | May    | Jun    | Jul    | Aug    | Sep    | Oct    | Nov    | Dec    | Annual<br>Avg |
|------|--------|--------|--------|--------|--------|--------|--------|--------|--------|--------|--------|--------|---------------|
| 2022 | 33,841 | 28,554 | 36,381 | 31,150 | 32,757 | 34,291 | 30,513 | 33,697 | 31,136 | 31,126 | 29,700 | 32,852 | 32,167        |
| 2023 | 32,991 | 28,434 | 35,831 | 29,326 | 34,622 | 32,927 | 30,851 | 35,128 | 34,227 | 32,492 | 28,972 | 29,703 | 32,125        |
| 2024 | 31,582 | 28,739 | 28,946 | 32,238 | 32,429 | 27,804 | 32,024 | 31,936 | 28,319 | 32,766 | 26,210 | 30,203 | 30,266        |

2

Note: Customer counts are billing period end of month snapshot and year end variances to Part III reporting fall within 5%.

3

4

**Q84.    What is the current enrollment process for the LIA credit?**

5

A84.    There are several ways a customer may receive the LIA credit.

6

1.    Customers who become enrolled in the LSP program are also enrolled to receive  
the LIA credit.

7

8

2.    Graduates of LSP may continue to receive the LIA credit if maintaining their  
low-income eligibility status.

9

10

3.    At the Company's discretion, customers receiving the RIA credit can transition  
to LIA when there is availability.

11

12

13

**Q85.    Is the Company requesting any changes to the LIA credit?**

14

A85.    No, we are not.

15

16

LIA transition from D1.6 to D1.11

17

**Q86.    Will customers receiving the LIA credit be on Rate Schedule D1.6?**

18

A86.    No, as per the Order in Case No. U-21534, customers on Rate Schedule D1.6 will  
be transitioning to Rate Schedule D1.11 and will continue to receive the LIA credit  
on that rate.

19

20

Line  
No.

1 **Q87. Will you be providing disconnect information as it pertains to D1.6 customers**  
 2 **transitioning to D1.11 as per the U-21534 Order?**

3 A87. Yes. The Commission directed the Company in the final order of Case No. U-21534  
 4 to "... in its next general rate case, DTE Electric shall include, in relation to the  
 5 transition from Rate Schedule D1.6 to Rate Schedule D1.11, an analysis of shutoff  
 6 information, ...". At the time of this filing, the transition from D1.6 to D1.11 has not  
 7 yet occurred – it will happen later in 2025. However, disconnect rates pre and post  
 8 TOU implementation were analyzed. Pre and post TOU analysis shows very little  
 9 impact to overall disconnect rates (as depicted in Figure 1). Company Witness  
 10 Gerdes's testimony further addresses the ability to shift usage and regression  
 11 analyses. The Company will provide further analysis for D1.6 customers  
 12 transitioning to D1.11 when either a full year of data is available or in the next rate  
 13 case filing (whichever occurs earlier).

14

15 **Figure 1 Comparison of Disconnect Rate Pre and Post Time of Use**

| PRE TOU TRANSITION                    |            |           |                 |
|---------------------------------------|------------|-----------|-----------------|
| DISCONNECTS FOR D1: 04/2022 - 03/2023 |            |           |                 |
|                                       | Disconnect | Count     | Disconnect Rate |
| Low-Income                            | N          | 116,884   | 28.4%           |
|                                       | Y          | 46,258    |                 |
| Non-Low Income                        | N          | 2,131,267 | 3.6%            |
|                                       | Y          | 79,345    |                 |
| TOTAL                                 |            | 2,373,754 | 5.3%            |

| POST TOU TRANSITION                      |            |           |                 |
|------------------------------------------|------------|-----------|-----------------|
| DISCONNECTS FOR D1.11: 04/2023 - 03/2024 |            |           |                 |
| Status                                   | Disconnect | Count     | Disconnect Rate |
| Low-Income                               | N          | 114,850   | 26.7%           |
|                                          | Y          | 41,840    |                 |
| Non-Low Income                           | N          | 2,126,079 | 3.9%            |
|                                          | Y          | 86,023    |                 |
| TOTAL                                    |            | 2,368,792 | 5.4%            |

16

\*low income ≤ 200% FPL

17

18 **Q88. Will DTE communicate to customers transitioning from the D1.6 to D1.11 rate**  
 19 **schedule?**

20 A88. Yes. As part of the conversion from D1.6 to D1.11, the Company will provide  
 21 communication to all impacted customers and will continue to provide access to the

Line  
No.

1 dedicated EAG team for any concerns that customers may have. The Company is  
2 currently developing materials that will provide information on the various low-  
3 income energy efficiency programs and other information for all transitioning  
4 customers.

5

6 Low-Income Credit Card Payments

7 **Q89. Does the Company have any additional concerns that may impact low-income**  
8 **customers ability in paying their bills?**

9 A89. Yes. Per Company Witness Foley’s testimony regarding residential merchant fees,  
10 the Company is concerned that assessing service fees on credit card payments  
11 (instead of socializing those fees through base rates) would create an undue financial  
12 burden on low-income customers. January – December 2024 data shows that 69%  
13 of payments made by low-income customers are done by credit card vs 44% of  
14 payments made by non-low-income customers (see table 5 below). Assessing a  
15 service fee for credit card payments would disproportionately impact low-income  
16 customers, creating additional financial burdens for an already vulnerable  
17 population. These fees could lead to increased financial hardship for households  
18 already struggling to meet their basic needs.

19

20 **Table 5 Credit Card Payments by Low Income/Non-Low-Income**

| Category       | Percentage of payments made by Credit Card |
|----------------|--------------------------------------------|
| Low Income     | 69%                                        |
| Non-Low Income | 44%                                        |



Line  
No.

1    **Uncollectible Expense**

2    **Q90.  What is Uncollectible Expense?**

3    A90.  Uncollectible expense is the income statement impact of the portion of accounts  
4           receivable that is considered uncollectible from customers who used electric service.  
5           Uncollectible expense arises from all sources of billed revenue including revenue  
6           from base rates, surcharges, and PSCR factor.

7  
8    **Q91.  How is uncollectible expense determined?**

9    A91.  Uncollectible expense is determined through a review of arrearage amounts for the  
10          Company and is recorded utilizing historical uncollectible rates as a reserve against  
11          accounts receivables. These receivables include all sources of billed revenue as  
12          noted later in my testimony.

13

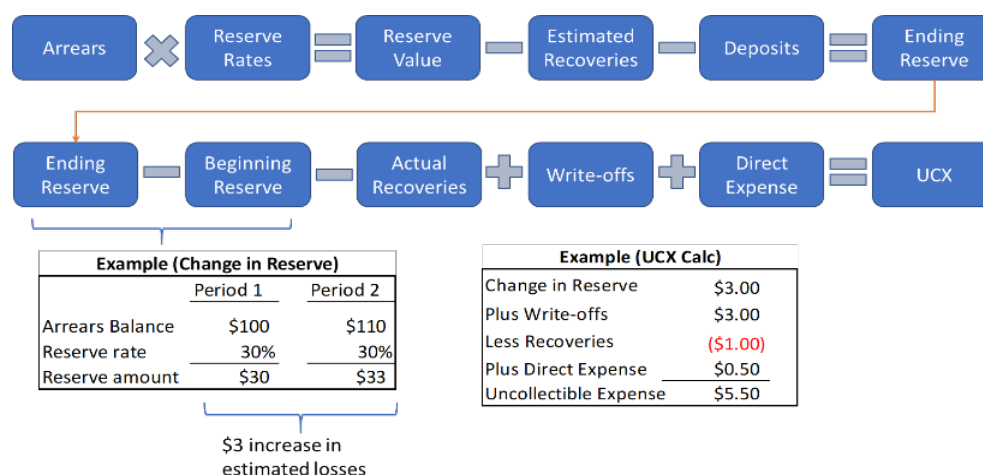
14   **Q92.  How does DTE Electric determine the accounts receivable (AR) reserve for**  
15       **uncollectible accounts?**

16   A92.  DTE Electric uses a balance sheet method. The AR reserve is calculated by applying  
17          reserve factors to aged receivables.  Customer accounts receivable are classified in  
18          30-day increments (arrears buckets) and a reserve factor is applied to each 30-day  
19          increment.  The sum of these reserve values represents the total AR reserve. The  
20          Uncollectible Expense Calculation is shown in Figure 2.

Line  
No.

1

**Figure 2      Uncollectible Expense Calculation**



2      The reserve factors are recalculated monthly using a rolling average of the ratio of  
 3      historical write-offs to historical arrears within each arrears bucket (30, 60, 90, etc.).  
 4      A 12-month rolling average is utilized for residential and small commercial accounts  
 5      and a 60-month rolling average is utilized for large commercial and industrial  
 6      accounts.

7

8      **Q93. How does the Company account for uncollectible expense?**

9      A93. Uncollectible expense is recorded in the income statement to reflect the change in  
 10      the AR reserve. In any given month, this expense is calculated as the  
 11      increase/decrease in the AR reserve, plus accounts that were written-off during the  
 12      month, minus accounts that were recovered (on previously written off accounts)  
 13      during the month. Figure 2 is an illustration of the uncollectible expense calculation  
 14      process.

Line  
No.

1   **Q94. What are the Company's write-off procedures?**

2   A94. Routine customer accounts are generally written off once they age to 150 days past  
3       the final bill due date, which is issued after service is disconnected. Often, however,  
4       there are circumstances that warrant keeping the account on the books until a  
5       resolution is obtained – for example, customers with payment arrangements,  
6       disputes, etc. Once an account is written off, any payments received on that account  
7       are recognized as a recovery. The write-off period of 150 days past the final billing  
8       is generally defined as the latest of either the last effective closed agreement date or  
9       the last bill due date.

10

11   **Q95. What are some of the policies and actions that the Company implements to keep**  
12       **uncollectible expense low?**

13   A95. The Company is aware of our responsibility to keep uncollectible expense costs  
14       down in service of our customers. We strive daily to strike the right balance of  
15       managing uncollectible expense on behalf of all our customers and the impact that  
16       service disconnects have on families.

17

18       In accordance with the Michigan Consumer Standards and Billing Practices, the  
19       Company has policies in place to help mitigate uncollectible expense that includes  
20       noticing, late fees, deposits, returned payment policies and disconnects (for  
21       example). As stated above, the Company also offers many energy assistance options  
22       and other offerings for customers that are having trouble paying their bill.

Line  
No.

1 **Q96. How is uncollectible expense projected in this case?**

2 A96. In this case, the Company is utilizing a historical three-year average (2021-2023) of  
3 the percentage of net write-offs to revenue applied to projected revenue.

4  
5 The revenue utilized in this calculation is inclusive of PSCR Factor and surcharges  
6 that contribute to the Company's uncollectible expense. It is critical to ensure that  
7 all billed revenue components that contribute to uncollectible expense are included  
8 in this calculation to ensure that the company has a means to recover the associated  
9 uncollectible amounts. Without inclusion here, these uncollectible expense amounts  
10 would not be recovered in rates.

11

12 In addition, as per the April 21, 2021, U-2029 Order, uncollectible expense includes  
13 12 months of the proposed 24 months of amortization expense of the Low-Income  
14 Payment Stability Plan Pilot Regulatory Asset that concluded in 2024. This results  
15 in \$48.0 million of uncollectible expense. This amount is calculated on Exhibit A-  
16 13, Schedule C5.8 and shown on line 1, column (h) of that same exhibit.

17

18 **Q97. Is this the same methodology the Company used in its last rate case, Case No.**  
19 **U-21534?**

20 A97. No, while the calculation of a 3-year average of net write-offs to revenue is  
21 unchanged, The Company's calculation of projected billed revenue has changed.  
22 Projected billed revenue is the sum of Total Present Revenue as shown on Exhibit  
23 A-16, Schedule F2, page 2, line 49, column (b). However, that revenue does not  
24 include the Company's forecasted 2026 PSCR Factor revenue, which is a source of  
25 uncollectible expense that has no alternate means of recovery. PSCR Factor revenue

Line  
No.

1 can be calculated using amounts from DTE Electric's 2025 PSCR plan filing U-  
2 21594 as shown on Exhibit A-13, Schedule C5.8, lines 19-21. The PSCR Factor  
3 revenue is the difference between the Company's total forecast power supply cost  
4 and the portion of those costs recovered through base rates; the latter portion is what  
5 is reflected on Exhibit A-16, schedule F2.

6

7 **Q98. In accordance with the Case No. U-21297 Order, is the Company providing a**  
8 **report to the Commission Staff on any debt sale within the past 5 years?**

9 A98. The Company is not providing a report as it has not conducted any debt sales within  
10 the past 5 years.

11

12 **Q99. Does the Company plan to complete a debt sale in the project test year?**

13 A99. No, the Company does not anticipate any debt sale in the projected test year.

14

15 **Cash-Only Payment Process**

16 Q100. Does the Company plan to make any changes to their cash-only payment process as  
17 a result of the Commission's Petition for Rehearing Order in Case No. U-21534  
18 dated April 10, 2025?

19 A100. Yes. Although the Commission determined that the Company is in compliance with  
20 the applicable billing practice rules, the Company plans to adopt the Commission's  
21 suggestions that DTE Electric ensure:

22 1. "That customers subject to the cash-only payment requirement receive both  
23 mail and email notices of imposition of the requirement after it has been  
24 triggered"

Line  
No.

1                   2. “That the notice include information on how the cash-only payment  
2                   requirement may be appealed through the processes available in the billing  
3                   rules”

4

5                   However, the suggestion that the Company ensure “that the notice state that the cash-  
6                   only payment requirement applies only to the person whose payment was returned”,  
7                   will require further analysis and investigation by the Company.

8

9                   Further details on these changes will be developed throughout 2025. DTE Electric  
10                  reserves the right to modify its above-described plans based upon any applicable  
11                  Commission Orders on rehearing in Case No. U-21534 that are issued subsequent  
12                  to the Company’s filing of the instant case.

13

14   **Q101. Does this complete your direct testimony?**

15   A101. Yes, it does.

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. )

## QUALIFICATIONS

## DIRECT TESTIMONY

MICHAEL S. COOPER

**DTE ELECTRIC COMPANY**  
**QUALIFICATIONS AND DIRECT TESTIMONY OF MICHAEL S. COOPER**

Line  
No.

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

2    A1.    My name is Michael S. Cooper. My business address is DTE Energy Company,  
3           One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy  
4           Corporate Services, LLC (DTE LLC), a subsidiary of DTE Energy Company (DTE  
5           Energy).

6  
7   **Q2.    On whose behalf are you testifying?**

8    A2.    I am testifying on behalf of DTE Electric Company (DTE Electric or Company).  
9

10   **Q3.    What is your educational background?**

11   A3.    I received a Bachelor of Business Administration Degree with a major in  
12           accounting and finance from the University of Toledo in 1994. I received a Master  
13           of Arts Degree in educational administration from Michigan State University in  
14           1997.

15  
16   **Q4.    What is your current position and work experience?**

17   A4.    My current position is Head of Total Rewards. I joined DTE LLC full time in 2008  
18           and held positions with increasing responsibility in Human Resources. In 2012, I  
19           became the Manager of Compensation and in 2017 I became the Director of  
20           Compensation, Benefits and Wellness. I assumed my current position in 2024.  
21           Prior to joining DTE LLC, I was employed by Manpower as an on-site Staffing  
22           Program Manager and in other related positions for Visteon Corporation. I was  
23           previously employed at Robert William James & Associates as a recruiter with an  
24           emphasis in accounting and finance related positions.



Line  
No.

1 **Q5. What are your current responsibilities as Head of Total Rewards?**

2 A5. As Head of Total Rewards, I have overall responsibility for the design,  
3 implementation, and administration of DTE Energy's, including DTE Electric's,  
4 compensation, design and administration of employee benefits and time/payroll  
5 administration and processing.

6

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

9 A6. Yes. I have sponsored testimony in the following cases:

10 U-18255 2017 DTE Electric General Rate Case

11 U-18999 2017 DTE Gas General Rate Case

12 U-20162 2018 DTE Electric General Rate Case

13 U-20561 2019 DTE Electric General Rate Case

14 U-20642 2019 DTE Gas General Rate Case

15 U-20836 2022 DTE Electric General Rate Case

16 U-20940 2021 DTE Gas General Rate Case

17 U-21291 2024 DTE Gas General Rate Case

18 U-21297 2023 DTE Electric General Rate Case

Line  
No.

1 **Purpose of Testimony**

2 **Q7. What is the purpose of your testimony?**

3 A7. My testimony will present an overview of certain benefit expenses for DTE Electric  
4 for the 2023 historical test period and the 12 months ended December 31, 2026,  
5 projected test period. Specifically, I will provide support for:

- 6 1. Other post-employment benefits costs (OPEB),
- 7 2. New Hire VEBA costs,
- 8 3. Active Health Care costs,
- 9 4. The costs of certain other employee benefits, and,
- 10 5. The impact on projected Employee Pensions and Benefits expense of the
- 11 Company's 2024 Voluntary Separation Incentive Program (VSIP). While
- 12 Company Witness Leslie sponsors the overall impact on the Company's
- 13 expense of VSIP, I am sponsoring the allocation of these savings to the
- 14 individual expense components.

15 In summary, my testimony will support the reasonableness and validity of the  
16 projected employee benefits expense to be incurred by DTE Electric for the  
17 projected test period.

18

19 **Q8. Are you sponsoring any exhibits in this proceeding?**

20 A8. Yes. I am sponsoring in whole, or in part, the following exhibits:

| 21 | <u>Exhibit</u> | <u>Schedule</u> | <u>Description</u>                               |
|----|----------------|-----------------|--------------------------------------------------|
| 22 | A-13           | C5.11           | Projected Operation and Maintenance Expenses -   |
| 23 |                |                 | Employee Pensions and Benefits Expense           |
| 24 | A-13           | C5.11.1         | Willis Towers Watson Healthcare Trend Projection |
| 25 | A-13           | C5.11.2         | PwC 2025 Medical Cost Trend                      |

Line  
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|   |      |         |                                                |
|---|------|---------|------------------------------------------------|
| 1 | A-13 | C5.11.3 | Self-Insured Medical Expense Normalization     |
| 2 |      |         | Adjustment                                     |
| 3 | A-13 | C5.12.2 | Projected Operation and Maintenance Expenses - |
| 4 |      |         | Other Post-Employment Benefits (OPEB)          |

5

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

7 A9. Yes, they were. Portions of Exhibit A-13, Schedule C5.11 are sponsored by

8 Company Witnesses Fix and Uzenski.

9

10 **EMPLOYEE PENSIONS AND BENEFITS**

11 **Q10. What is reflected on Exhibit A-13, Schedule C5.11?**

12 A10. Exhibit A-13, Schedule C5.11 reflects the Company's projected Employee

13 Pensions and Benefits expense for the projected test year. This exhibit is sponsored

14 jointly with Company Witnesses Fix and Uzenski. Page one is a recap of the

15 Company's Employee Pensions and Benefits expense for both the historical test

16 year, in column (b), and the projected test year, in column (d). Page two of this

17 exhibit provides the components of the required adjustments to the historical test

18 year to develop the Company's Employee Pensions and Benefits expense for the

19 projected test year. Specifically, Known and Measurable adjustments are reflected

20 in columns (c) through (e) to develop the Adjusted Historical Test Period expense

21 levels in column (f). The Adjusted Historical Test Period expense is further

22 adjusted for expected escalations or specific projections, as reflected in columns (g)

23 through (k) to produce the Employee Pensions and Benefits expense for the

24 projected test year, as reflected in column (l). The expected impact of the VSIP is

Line  
No.

1 reflected in column (m) and the total projected Employee Pensions and Benefits  
2 expense is reflected in column (n).

3

4 **Q11. What are the Known and Measurable adjustments?**

5 A11. Exhibit A-13, Schedule C5.11 reflects two categories of Known and Measurable  
6 adjustments that relate to 1) Temporary items, and 2) Normalization Adjustments.

7

8 **Q12. Why is it appropriate to adjust the Company's historical Employee Benefits**  
9 **expense for the Temporary items?**

10 A12. As a result of the financial challenges that confronted the Company in 2023, the  
11 Company implemented a number of temporary cost reduction initiatives as  
12 discussed by Company Witness Bruzzano. In addition, certain costs or credits were  
13 recognized in 2023 that are non-recurring. The Temporary adjustments reflect  
14 these items, which will be explained in the discussion of the individual cost  
15 components.

16

17 **Q13. What is reflected in Normalization Adjustments?**

18 A13. Normalization Adjustments category includes specific adjustments to certain cost  
19 components to address the impact of unusual expenses recognized in 2023 that need  
20 to be eliminated to produce a recurring level of Employee Benefits prior to any  
21 escalations through the end of the projected test year. The specific adjustments will  
22 be explained in the discussion of the individual cost components.

Line  
No.

1 **OTHER POST-EMPLOYMENT BENEFITS (OPEB) COSTS**

2 **Q14. What are OPEB Costs?**

3 A14. OPEB costs relate to the provision of retiree medical, dental, prescription drug and  
4 life insurance benefits. OPEB is a cost recognized under U.S. GAAP Accounting  
5 Standard Codification (ASC) section 715-60. Similar to ASC 715-30, as explained  
6 by Witness Fix, OPEB costs are determined under ASC 715-60 at the beginning of  
7 each fiscal year.

8  
9 **Q15. What are the cost components of OPEB?**

10 A15. OPEB has the same basic cost components as pension costs, as described by  
11 Witness Fix. They are:

12 Service Costs: Service Costs are the portion of the expected post-retirement benefit  
13 obligation, on a present value basis, attributable to employee participation service  
14 during the current period. Service Costs reflect actuarial assumptions of employee  
15 turnover, age at retirement, and expected longevity. Service Costs also depend on  
16 the estimated costs of providing these benefits after the employee's retirement and,  
17 therefore, is impacted by both current medical cost levels and expected medical  
18 cost inflation.

19  
20 Interest Costs: Interest Costs are the costs arising from the current period interest  
21 on the discounted Accumulated Post-Retirement Benefit Obligation (APBO). The  
22 APBO was discounted to today's dollars based on a discount rate of 5.19% as of  
23 December 31, 2022, which was also used to determine Interest Costs in 2023. The  
24 discount rate used to measure the APBO as of December 31, 2023, was 5.00%,  
25 which was also used to determine the Interest Costs on the APBO during the

Line  
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1 projected test year. The discount rate of 5.00% was determined based on the  
2 interest rate environment at the end of 2023, as determined in a similar manner to  
3 the measurement of the Company's pension costs, as described by Witness Fix.

4  
5 Expected Return on Assets: The Expected Return on Assets (ERoA), which is an  
6 offset to OPEB costs, based on the forward-looking long-term financial market  
7 expectations to avoid large swings in OPEB costs based on short-term investment  
8 performance. The ERoA was 7.20% during the historical test year and is 7.60%,  
9 7.70% and 7.60% in 2024, 2025, and 2026, respectively. These assumptions are  
10 based on market conditions and funded status at the end of 2023 and projected  
11 changes in funded status.

12  
13 Amortizations: This cost component includes the amortizations related to deferred  
14 Gains and Losses as well as Prior Service Costs. Accumulated gains and losses,  
15 outside the 10% corridor, as described for pension costs by Witness Fix, are  
16 amortized over the current estimated remaining service life of active participants.  
17 Prior Service Costs are amortized over the estimated remaining service life of  
18 active participants, at the time of the last plan change, to the age at which these  
19 employees are fully eligible for the benefits.

20  
21 **Q16. How are these OPEB costs expected to change between the historical test year**  
22 **and the projected test year?**

23 A16. As reflected on Exhibit A-13, Schedule C5.12.2, the Company's OPEB costs are  
24 projected to decrease from negative \$24.168 million in the historical test year to  
25 negative \$21.971 million during the projected test year. After adjustments for the

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1 portion of OPEB costs transferred and capitalized, the net OPEB expense is  
2 projected to be negative \$12.954 million, as shown on Exhibit A-13, Schedule  
3 C5.12.2, line 17.

4

5 **Q17. Is the negative OPEB expense included in the Company's proposed revenue**  
6 **requirement?**

7 A17. No. Witness Uzenski sponsors the Company's proposal to continue to defer to the  
8 projected negative OPEB expense to the accumulated regulatory liability. Thus,  
9 the projected OPEB expense is not reflected in the Company's proposed revenue  
10 requirement and the negative OPEB expense is eliminated on line 18 of Exhibit A-  
11 13, Schedule C5.12.2.

12

13 **Q18. Is the Company amortizing the OPEB regulatory liability?**

14 A18. Yes. In its Order in Case No. U-21297, the Commission adopted a seven-year  
15 amortization of the Company's OPEB regulatory liability as of December 31, 2022,  
16 which resulted in an annual amortization of \$18.300 million that reduced the  
17 Company's revenue requirement (Case No. U-21297, December 1, 2023, Order, pp  
18 223-224). The revenue requirement adopted by the Commission in its Order in  
19 Case No. U-21534 reflected the continued amortization of the OPEB regulatory  
20 liability (Case No. U-21534, January 23, 2025). This annual amortization of  
21 \$18.300 million is reflected on Exhibit A-13, Schedule C5.12.2, line 19, as a  
22 reduction to OPEB expense and is also reflected on Exhibit A-13, Schedule C5.11,  
23 line 3.

Line  
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1 **Q19. Has DTE Electric previously externally funded its OPEB costs?**

2 A19. Yes. DTE Electric has generally funded the OPEB costs included in the Company's  
3 revenue requirement adopted by the Commission in previous orders through a  
4 Voluntary Employees' Beneficiary Association (VEBA) trust and an Internal  
5 Revenue Code Section 401(h) trust.

6

7 **Q20. Will the Company externally fund its OPEB liability in the future?**

8 A20. No. Since the Commission approved the Company's proposal in Case No. U-21534  
9 to continue the deferral of the projected negative OPEB expense, initially approved  
10 by the Commission in Case No. U-17767, the Company's current and projected  
11 revenue requirements do not include any OPEB expense, other than the  
12 amortization of the OPEB regulatory liability, and as a result there is no obligation  
13 for the Company to externally fund its OPEB liability.

14

15 **NEW HIRE VEBA COSTS**

16 **Q21. What is the New Hire VEBA?**

17 A21. The New Hire VEBA expense on Exhibit A-13, Schedule C5.11, line 4 reflects the  
18 costs of the plans that are offered in lieu of the traditional retiree healthcare plan  
19 for eligible employees, as adjusted for the portion of those costs that are capitalized.  
20 Because the New Hire VEBA is generally offered in lieu of the Company's  
21 traditional retiree healthcare plan, which is closed to new participants, this increase  
22 in costs is offset by avoided OPEB costs.



Line  
No.

1 **Q22. What are the components of the Company's New Hire VEBA costs?**

2 A22. The Company's New Hire VEBA costs consist of contributions generally made for  
3 newly hired employees after 2012. Specifically, the Company contributes \$4,000  
4 on behalf of non-represented and Local 17 employees in their year of hire, as  
5 prorated for month of hire, and \$4,000 every year thereafter. For employees  
6 represented by Local 223, the Company makes a payment of \$1,650 on their first  
7 service anniversary and contributes \$40 per week thereafter. In 2023 the average  
8 Company contribution for Local 223 employees was \$2,172.

9

10 In addition, the Company recognizes a true-up of the estimate of the Company's  
11 liability for contributions for non-represented and Local 17 employees that reflects  
12 final determinations of plan eligibility and any forfeitures by employees that leave  
13 the Company before the end of the 10-year vesting period. No such true-up is  
14 required for Local 223 employees because payments are made through the bi-  
15 weekly payroll process, and the Company doesn't receive any benefit from  
16 employee departures.

17

18 **Q23. What are the Known and Measurable adjustments you are proposing to the**  
19 **Company's 2023 New Hire VEBA expense?**

20 A23. As reflected on page 2 of Exhibit A-13, Schedule C5.11, line 4, I am proposing the  
21 normalization for the impact of unusually high true-ups recognized in 2023, as  
22 described below.

Line  
No.

1   **Q24. Why is a Known and Measurable normalization adjustment required for the**  
2       **Company's recorded 2023 New Hire VEBA expense reflected on Exhibit A-13,**  
3       **Schedule C5.11, page 2, line 4, column (d)?**

4   A24. In 2023, the Company recognized an unusually high true-up adjustment related to  
5       the New Hire VEBA costs recognized in 2022 compared to the actual funding  
6       requirement for 2022. Specifically, the 2022 true-up reflected as a reduction to the  
7       Company's 2023 New Hire VEBA costs was \$2.920 million, whereas the average  
8       of the five prior years true-up adjustments was only \$0.439 million. Accordingly,  
9       the Company's 2023 costs were thus understated by the difference between the  
10      2023 actual and the five-year average of \$2.481 million, which after reduction for  
11      the proportion of costs capitalized in 2023 of 44.6%, understated the Company's  
12      expense by \$1.375 million.

13

14   **Q25. Why was the true-up for 2022 recognized in 2023 unusually high?**

15   A25. The unusually high true-up for 2022 represents a continued impact of the disruption  
16      in the Company's workforce as a result of the COVID-19 pandemic. First, due to  
17      historically low levels of employee turnover during the COVID-19 pandemic in  
18      2020 and 2021, there was a reduction in the number of new hires eligible to  
19      participate in the plan in 2021. Second, as the economy transitioned out of the  
20      pandemic, employee turnover increased and there was a substantial increase in the  
21      forfeitures of accumulated balances by employees that left the Company before  
22      they were vested in the plan. These two factors resulted in an unusually large true-  
23      up for 2022 that was recognized in 2023. Accordingly, the Company's 2023  
24      recorded New Hire VEBA expense should be increased by \$1.375 million.

Line  
No.

1 **Q26. What is the basis for the projected increase in the New Hire VEBA expense?**

2 A26. The New Hire VEBA expense is projected to increase from the adjusted 2023  
3 expense of \$6.781 million to \$8.086 million in the projected test year, before  
4 recognition of the impact of VSIP. This increase reflects the growth in the number  
5 of plan participants due to new hires.

6

7 **Q27. How was the projected New Hire VEBA expense developed?**

8 A27. The projected New Hire VEBA expense was developed based on the number of  
9 active participants in the plans as of December 31, 2023, which was increased by  
10 the number of expected new participants based on the most recent five-year average  
11 of actual new plan participants prorated for the assumption that the new participants  
12 would be added evenly throughout the year (i.e., divided by two). The average plan  
13 participants for each year were costed out based on the Company's required  
14 contributions for each plan, as described above, to determine the projected gross  
15 cost for each plan. The amount for the non-represented employees and employees  
16 represented by Local 17 was then reduced by the five-year average of employee  
17 forfeitures for those plan participants that left the Company before they were vested  
18 in the plan. Total costs for the projected test year are \$14.587 million, which is  
19 reduced by 44.6% to recognize the portion of costs to be capitalized, resulting in  
20 net New Hire VEBA expense of \$8.086 million. This represents an average annual  
21 increase in the New Hire VEBA expense of 6.1% based on the 2023 normalized  
22 expense.

Line  
No.

1 **ACTIVE HEALTHCARE EXPENSE**

2 **Q28. What are the healthcare benefit programs offered to active employees?**

3 A28. The Company offers a competitive active healthcare benefits package for the  
4 attraction and retention of a skilled workforce. The components of these benefits  
5 are summarized on Exhibit A-13, Schedule C5.11 (lines 8 through 10) and consists  
6 of medical, dental, and vision benefits for active employees that are projected to  
7 increase from \$43.241 million in the historic test year to \$51.951 million during the  
8 projected test year, before the impact of the VSIP. This increase includes two  
9 Known and Measurable adjustments of the Company's 2023 Active Healthcare  
10 costs and annual escalations for the adjusted medical plan trend of 4.67% in 2024,  
11 4.16% in 2025, and 3.59% in 2026, as more fully described below in Q38 through  
12 Q41. The annual escalations for dental and vision costs are 2.94% in 2024, 2.85%  
13 in 2025, and 3.39% in 2026, based on projected increases in the Consumer Price  
14 Index.

15

16 **Q29. What are the Known and Measurable adjustments to the Company's 2023**  
17 **Active Healthcare costs?**

18 A29. As reflected on page 2 of Exhibit A-13, Schedule C5.11, columns (c) and (d), I  
19 make two Known and Measurable Adjustments. The first Known and Measurable  
20 adjustment is for two One-Time items as reflected in column (c), which relates to a  
21 one-time credit from its Pharmacy Benefit Manager (PBM) and the elimination of  
22 COVID-19 related medical services that were discontinued by the Company in  
23 early 2023 that are not expected to recur. The Company's total credit from the  
24 PBM was \$1.135 million and the COVID-19 costs were \$293,000. The net impact  
25 on the Company's costs of the elimination of these one-time costs is an increase of

Line  
No.

1 \$842,000. Based on the 2023 capitalization percentage of 46.6%, this resulted in a  
2 one-time reduction to Medical expenses of \$450,000, which is reflected as an  
3 increase to expense on line 8, column (c). The second Known and Measurable  
4 adjustment, as reflected in column (d) includes an adjustment to normalize the  
5 Company's Medical expenses related to its self-insured medical costs it incurs for  
6 employee and their dependents, which increases Medical expenses by \$2.409  
7 million, as reflected on line 8, column (d). This adjustment will be explained in  
8 more detail below.

9

10 **Q30. Why is it necessary to normalize the Company's self-insured medical costs?**

11 A30. The year-to-year volatility of actual Active Healthcare costs makes the use of any  
12 one historical period's cost a potentially unreliable starting point in the  
13 determination of projected Active Healthcare costs. Accordingly, it is necessary to  
14 normalize the Company's 2023 self-insured medical costs to reflect this volatility.

15

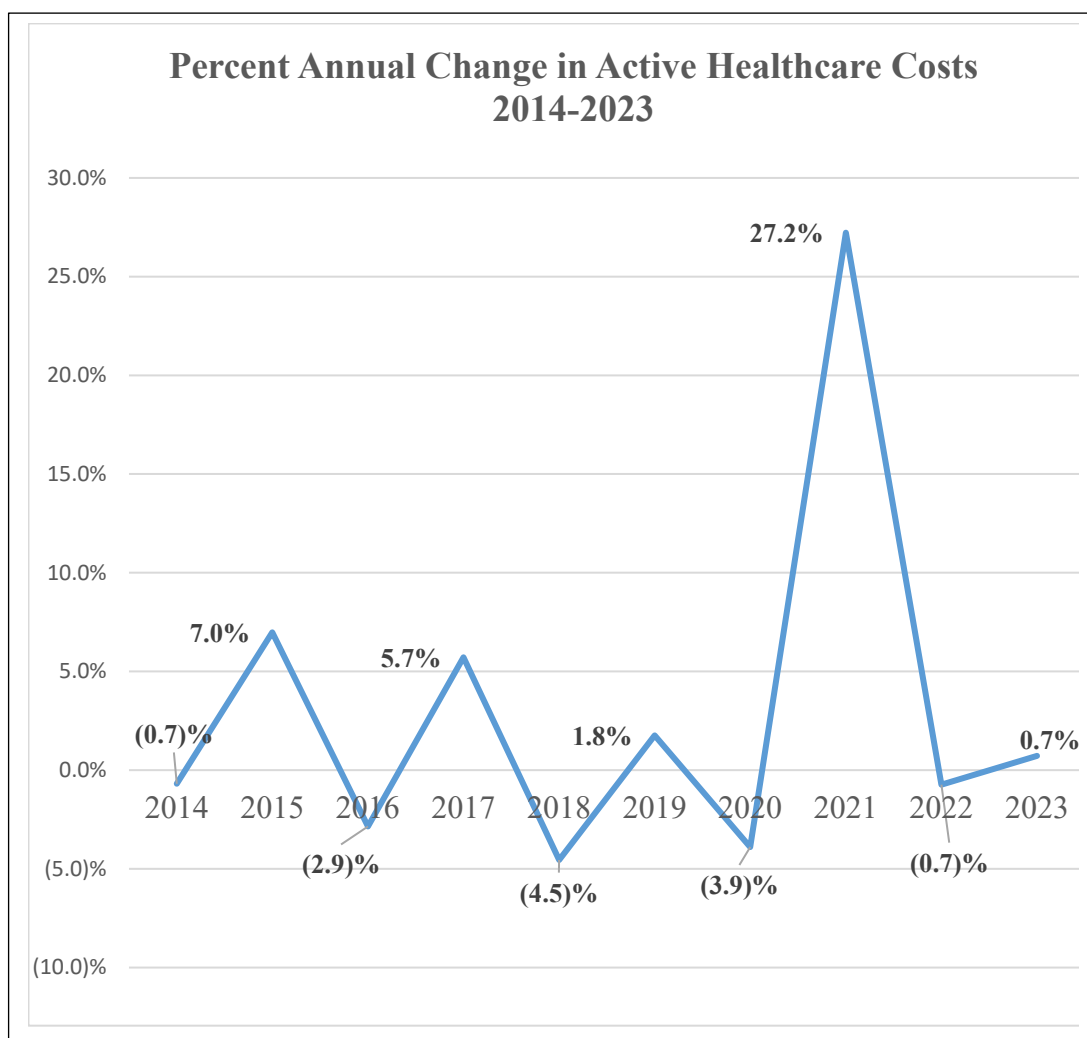
16 **Q31. What is the basis for your conclusion that year-to-year Active Healthcare costs**  
17 **are volatile?**

18 A31. The volatility in the Company's Active Healthcare costs is reflected in Table 1  
19 below and reflects Active Healthcare costs per employee for the years 2014 through  
20 2023, as adjusted for one-time credits in 2018 related to Self-Insured medical and  
21 in 2023 related to the Company's Pharmacy Benefit Manager.

Line  
No.

1

Table 1



2

3 This chart shows that the Company's actual Active Healthcare costs have changed  
4 relative to the prior year by as much as 27.2% in 2021 to a decrease of 4.5% in  
5 2018, demonstrating that Active Healthcare costs can vary significantly from year-  
6 to-year. While the average percent change in the Company's Active Healthcare  
7 costs for the years 2014 through 2023 was 3.4%, the standard deviation of this  
8 average was 9.8%. This high standard deviation means that for about 68% of the  
9 years, the Company's annual change in Active Healthcare costs could range from

Line  
No.

1 negative 6.4% to a positive 13.2% and highlights that the historical average is a  
2 poor predictor of likely future results.

3

4 **Q32. What is the cause of this volatility?**

5 A32. The primary reason the Company's Active Healthcare costs reflect substantial  
6 volatility among years is that the Company is self-insured for almost 70% of its  
7 total Active Healthcare costs. Self-insurance results in the level of Active  
8 Healthcare costs incurred by the Company being highly impacted by the mix and  
9 severity of medical treatments administered to employees and their eligible  
10 dependents in any given year. Moreover, the small sample size of the experience  
11 of the Company makes it a poor predictor of future experience. In 2023, the  
12 Company had about 3,800 employees enrolled in its self-insured medical plans,  
13 which inclusive of dependents, represented about 9,800 total participants. The total  
14 number of participants represents too small of a sample to infer that the experience  
15 over a few years will reflect the long-term trends in the Company's Active  
16 Healthcare costs. Indeed, WTW specifically identifies that historical trends for any  
17 specific company are not the best predictor of future trends (Exhibit A-13, Schedule  
18 C5.11.1, p. 4). This small sample size is a key contributor to the year-to-year  
19 variability as reflected in the high standard deviation relative to the average, as  
20 discussed above.

21

22 **Q33. Did the Commission address this point in its Order in Case No. U-21534?**

23 A33. Yes. The Commission stated that it "finds that evaluating the actual expenses and  
24 year-to-year changes experienced by the entire pool of employees provides a more  
25 reliable indication of future expenses than national trend data. The company's

Line  
No.

1 presentation of its range of year-to-year changes substantiates this point.” (Case  
2 No. U-21534, Order, January 23, 2025, p. 257)

3

4 **Q34. Do you agree with the Commission’s conclusion?**

5 A34. No. First, the Commission’s reference to the “entire pool of employees” fails to  
6 distinguish the difference between the employees covered by fully insured  
7 healthcare plans, such as Health Maintenance Organizations (HMOs), which have  
8 relatively less annual volatility, and the Company’s self-insured healthcare plans.  
9 As explained in more detail below, it is the self-insured healthcare plans that create  
10 the high variability in the Company’s Active Healthcare costs between years.  
11 Indeed, in the years 2019 through 2023, the changes in the costs of the Company’s  
12 self-insured healthcare plans have, on average, accounted for 144% of the average  
13 annual change in the Company’s total Active Healthcare costs. Second, the  
14 Commission’s reference to the historical volatility in the Company’s Active  
15 Healthcare costs corroborates the importance of the use of a national trend  
16 projection rather than the Company’s historical experience, because of the high  
17 volatility in the annual change in the Company’s Active Healthcare costs, as  
18 reflected in Table 1.

19

20 **Q35. What are the primary contributors to the volatility in Active Healthcare costs?**

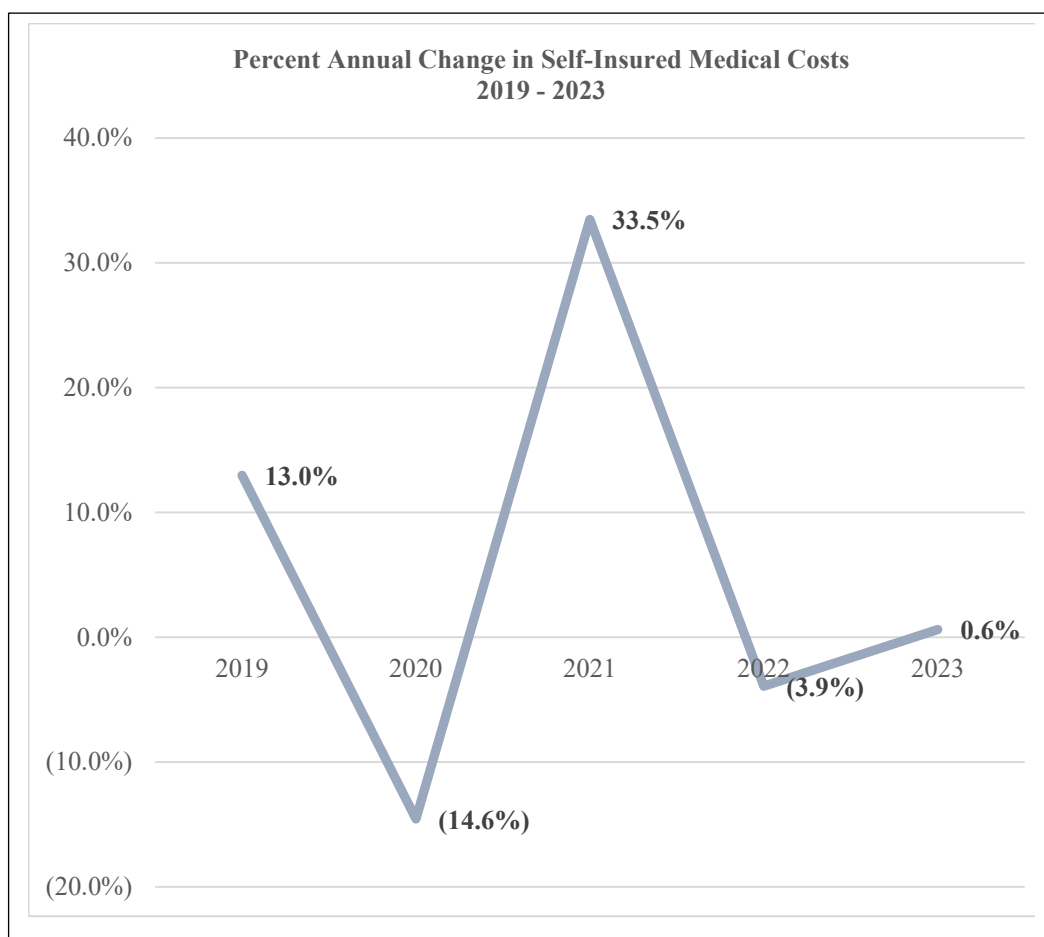
21 A35. Self-insured medical costs represent the single largest component of the Company’s  
22 total Active Healthcare costs. This component also represents the largest  
23 contributors to the annual volatility in the Company’s total Active Healthcare costs.  
24 The annual percent change for self-insured medical and prescription drugs is  
25 reflected in Table 2 below.



Line  
No.

1

Table 2



2

3 **Q36. In light of the volatility in self-insured medical costs, how do you propose to**  
4 **normalize the Company's historical Active Healthcare costs to eliminate an**  
5 **unrepresentative starting point in determining Active Healthcare costs for the**  
6 **projected test year?**

7 A36. Because the cost of self-insured medical is dependent on usage in any given year,  
8 which can vary significantly between years, and unit costs, which tend to increase  
9 each year, the best way to normalize a specific year's costs is to create an average  
10 of historical usage and price that usage out at the unit costs for the latest year. This

Line  
No.

1 results in a normalized annual cost that is not distorted by the level of usage in the  
2 historical test year.

3

4 **Q37. Have you performed such a calculation?**

5 A37. Yes. Exhibit A-13, Schedule C5.11.3 page 2 reflects both the number of medical  
6 services provided and the costs of these services for the ten largest cost medical  
7 categories for both DTE Electric and DTE LLC, in recognition that a portion of  
8 DTE LLC Active Healthcare costs are allocated to DTE Electric. The information  
9 for DTE Electric is reflected on lines 2 through 20 and the information for DTE  
10 LLC is reflected on lines 23 through 41. The actual number of medical services  
11 provided for each of the years 2018 through 2023 are reflected in columns (b)  
12 through (g). The five-year average of those medical services for the years 2018  
13 through 2022 is reflected in column (h) and column (i) shows how much the five-  
14 year average of medical services is more or less than the number of medical services  
15 delivered in 2023. This difference is priced out by the actual average costs of each  
16 of these services delivered in 2023, as reflected in column (p). This measures the  
17 extent to which the priced out self-insured medical services in 2023 were more or  
18 less than the five-year average, which results in an increase of \$3.473 million for  
19 DTE Electric and \$1.287 million for DTE LLC, as reflected in column (q). Since  
20 the cost of medical services are based on reports from the Company's self-insured  
21 provider, which can reflect lags in reporting or subsequent adjustments, the total  
22 cost of self-insured claims doesn't exactly match the cost of the self-insured claims  
23 recognized by the Company. Accordingly, the Adjusted Normalization amounts  
24 reflected in column (r) prorates the minor difference between the recorded and

Line  
No.

1 reported claims. The result is an increase in the 2023 self-insured medical services  
2 of \$3.563 million for DTE Electric and \$1.274 million for DTE LLC.

3

4 Exhibit A-13, C5.11.3, page 1 reflects a recap of the information on page 2, which  
5 shows that DTE Electric's total costs increase of \$4.512 million (\$3.563 million for  
6 DTE Electric and \$0.948 million for DTE LLC costs allocated to DTE Electric).  
7 After reduction for the proportion capitalized (46.6%) the Company's 2023 Active  
8 Healthcare expense is increased by \$2.409 million.

9

10 **Q38. Would it be reasonable to use the Company's actual 2023 self-insured medical**  
11 **costs as the basis for projecting the Company's future Active Healthcare**  
12 **costs?**

13 A38. No. As is apparent from Exhibit A-13, Schedule C5.11.3 page 2, the level and costs  
14 of medical services vary substantially over the five years. For example, the  
15 Company's Facility Inpatient Surgical (line 4) and Facility Outpatient Specialty  
16 Drugs (line 11) costs were substantially lower in 2023 compared to prior years  
17 because of a reduction in the number of medical services delivered in 2023. The  
18 use of the actual 2023 self-insured medical services costs essentially presumes that  
19 the Company's experience in 2023 is representative of the level of activity that will  
20 repeat in each successive year. The high variability of the level of activity in the  
21 years 2018 through 2023 demonstrates that this is an erroneous presumption.

Line  
No.

1   **Q39. How has the Commission traditionally addressed cost elements that are**  
2       **subject to volatility?**

3   A39. In the case of uncollectible expense, the Commission has routinely adopted the  
4       prior year's average of the ratio of uncollectibles to revenues to project the  
5       Company's future uncollectible expense, and similarly for DTE Gas, has used an  
6       average of historical Lost and Unaccounted for Gas volumes to project future Lost  
7       and Unaccounted for Gas expense. In those instances, the pricing is separated from  
8       the level of activity because the ratios of uncollectibles and the volumes of Lost  
9       and Unaccounted for Gas were determined first, and then those ratios are priced by  
10      applying the percentage of historical uncollectibles to current revenue or the  
11      average Lost and Unaccounted for Gas volumes are multiplied by the projected cost  
12      of gas rate.

13

14      The normalization adjustment for self-insured medical services uses a similar  
15      approach because it measures average levels of activity and prices those services  
16      out at 2023 costs.

17

18   **Q40. What is the basis for your future trend factor in active healthcare costs used**  
19       **for the projected periods in this proceeding?**

20   A40. The annual Active Healthcare costs annual escalations of 4.55% for 2024, 4.05%  
21       for 2025, and 3.56% for 2026, are based on the average escalation for the major  
22       cost components within Active Healthcare, as reflected in Table 3 below.

Line  
No.

1

Table 3

| <u>Description</u>         | <u>2024</u> | <u>2025</u> | <u>2026</u> | <u>Three-<br/>Year<br/>Average</u> | <u>Proportion<br/>of 2023<br/>Costs</u> |
|----------------------------|-------------|-------------|-------------|------------------------------------|-----------------------------------------|
| Self-Insured Medical       |             |             |             |                                    |                                         |
| Medical                    | 4.00%       | 3.50%       | 2.80%       | 3.43%                              | 39.2%                                   |
| Medical Drugs              | 7.50%       | 7.00%       | 6.50%       | 7.00%                              | 4.9%                                    |
| Total Self-Insured Medical | 4.44%       | 3.78%       | 3.00%       | 3.74%                              | 44.1%                                   |
| Self-Insured Drugs         | 7.50%       | 7.00%       | 6.50%       | 7.00%                              | 14.8%                                   |
| HMOs                       | 3.74%       | 3.74%       | 3.74%       | 3.74%                              | 34.7%                                   |
| Other                      | 2.94%       | 2.85%       | 3.39%       | 3.06%                              | (0.9%)                                  |
| Total Medical              | 4.67%       | 4.15%       | 3.59%       | 4.13%                              | 92.7%                                   |
| Dental                     | 2.94%       | 2.85%       | 3.39%       | 3.06%                              | 6.8%                                    |
| Vision                     | 2.94%       | 2.85%       | 3.39%       | 3.06%                              | 0.6%                                    |
| Total                      | 4.55%       | 4.05%       | 3.56%       | 4.05%                              | 100.0%                                  |

2

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14

The escalations for the Self-Insured Medical cost category are based on projections for healthcare trends provided by the healthcare experts at Willis Towers Watson (WTW). As reflected on page 7 of Exhibit A-13, Schedule C5.11.1, WTW projects trends for Medical costs of 6.50% in both 2024 and 2025 and 6.30% in 2026. WTW projects trends for Prescription Drugs of 10.00% for 2024, 2025 and 2026. These unadjusted trend factors are reduced by 2.50% in 2024, 3.00% in 2025, and 3.50% in 2026 to reflect the expected savings to be realized by the Company's Wellness program. This results in Medical escalations of 4.00% in 2024, 3.50% in 2025, and 2.80% in 2026 and Prescription Drugs escalation of 7.50% in 2024, 7.00% in 2025 and 6.50% in 2026. For Prescription Drugs costs delivered by the Company's Pharmacy Benefit Manager, the escalations are the same as used for the Self-Insured Medical drug costs. The costs for the Company's Health Maintenance

Line  
No.

1 Organizations, or HMOs, are escalated annually at the three-year average escalation  
2 for the Self-Insured provider of 3.80%. All other cost categories are escalated at  
3 the level of overall inflation as measured by the Consumers Price Index, provided  
4 by Company Witness Uzenski, of 2.94% for 2024, 2.85% for 2025 and 3.39% for  
5 2026.

6

7 **Q41. How were the WTW trend factors determined?**

8 A41. WTW's first step is to develop the Allowed Trend, which is based on its internal  
9 guidance and represents its consensus expectation for medical and prescription drug  
10 costs. WTW developed the Allowed Trend based on its internal book of business  
11 and national surveys as well as data from United States government offices and  
12 agencies, and various third-party sources, as described on page four of Exhibit A-  
13 13, Schedule C5.11.1. The Allowed Trend is adjusted specifically for the  
14 Company's average fixed plan design leveraging to develop the future Medical Plan  
15 Trend, which is the basis of the Company's projected active healthcare costs.

16

17 **Q42. What assumptions are reflected in WTW's overall trend factors?**

18 A42. WTW's key assumptions for 2024 are described on page five of Exhibit A-13,  
19 Schedule C5.11.1. Specifically, WTW assumes that overall inflation will be  
20 between 2.00% and 3.50%. Added to the overall inflation is the incremental  
21 healthcare inflation of between 2.25% and 4.00%, which is premised on the  
22 assumption that healthcare inflation will likely revert to the historical pattern of  
23 healthcare inflation exceeding overall inflation. This assumption reflects the  
24 expectation that labor shortages in the healthcare industry will become more acute  
25 as well as the likelihood of increased pricing for long-term contracts between

Line  
No.

1 insurance carriers and healthcare providers. Finally, WTW expects the impact of  
2 higher utilization will add between 1.75% and 3.50% to the expected trend factors.  
3 In sum, WTW expects the overall medical trend in 2024 will increase between  
4 6.00% and 11.00%.

5  
6 **Q43. Are you aware of any corroborating sources that support the reasonableness**  
7 **of WTW's projections?**

8 A43. Yes. A study released in 2024 by PwC's Health Research Institute, as reflected in  
9 Exhibit A-13, Schedule C5.11.2, projects that medical costs will increase by 7.5%  
10 in 2024 and 8.0% in 2025. This study supports the reasonableness of the healthcare  
11 trend projections provided by WTW.

12

13 **OTHER EMPLOYEE BENEFITS COSTS**

14 **Q44. What are Other Benefits Costs?**

15 A44. The costs of the Company's Other Employee Benefits are also reflected on Exhibit  
16 A-13, Schedule C5.11 (lines 13 through 24). These costs include a variety of other  
17 benefits including Accrued Vacation, Wellness Program, Life Insurance, Long-  
18 Term Disability, fees associated with the Affordable Care Act (ACA), General  
19 Benefit, and Benefit Plan Administration Fees. The remaining Other Benefits  
20 Costs are described by Witness Fix. In total, these expenses are projected to  
21 increase from \$12.933 million in the historic test year to \$15.923 million in the  
22 projected test year, before the impact of the VSIP, as shown on line 25, column (l)  
23 of Exhibit A-13, Schedule C5.11, page 2.

Line  
No.

1 **Q45. What adjustments are you proposing to Accrued Vacation expense?**

2 A45. As reflected on page 2 of Exhibit A-13, Schedule C5.11, line 13, I am proposing  
3 two adjustments to Accrued Vacation expense. The first, which is reflected on  
4 column (d), represents a normalization of the Company's recorded 2023 accrued  
5 Vacation expense and the second, which is reflected in column (k), represents the  
6 projection of this expense through the end of the projected test year.

7  
8 **Q46. What is the Normalization of the Company's Accrued Vacation expense?**

9 A46. Accrued Vacation expense can vary from year to year based on the timing of the  
10 vacation earned and usage of vacation time by employees, as well as forfeitures.  
11 This volatility in annual accrued vacation expense has been traditionally addressed  
12 using a five-year average of the annual expense. Accordingly, the adjustment to  
13 Vacation Accrual expense reflected on page 2 of Exhibit A-13, Schedule C5.11,  
14 line 13, column (d), is based on the average of the recorded expense for the years  
15 2019 through 2023 of negative \$588,000. This results in a decrease to Accrued  
16 Vacation expense of \$390,000.

17  
18 **Q47. What is the basis for your projection of the Company's Accrued Vacation**  
19 **expense?**

20 A47. The adjusted five-year average is escalated by the projected annual pay increases  
21 of 3.5% in 2024 and 3.0% in 2025 and 2026, which results in Accrued Vacation  
22 expense of negative \$645,000.



Line  
No.

1   **Q48. How did you project the increase in the Company's Wellness Program**  
2       **expense?**

3   A48. As referenced in my discussion of Active Healthcare expense, the Company has a  
4       Wellness Program designed to produce significant reductions in future Active  
5       Healthcare expense. Before the development of projected Wellness Program  
6       expense, I first have to make a Known and Measurable adjustment related to a  
7       temporary reduction. This temporary reduction of the Wellness Program expenses  
8       in 2023 of \$2.270 million was taken to mitigate the financial challenges  
9       experienced by the Company in 2023 as further discussed by Witness Bruzzano  
10      and is not expected to recur in the projected test period. The required Known and  
11      Measurable adjustment to eliminate this temporary reduction is reflected on Exhibit  
12      A-13, Schedule C5.11 page 2, line 17, column (c). The adjusted 2023 Wellness  
13      Program expense is projected to increase from \$4.830 million to \$5.454 million, in  
14      the projected test year, before the impact of the VSIP, based on the overall  
15      healthcare trend annual escalations of 4.67% in 2024, 4.16% in 2025, and 3.59% in  
16      2026, as previously described.

17

18   **Q49. How did you project the Company's Life Insurance Expense?**

19   A49. The Company's Life Insurance expense relates to life insurance provided to  
20      employees that provides coverage that is generally equal to the employees base  
21      annual salary. Because life insurance coverage is based on employee salaries, I  
22      have adjusted the 2023 expense by the annual wage escalation of 3.5% in 2024 and  
23      3.0% in 2025 and 2026, which produces a Life Insurance expense in the projected  
24      test year of \$141,000, before the impact of VSIP, as reflected on Exhibit A-13,  
25      Schedule C5.11, page 2, line 18, column (l).

Line  
No.

1 **Q50. How have you projected the Company's Long-Term Disability Expense?**

2 A50. Actual 2023 Long-Term Disability Expense of \$1.238 million is projected to  
3 increase to \$1.359 million during the projected test year, before the impact of VSIP,  
4 based on the assumption that disability claims costs are primarily driven by labor  
5 costs escalations, which are assumed to be 3.5% in 2024 and 3.0% in 2025 and  
6 2026 , as reflected on Exhibit A-13, Schedule C5.11, page 2, line 19, column (l).

7  
8 **Q51. What adjustments are you proposing to the Company's 2023 General Benefit**  
9 **expense?**

10 A51. The Company's 2023 General Benefit expense, as reflected on Exhibit A-13,  
11 Schedule C5.11, page 2, line 20, is first adjusted for one Known and Measurable  
12 Item to reflect the resumption of the Company's tuition reimbursement program  
13 and employee service awards that were temporarily suspended in 2023 due the  
14 Company's financial challenges as noted above in Q47. Because there is  
15 considerable variability among years for these two costs, I have computed the  
16 required adjustment based on a five-year average for the years 2018 through 2022  
17 (of \$1.901 million) and compared that amount to the Company's actual 2023 costs  
18 (of \$0.971 million). This results in an increase of \$0.929 million in costs for these  
19 two programs or an increase in the Company's expense of \$0.545 million, net of  
20 the portion of the costs capitalized. The Commission recognized a similar  
21 normalization adjustment in its Order in Case No. U-21534. This normalized 2023  
22 expense of \$1.850 million is then escalated by the projected increases in the  
23 Consumer Price Index through the end of the projected test year, which results in  
24 projected General Benefit Expense of \$2.025 million, before the effect of the VSIP,  
25 as reflected on Exhibit A-13, Schedule C5.11, page 2, line 20, column (l).

Line  
No.

1   **Q52. How did you develop the projections for the other items included in Other**  
2       **Benefits on Exhibit A-13, Schedule C5.11?**

3   A52. Lines 21 through 24 of Exhibit A-13, Schedule C5.11 show the components of the  
4       other items included in the Company's Other Benefits. The 2023 ACA expense of  
5       \$23,000 on line 21 reflects the actual expense recognized for the Comparative  
6       Effectiveness Research Fee, which is escalated at the annual Active Healthcare  
7       inflation rates, resulting in \$26,000 of ACA expense for the projected test year. The  
8       actual 2023 Benefit Plan Administration Fees (line 22) are escalated based on the  
9       projected increases in the Consumer Price Index through the end of the projected  
10      test year, which results in Benefit Plan Administration Fees of \$5.780 million,  
11      before the impact of the VSIP. Also included in Other Benefits, Exhibit A-13  
12      Schedule C5.11 are Retirement Administration Fees (line 23), O&M Project  
13      reimbursements (line 24), which are sponsored by Company Witnesses Fix and  
14      Uzenski, respectively.

15

16   **Q53. Have you estimated the impact of the Company's VSIP?**

17   A53. Yes. On page 2 of Exhibit A-13, Schedule C5.11, column (m), I have allocated the  
18      total Employee Benefits expense savings of \$4.151 million associated with the  
19      VSIP provided by Company Witness Leslie. These total savings were calculated  
20      exclusive of the Company's Pension and OPEB expenses because the Company  
21      excludes these expenses from its revenue requirement.

Line  
No.

1   **Q54. What are the Company's total projected employee pensions and benefits**  
2       **expenses for the projected test year?**

3   A54. The total projected employee pensions and benefits expenses of \$84.649 million is  
4       reflected on Exhibit A-13, Schedule C5.11, line 26. After adjustments for the  
5       impact of the portion of these costs to be capitalized and transferred, as well as the  
6       elimination of costs allocated to the Company's separate surcharge programs, as  
7       sponsored by Witness Uzenski, employee pensions and benefits expenses for the  
8       projected test year are reduced to \$67.815 million, as reflected on Exhibit A-13,  
9       Schedule C5.11, line 30.

10

11   **Q55. Does this complete your direct testimony?**

12   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 )  
its rate schedules and rules governing the )  
distribution and supply of electric energy, and )  
for miscellaneous accounting authority. )

Case No. U-21860

QUALIFICATIONS  
  
AND  
  
DIRECT TESTIMONY  
  
OF  
  
MATTHEW A. FIX

**DTE ELECTRIC COMPANY**  
**QUALIFICATIONS AND DIRECT TESTIMONY OF MATTHEW A. FIX**

Line  
No.

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

2    A1.    My name is Matthew A. Fix. My business address is DTE Energy Company, One  
3           Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate  
4           Services, LLC (DTE LLC), a subsidiary of DTE Energy Company (DTE Energy).

6   **Q2.    On whose behalf are you testifying?**

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

9   **Q3.    What is your educational background?**

10   A3.    I received a Bachelor of Business Administration with a major in human resources  
11           and a Bachelor of Arts with a major in psychology from the University of Michigan  
12           – Dearborn in 2008. I received a Master of Business Administration with a finance  
13           concentration from the University of Michigan – Dearborn in 2013.

15   **Q4.    What is your current position and work experience?**

16   A4.    My current position is Director of Compensation and Retirement Income, which I  
17           have occupied since 2022. I joined DTE LLC full-time in 2009 and held positions  
18           with increasing responsibility in Human Resources. I became Manager of HR  
19           Client Relations in 2013, Manager of Compensation in 2017, and assumed  
20           responsibility for Retirement Income in 2021.

22   **Q5.    What are your current responsibilities as Director of Compensation and  
23           Retirement Income?**

24   A5.    As Director of Compensation and Retirement Income, I have overall responsibility  
25           for the design, implementation, and administration of DTE Energy's, including

Line  
No.

1 DTE Electric's, compensation and retirement income related plans, policies, and  
2 practices.

3

4 **Q6. Have you previously testified in DTE Electric proceedings before the Michigan**  
5 **Public Service Commission (MPSC or Commission)?**

6 A6. Yes. I testified in Case No. U-21534, DTE Electric's most recent general rate case.

Line  
No.

1 **Purpose of Testimony**

2 **Q7. What is the purpose of your testimony?**

3 A7. My testimony will present an overview of employee compensation practices and  
4 benefit expense related to retirement income for DTE Electric for the 2023  
5 historical test period and the 12 months ended December 31, 2026, projected test  
6 period. Specifically, I will:

7 1. Provide support for the Company's projected pension costs, Employee Savings  
8 Plan Expense and other retirement income benefits;

9 2. Support the Company's labor cost escalation assumptions used in Company  
10 Witness Uzenski's development of the composite inflation factors for the  
11 projected test period;

12 3. Provide an overview of the Company's compensation philosophy for non-  
13 represented employees and the role that the Company's incentive plans play in  
14 the overall reasonableness of its total compensation policies, including an  
15 analysis of salaries for non-represented positions as of December 31, 2023,  
16 relative to the market medians for comparable positions;

17 4. Describe the components of the Company's short-term and long-term incentive  
18 compensation plans and support the inclusion of such cost in the Company's  
19 revenue requirement, exclusive of the costs related to DTE Energy's Top Five  
20 Executive Officers;

21 5. Demonstrate that the quantifiable customer benefits of the Company's incentive  
22 compensation plans exceed the corresponding expense, as required by the  
23 Commission's traditionally mandated cost/benefit analysis of incentive  
24 compensation expense, and,



Line  
No.

1 6. Provide an explanation of the Company's weighted average results for the  
2 Operating Measures of its incentive compensation plans, as directed by the  
3 Commission in its Order in Case No. U-21534.

4  
5 In summary, my testimony will support the reasonableness and validity of the  
6 projected employee benefits and compensation expense to be incurred by DTE  
7 Electric for the projected test period.

8

9 **Q8. Are you sponsoring any exhibits in this proceeding?**

10 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    | C5.12.1  | Projected Operation and Maintenance Expenses – Pension Cost - Qualified                            |
| A-21    | K1       | Employee Compensation Market Analysis: December 31, 2023                                           |
| A-21    | K2       | 2024 Annual Incentive Plan and Rewarding Employees Plan Metrics: DTE Electric Company              |
| A-21    | K3       | 2024 Annual Incentive Plan and Rewarding Employees Plan Metrics: Nuclear Generation                |
| A-21    | K4       | 2024 Annual Incentive Plan and Rewarding Employees Plan Metrics: DTE Energy Corporate Services LLC |

Line  
No.

|   |      |    |                                                  |
|---|------|----|--------------------------------------------------|
| 1 | A-21 | K5 | 2024 Long-Term Incentive Plan Performance Shares |
| 2 |      |    | Metrics                                          |
| 3 | A-21 | K6 | 2024 Incentive Plans Cost/Benefit Analysis       |
| 4 | A-21 | K7 | AIP/REP Weighted Operating Measures Results:     |
| 5 |      |    | 2019-2023                                        |

6

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

8 A9. Yes, they were. Portions of Exhibit A-13, Schedule C5.11 are sponsored by  
9 Witnesses Cooper and Uzenski.

10

11 **Q10. What is reflected on Exhibit A-13, Schedule C5.11?**

12 A10. Exhibit A-13, Schedule C5.11 reflects the Company's projected Employee  
13 Pensions and Benefits expense for the projected test year. This exhibit is sponsored  
14 jointly with Company Witness Cooper. Page one of this exhibit is a recap of the  
15 Company's Employee Pensions and Benefits expense for both the historical test  
16 year, in column (b), and the projected test year, in column (d). Page two of this  
17 exhibit provides the components of the required adjustments to the historical test  
18 year to develop the Company's Employee Pensions and Benefits expense for the  
19 projected test year. Specifically, Known and Measurable adjustments are reflected  
20 in columns (c) through (e) to develop the Adjusted Historical Test Period expense  
21 levels. The Adjusted Historical Test Period expense is further adjusted for expected  
22 escalations or specific projections, as reflected in columns (g) through (k) to  
23 produce the Employee Pensions and Benefits expense for the projected test year,  
24 exclusive of the VSIP savings, as reflected in column (l).

Line  
No.

1   **Q11. What are the Known and Measurable adjustments?**

2   A11. Exhibit A-13, Schedule C5.11 reflects two categories of Known and Measurable  
3       adjustments that relate to 1) Temporary items, which are sponsored by Company  
4       Witness Cooper, and 2) Normalization Adjustments.

6   **Q12. What is reflected in Normalization Adjustments?**

7   A12. Normalization Adjustments include specific adjustments to certain cost  
8       components to address the impact of unusual expenses recognized in 2023 that need  
9       to be eliminated to produce a recurring level of Employee Benefits prior to any  
10      escalations through the end of the projected test year. The specific adjustments will  
11      be explained in the discussion of the individual cost components.

13   **EMPLOYEE PENSION COSTS**

14   **Q13. What are pension costs?**

15   A13. Pension costs are those costs related to retirement benefits for the employees of  
16       DTE Electric that are eligible to participate in the Company's defined benefit  
17       pension plans. The Company's defined benefit pension costs are recognized under  
18       Financial Accounting Standard Board's Accounting Standard Codification (ASC)  
19       Section 715-30 (ASC 715-30). Costs for the Company's Savings Plan and other  
20       defined contribution benefits are recognized separately.

22   **Q14. What are the components of pension costs?**

23   A14. Pension costs are measured at the beginning of each fiscal year, under ASC 715-  
24       30, and include the following four pension cost components:

Line  
No.

1       Service Costs: Service Costs represent the pension benefits earned by active  
2       employees, on a present value basis, during the current period. Service Costs are  
3       measured based on the expected benefits to be paid based on actuarial assumptions  
4       including current and projected salaries, expected employee turnover, and life  
5       expectancy.

6  
7       Interest Costs: Interest Costs are the increase in the Projected Benefit Obligation  
8       (PBO) due to the passage of time during the current period. The PBO is the  
9       actuarial present value of benefits attributable to the pension benefit formula and  
10      service accrued to date discounted back to current dollars at a discount rate selected  
11      at the prior year-end. A discount rate of 5.00% was used in determining the PBO  
12      as of December 31, 2023. Measuring the PBO as a present value at the beginning  
13      of each fiscal year requires the accrual of an interest cost for the current period at a  
14      rate equal to the prior year's discount rate. The discount rate used in measuring  
15      Interest Costs, as well as Service Costs for the 2023 historical test period, was  
16      5.19%, based on the interest rate environment at the end of 2022, and projected  
17      benefit payments from the pension plan matched against a yield curve of corporate  
18      bond rates, rated AA or higher, provided by Aon, the Company's independent  
19      actuarial firm. This was then reviewed by PriceWaterhouseCoopers (PwC), the  
20      Company's independent accounting firm in connection with its audit of the  
21      Company's financial statements as filed with the Securities and Exchange  
22      Commission (SEC). The 5.00% discount rate used for determining Interest Costs  
23      and Service Costs for the projected test year is based on the discount rate as of  
24      December 31, 2023, which reflects the traditional assumption that high-quality

Line  
No.

1 corporate bond yields at the end of 2025 will remain unchanged from the rates  
2 prevailing at the end of the historical test year.

3

4 Expected Return on Assets: The Expected Return on Assets (ERoA), which is an  
5 offset to pension costs, is an estimate of the expected investment return during the  
6 current period, on the Market Related Value of the assets invested in the pension  
7 trust at the beginning of the year adjusted for any expected funding activity and  
8 projected benefit payments for the year. While actual year-to-year investment  
9 returns can vary significantly, the ERoA is determined based on forward-looking  
10 long-term financial market expectations to avoid large swings in pension costs  
11 based on short-term investment performance. DTE Electric's expected annual  
12 return was 7.60% during the 2023 historical test year, as developed by NEPC LLC,  
13 the Company's independent investment consulting firm, and reviewed by PwC in  
14 connection with its audit of the Company's financial statements as filed with the  
15 SEC. The ERoA is 8.00%, 8.10% and 7.90% in 2024, 2025, and 2026, respectively.  
16 These ERoAs are based on market conditions and pension funding status as of late  
17 2023 and projected changes in funded status.

18

19 Amortizations: In addition to current period costs described above, pension costs  
20 also include the effect of the delayed recognition of prior period costs. This  
21 includes Unrecognized Gains and Losses and Prior Service Costs. Unrecognized  
22 Gains and Losses are changes in the amount of either the PBO or the plan's assets  
23 resulting from experience different from that assumed in actuarial assumptions.  
24 Most notably, since discount rates and return on assets assumptions are based on  
25 either point in time measurements or long-term estimates of expected returns,

Line  
No.

1 differences arise whenever a change is made in the discount rates or when the actual  
2 asset returns differ from long-term expectations. These gains and losses are  
3 deferred and the amount of the unrecognized balance in excess of a corridor equal  
4 to 10% of the greater of the PBO or the Market Related Value of assets is amortized  
5 based on a period equal to the average remaining service life of employees covered  
6 by the plans. Prior Service Costs arise from pension plan amendments that affect  
7 future benefits. When a plan provision is changed that will affect future benefit  
8 payments for existing employees or retirees, the resulting change in the PBO  
9 liability is amortized over the average remaining service life of the active  
10 employees.

11

12 **Q15. What is the level of pension funding reflected in the projected pension costs?**

13 A15. Based on the pension funding status on December 31, 2023, the Company is not  
14 expected to fund pension plans in 2024, 2025 or 2026. While there is no planned  
15 funding of DTE Electric's pension trust, the Company plans to transfer \$25 million  
16 of pension assets related to the DTE Gas Non-Union pension trust assets to DTE  
17 Electric's pension trust assets in the years 2025 and 2026 in exchange for cash  
18 consideration. The reasons for these transfers are explained by Witness Uzenski.

19

20 **Q16. How are pension costs expected to change between the historical test year and**  
21 **the projected year?**

22 A16. As summarized on Exhibit A-13, Schedule C5.12.1, line 10, the Company's  
23 pension costs are projected to increase from negative \$52.003 million during the  
24 historical test year to \$38.551 million for the projected test year. After adjustments  
25 for the portion of pension costs capitalized and transferred, the Company's

Line  
No.

1 projected pension expense is \$19.872 million, as reflected on Exhibit A-13,  
2 Schedule C5.12.1, line 17.

3

4 **Q17. Is the pension expense included in the Company's proposed revenue**  
5 **requirement?**

6 A17. No. Witness Uzenski sponsors the Company's proposal to continue to defer the  
7 projected pension expense to the accumulated regulatory liability as initially  
8 authorized by the Commission in its Order in Case No. U-20836. Thus, the  
9 projected pension expense is not reflected in the Company's proposed revenue  
10 requirement and the pension expense is eliminated on line 18 of Exhibit A-13,  
11 Schedule C5.12.1.

12

13 **EMPLOYEE SAVINGS PLAN COSTS**

14 **Q18. What is included in Employee Savings Plan expense reflected on Exhibit A-13,**  
15 **Schedule C5.11, line 5?**

16 A18. The Company's Employee Savings Plan is an employee benefit plan that allows  
17 eligible employees the opportunity to contribute a certain percentage of their annual  
18 earnings that the Company matches, generally up to 6% of annual salaries and  
19 wages for non-represented employees and for most represented groups. In addition,  
20 employees hired after the Company's defined benefit pension plans were closed to  
21 new hires receive an additional Company contribution of 4.0% of their pay.

Line  
No.

1   **Q19. What adjustments are you proposing to the Company's Employee Savings**  
2       **Plan expense?**

3   A19. As reflected on page 2 of Exhibit A-13, Schedule C5.11, line 5, I am proposing an  
4       adjustment to the Company's actual 2023 Employee Savings Plan expense, which  
5       is reflected in column (k), that represents the projection of the Employee Savings  
6       Plan expense through the end of the projected test year. This adjustment increases  
7       the Employee Savings Plan expense to \$31.141 million, before the impact of the  
8       VSIP.

9

10   **Q20. How was the projected Employee Savings Plan expense developed?**

11   A20. The projected Employee Savings Plan expense was developed based on the total  
12       eligible employee earnings of active participants in the plans as of December 31,  
13       2023, and the percentage of Company contributions. The eligible employee  
14       earnings was increased by 3.5% in 2024 and 3.0% in 2025 and 2026 to reflect the  
15       projected pay increases and the most recent five-year average of actual new plan  
16       participants prorated for the assumption that the new participants would be added  
17       evenly throughout the year (i.e., divided by two). The actual 2023 percentage  
18       Company contribution was applied to the adjusted eligible employee earnings to  
19       develop the annual Employee Savings Plan costs. These costs were reduced by the  
20       five-year average of employee forfeitures of unvested Company contributions.  
21       This results in total Employee Savings Plan costs of \$57.084 million for the  
22       projected period. This amount is reduced by the proportion of costs capitalized of  
23       45.4% to produce an Employee Savings Plan expense for the projected test period  
24       of \$31.141 million, before the impact of the VSIP. This represents an average  
25       annual increase of 4.5%.



Line  
No.

1 **OTHER EMPLOYEE BENEFITS COSTS**

2 **Q21. What are Other Benefits Costs?**

3 A21. The costs of the Company's Other Employee Benefits are also reflected on Exhibit  
4 A-13, Schedule C5.11 (lines 13 through 24). These costs include a variety of other  
5 benefits including, Supplemental Severance Plan, Supplemental Savings Plan  
6 (SSP), Deferred Compensation and Retirement Administration Fees. The  
7 remaining Other Benefits Costs are described by Company Witness Cooper.

8

9 **Q22. What is the Supplemental Severance Plan?**

10 A22. The Supplemental Severance Plan, which was implemented on July 1, 2016, is  
11 designed to address the differences in full benefit eligibility retirement ages  
12 between the DTE Traditional Pension Plan and the MCN Energy Group, Inc (MCN)  
13 Traditional Pension Plan. As a severance plan, in accordance with the regulations  
14 of the U.S. Department of Labor, it is not subject to participation, vesting and  
15 funding requirements of ERISA. Eligible employees will receive a lump sum  
16 payment equal to the present value of the difference between the DTE Pension Plan  
17 and the MCN Pension at the termination of employment.

18

19 **Q23. What adjustments are you proposing to the Supplemental Severance Plan?**

20 A23. The Supplemental Severance Plan adjustment on page 2 of Exhibit A-13, Schedule  
21 C5.11, line 14, column (k) is a reduction of \$73,000, based on the projection of  
22 Supplemental Severance Plan expense provided by Aon for the projected test year  
23 of \$113,000, before the impact of the VSIP.

Line  
No.

1   **Q24.   What is the Supplemental Savings Plan?**

2   A24.   The SSP is a non-qualified benefit plan that does not meet the requirements under  
3           the Internal Revenue Code to be eligible for certain tax advantages, such as the  
4           deductibility by the Company of any contributions. Each year, the Internal  
5           Revenue Service (IRS) establishes limitations on employee annual eligible  
6           compensation and annual contributions to tax advantaged plans. To the extent an  
7           employee's annual eligible compensation or annual contributions, including the  
8           Company's match, to the Company's qualified plan exceeds the IRS limitations,  
9           employees that are Director level and above are eligible to participate in the SSP.  
10          By participating in the SSP, employees accrue benefits that are identical to the  
11          benefits available under the qualified savings plan. As such, the SSP is a "make-  
12          whole" benefit plan that merely puts the participating employees in the same place  
13          they would be in the absence of the IRS limitations.

14

15   **Q25.   What adjustments are you proposing to the SSP expense?**

16   A25.   I am proposing a normalization adjustment to SSP expense which adjusts the actual  
17          2023 SSP expense for the difference between actual and projected returns on the  
18          designated investments in 2023, which decreases the SSP expense by \$1.242  
19          million.

20

21   **Q26.   What is the normalization adjustment for 2023 SSP expense?**

22   A26.   Since the Company does not separately fund the Company's matches to the  
23          employees' contributions, the earnings and losses from the employees' directed  
24          investments is a cost incurred by the Company. The SSP normalization adjustment  
25          reflects an annual return on the investments of 7.60% in 2023, which is based on

Line  
No.

1 the ERoA used in the determination of the Company's pension costs in the  
2 historical test year. This results in a normalized 2023 SSP expense of \$1.828  
3 million.

4  
5 **Q27. What is the basis for the SSP expense for the projected test year?**

6 A27. As shown on page 2 of Exhibit A-13, Schedule C5.11, line 15, the normalized 2023  
7 SSP expense of \$1.828 million is projected to increase to \$2.407 million for the  
8 projected test year, before the impact of the VSIP. This increase reflects an increase  
9 in the expected earnings on designated investments and the projected growth in the  
10 investment balances. The SSP projection reflects an annual return on the  
11 investments of 8.00% in 2024, 8.10% in 2025 and 7.90% in 2026, consistent with  
12 the ERoA used in the determination of the Company's pension costs in the  
13 projected test year, as discussed above.

14  
15 **Q28. What adjustments are you proposing to Deferred Compensation Plan**  
16 **expense?**

17 A28. I am proposing a normalization of the actual 2023 Deferred Compensation expense  
18 for the difference between the actual and expected return on the designated  
19 investments in 2023. In addition, I projected Deferred Compensation Plan expense  
20 through the end of the projected test year.

21  
22 **Q29. What is the normalization adjustment for 2023 Deferred Compensation**  
23 **expense related to the return on the designated investments?**

24 A29. Similar to the SSP, the Company's recorded costs are based on the return on the  
25 investment directives of the participating employees since the deferrals are not

Line  
No.

1 funded by the Company. The Deferred Compensation normalization adjustment  
2 reflects an annual return on the investments of 7.60% in 2023, which is based on  
3 the ERoA used in the determination of the Company's pension costs in the  
4 historical test year. This results in a normalized Deferred Compensation expense  
5 of \$45,000. The decrease in Deferred Compensation expense reflects the difference  
6 between the actual return on the investments in the Deferred Compensation  
7 balances in 2023 and the Pension ERoA of 7.60%.

8

9 **Q30. What is the basis for the projected Deferred Compensation Plan expense?**

10 A30. The increase in the normalized 2023 Deferred Compensation Plan expense of  
11 \$45,000 to \$58,000 for the projected test year, before the impact of the VSIP, as  
12 shown on Exhibit A-13, Schedule C5.11, page 2, line 16, column (l), reflects an  
13 increase in the expected earnings on designated investments and the projected  
14 growth in the investment balances. The Deferred Compensation Plan projection  
15 reflects an annual return on the investments of 8.00% in 2024, 8.10% in 2025 and  
16 7.90% in 2026, consistent with the ERoA used in the determination of the  
17 Company's pension costs in the projected test year.

18

19 **Q31. How did you develop the projections for Retirement Administration Fees**  
20 **included in Other Benefits on Exhibit A-13, Schedule C5.11, page 2?**

21 A31. Retirement Administration Fees (line 23) in 2023 of \$239,000 is increased based  
22 on projected overall inflation rate assumptions to \$262,000 for the projected test  
23 year, before the impact of the VSIP.

Line  
No.

1 **LABOR COST ESCALATION**

2 **Q32. What annual labor cost escalation assumptions are appropriate for the**  
3 **projected test period?**

4 A32. Annual labor cost escalation assumptions are required for both the Company's  
5 represented and non-represented employees. Based on existing Collective  
6 Bargaining Agreements, the Company is obligated to increase pay rates by at least  
7 3% annually through the term of the contracts. In addition to scheduled pay rate  
8 increases, the agreements also provide for progression increases for those  
9 employees that have not yet achieved the maximum pay rate for their positions.

10

11 Non-represented employee compensation is generally adjusted annually based on a  
12 review of pay practices of other employers, changes in the external competitive  
13 market and internal pay equity. Consistent with this practice, all non-represented  
14 non-management employees received an overall pay increase of 3% in 2023. This  
15 3% pay adjustment was comparable to the annual pay adjustments in every year  
16 since 2010. In addition to the annual pay adjustment program, employees generally  
17 receive pay increases based on promotions. In March of 2024 and March of 2025,  
18 the Company implemented an annual Base Pay Review for its non-represented  
19 employees that provided for average annual pay increases of 3.5% and 3.0%,  
20 respectively.

21

22 Based on the above, annual escalations of 3.5% for 2024, and 3.0% for 2025 and  
23 2026 are a conservative estimate of the Company's expected increase in its labor  
24 rates.

Line  
No.

1 **EMPLOYEE COMPENSATION**

2 **Q33. What is the Company's compensation philosophy and framework for non-**  
3 **represented employees other than Executives?**

4 A33. Non-represented employees are employees not covered by any Collective  
5 Bargaining Agreements with the Company's union organizations. Compensation  
6 for employees covered by Collective Bargaining Agreements is established  
7 pursuant to negotiations. Non-executive employees are generally defined as those  
8 with titles below Vice President level. DTE Electric's compensation philosophy is  
9 to provide pay programs that: 1) attract, retain, and motivate employees; 2) ensure  
10 that pay is externally competitive (i.e., paid near market median); and 3)  
11 differentiate total rewards based on both organizational unit results and individual  
12 contributions.

13

14 At DTE Electric, total annual compensation for all non-represented employees has  
15 two primary components: base pay and variable pay, as delivered through the  
16 Company's incentive compensation programs. Employee base pay is reviewed  
17 annually and adjusted (if appropriate) based on the position relative to what the  
18 external market pays for similar positions and individual performance. Variable  
19 pay is based on the achievement of the Company, as well as departmental and  
20 individual results. Variable pay is made up of both short-term and long-term  
21 incentive plans.

Line  
No.

1   **Q34. How does the Company's philosophy regarding incentive compensation**  
2       **compare with that of its peers?**

3   A34. Incentive compensation programs are a component of total compensation practices  
4       for the vast majority of energy companies for their non-represented employee  
5       populations, as described below. Base pay is set lower than it otherwise would be  
6       because of the variable pay component. When considered holistically, the  
7       Company's base and variable pay plans provide a framework of market-based total  
8       annual compensation pay opportunities for non-represented employees. It is the  
9       total annual cash compensation, as represented by these two components, that  
10      prospective and current employees use to gauge whether DTE Electric's  
11      compensation is competitive with other potential employers.

12

13   **Q35. How does the Company's non-represented compensation philosophy and**  
14       **framework benefit customers?**

15   A35. DTE Electric's compensation philosophy and framework provides a benefit to  
16       customers by attracting and retaining employees with the requisite skills and  
17       experience to ensure safe, reliable, and high-quality customer service delivery, and  
18       by recognizing and rewarding effective and efficient performance. A competitive  
19       compensation policy also serves to effectively retain employees, minimizing the  
20       inherent risks and costs of high employee attrition. This philosophy directly  
21       benefits all customers by providing a high level of service at a competitive cost and  
22       provides incentives to focus future job performance on those activities that provide  
23       the most benefit to customers.

Line  
No.

1   **Q36. What is the external comparative market used by the Company to determine**  
2       **the external market for compensation?**

3   A36. The external comparative market for positions varies based on the specific job.  
4       Some jobs are compared to those in utilities of similar size (e.g., revenue, number  
5       of employees, etc.), other jobs are compared to general industry located in  
6       Southeastern Michigan, and yet other jobs to general industry located within the  
7       United States. The relevant market will depend upon the requisite skills and  
8       abilities required of the job and the nature of the recruitment source. For example,  
9       the comparative market for an administrative assistant is the general industry within  
10      Southeastern Michigan while the comparative market for a manager of nuclear  
11      operations is utilities within the Midwestern United States (primarily), or within the  
12      entire United States (secondarily).

13

14   **Q37. How is benchmark data obtained from the external comparative market?**

15   A37. The Company participates in and/or purchases published salary surveys from  
16       several different organizations. The surveys typically report median base salary,  
17       target incentives, and median total cash compensation by job classification.

18

19   **Q38. How are base salaries determined?**

20   A38. Base salaries are targeted around the median base salary levels of the competitive  
21       market as adjusted for differences in company size and scope where appropriate.  
22       All non-executive positions are placed in a salary zone based on external  
23       benchmarking. The mid-point of the salary zone is based on the market median for  
24       comparable work in comparable companies. A range is provided above and below  
25       the midpoint to allow for differentiation based on applicable skills and experience,



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1 as well as demonstrated performance. The ranges are reviewed periodically to help  
2 ensure they remain competitive in the external market.

3

4 **Q39. Does the Company benchmark the variable component of compensation?**

5 A39. Yes. The Company reviews several surveys that provide information on a number  
6 of variable pay indices. In addition, the surveys report data for employee groupings  
7 such as exempt employees, non-exempt employees, managers, and executives.

8

9 **Q40. Could an alternate compensation system be structured, eliminating variable**  
10 **components?**

11 A40. Yes. The Company could raise employees' base pay to the market levels for total  
12 compensation in lieu of providing variable pay opportunities to maintain a  
13 competitive total compensation level. However, this would have several  
14 undesirable effects. For example, raising employees' base pay to the total  
15 compensation market levels would result in a higher level of fixed costs tied to base  
16 salaries, such as certain defined contribution benefit plans, life insurance, disability  
17 insurance, and other salary-based employee benefits. Moreover, given the well-  
18 recognized motivational value of variable pay compensation programs, as  
19 described below, delivering employee compensation solely in fixed salary would  
20 diminish the performance incentive for employees to provide superior service to  
21 customers. Annual incentives ensure that individuals have an element of "at risk"  
22 compensation that allows the Company to differentiate pay based on performance  
23 and allocate compensation to those employees that are most deserving.

Line  
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1 **EXECUTIVE COMPENSATION**

2 **Q41. How does the executive compensation program differ from that of non-**  
3 **executives?**

4 A41. The compensation program for executives differs in three respects. First, the  
5 comparative market for compensation benchmarking is defined as a specific group  
6 of peer companies from which data are obtained through a custom study generally  
7 performed every two years. Second, a higher proportion of executives'  
8 compensation is delivered in the form of variable pay. The third way in which the  
9 executive compensation program differs is with respect to governance. The  
10 compensation programs for Company executives must be approved by the  
11 Organization and Compensation Committee of the DTE Energy Board of Directors.

12

13 **Q42. What is the comparative market for executive compensation?**

14 A42. The comparative market used by DTE Energy for determining the alignment of its  
15 executive compensation programs with similar companies consists primarily of  
16 utilities (including utility holding companies) and broad-based energy companies  
17 selected on the basis of revenues, financial performance, geographic location, and  
18 availability of compensation information.

19

20 **Q43. What are the key components of the Executive Compensation Program?**

21 A43. The key elements of the Executive Compensation Program are base salary and  
22 variable pay (annual incentive plan and long-term incentive awards).

Line  
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1   **Q44. How are base salaries determined?**

2   A44. Base salaries are targeted around the median of the comparative market.  
3       Appropriate methods of measurement are used to consider differences in company  
4       size and scope. In addition, midpoints are established for those executives whose  
5       jobs cannot be easily matched in the comparative market. These midpoints are  
6       designed to allow adequate differentiation for 1) individual potential, 2)  
7       contributions made, and 3) the length of time the executive has been in his or her  
8       position.

9

10   **COMPETITIVE COMPENSATION ANALYSIS**

11   **Q45. Has the Company prepared an analysis of its compensation practices relative**  
12       **to the market medians?**

13   A45. Yes. DTE Electric has performed an analysis of virtually all incumbent salaries as  
14       of December 31, 2023, showing that DTE's compensation practices are competitive  
15       with market medians. Exhibit A-21, Schedule K1 reflects a summary of the market  
16       median for all DTE Electric positions for which corresponding positions have been  
17       identified, other than those employees covered by collective bargaining  
18       agreements. In addition, Exhibit A-21, Schedule K1 reflects those positions at DTE  
19       LLC that primarily support DTE Electric and reflects employee compensation  
20       information organized based on Career Family classifications used by DTE  
21       Electric. A Career Family is a grouping of jobs based on similar skill requirements  
22       and job content in a specialized discipline (i.e., Finance, Engineering, Information  
23       Technology, etc.) that may or may not fit into a business unit organizational  
24       structure. For example, Engineering or Finance Career Families could exist in  
25       several organizational units.

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1   **Q46. How is an analysis of a competitive pay structure performed?**

2   A46. An analysis of market-based pay structure is performed by identifying comparable  
3       positions and determining the compensation ranges paid by similar employers in  
4       relevant locations. A more expansive description of the means of assessing a  
5       competitive pay structure is provided in an article published by Salary.com, entitled  
6       The Basics of Market Pricing a Job<sup>1</sup> (January 26, 2017).

7  
8   **Q47. Is the Company's use of a market pricing approach to employee compensation**  
9       **consistent with others?**

10   A47. Yes. According to a survey performed by WorlдатWork and Deloitte Consulting,  
11       entitled 2019 Survey of Salary Structure Policies and Practices, more than half of  
12       the companies surveyed use a market pricing model for setting compensation  
13       levels.

14  
15   **Q48. Why are employees covered by collective bargaining agreements excluded**  
16       **from this analysis?**

17   A48. Compensation levels for unionized employees are determined through a negotiated  
18       process, which involves a variety of work rules and benefit related issues, rather  
19       than determined strictly through market analysis. Moreover, the specialized skills  
20       and experience required by many of the positions are not readily comparable to  
21       other positions in the local market. Thus, a comparison of pay levels for those  
22       employees covered by collective bargaining agreements is not useful in this  
23       context.

---

<sup>1</sup> <https://www.salary.com/blog/basics-market-pricing-job>

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1   **Q49. What conclusions can be drawn from Exhibit A-21, Schedule K1?**

2   A49. In summary, Exhibit A-21, Schedule K1 demonstrates that the weighted average of  
3       the annual base compensation for all positions with incumbents as of December 31,  
4       2023, with available position matches was 2.9% less than the average of median  
5       market base compensation. This analysis further demonstrates that total cash  
6       compensation for all positions with incumbents as of December 31, 2023, with  
7       available position matches was 3.7% less than the average of median market for  
8       total cash compensation. This analysis concludes that the Company's total  
9       compensation is insignificantly different from the market medians and confirms  
10      that the Company's compensation practices are consistent with the Company's  
11      compensation policy to pay employees near the market median for comparable  
12      positions on a total cash compensation basis. Moreover, a comparison of the  
13      Company's base salaries, which excludes short-term incentive compensation, to the  
14      market medians for total cash compensation, which is inclusive of short-term  
15      incentive compensation, shows that in the absence of the Company's short-term  
16      incentive compensation programs, the Company's pay would be 14.3% less than  
17      the market medians, rendering the Company less competitive in attracting and  
18      retaining employees.

19

20   **Q50. What is included in the total cash compensation amounts?**

21   A50. Total cash compensation reflects base pay as of December 31, 2023, and the Target  
22      payout levels for those employees eligible to participate in the Company's short-  
23      term incentive compensation programs. Although the analysis on Exhibit A-21,  
24      Schedule K1 does not reflect the value of the Company's Long-Term Incentive  
25      Plan, as it is primarily for executive level positions, a separate analysis of executive

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1 compensation prepared by Aon, which is inclusive of long-term plans, shows that  
2 total compensation is about 9% less than the median of the Company's peer group,  
3 as discussed in more detail below.

4

5 **Q51. How was the market median for the positions determined?**

6 A51. As described above, the Company subscribes to several compensation survey  
7 providers that create comprehensive databases of job descriptions that enables the  
8 Company to match the job requirements, including education, expertise and  
9 experience of existing positions with market surveys. After matching job positions  
10 are identified, actual base and total compensation ranges are developed from the  
11 salary survey database. The information on Exhibit A-21, Schedule K1 was derived  
12 from the Company's compilation of the compensation for positions with an  
13 incumbent as of December 31, 2023.

14

15 **Q52. What proportion of DTE Electric's total employee population as of December**  
16 **31, 2023, is reflected in this analysis?**

17 A52. As of December 31, 2023, practically all (98.7%) of the employee population at  
18 DTE Electric, as well as DTE LLC employees that provide supporting services to  
19 DTE Electric, are included in the compensation analysis, exclusive of those  
20 employees represented by collective bargaining agreements.

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1 **INCENTIVE COMPENSATION**

2 **Q53. What are you proposing regarding the level of incentive compensation expense**  
3 **to be included in the Company's revenue requirement?**

4 A53. I am proposing that the projected incentive compensation expense of \$56.369  
5 million related to the Company's short-term and long-term incentive compensation  
6 plans be included in the revenue requirement adopted by the Commission in this  
7 proceeding, as described in more detail below. The components of the incentive  
8 compensation expense are detailed in Table 2, as reflected in response to Q80.

9

10 **Q54. Is the Company requesting recovery in rates for all incentive compensation**  
11 **expenses?**

12 A54. No. While the Company's compensation expenses are reasonable, \$10.424 million  
13 of incentive compensation expense related to DTE Energy's Top Five Executive  
14 Officers has been excluded. This exclusion is reflected on Exhibit A-3, Schedule  
15 C19 as supported by Witness Uzenski and has been excluded from Table 2, as  
16 reflected in the response to Q80.

17

18 **Q55. What is the basis for your proposed inclusion of \$56.369 million of incentive**  
19 **compensation expense in the Company's revenue requirement?**

20 A55. In summary, my proposal to include all the Company's projected incentive  
21 compensation expense, exclusive of the portion related to the Top Five Executive  
22 Officers, is based on the prevalence of incentive compensation programs and the  
23 resultant need for the Company to have total compensation programs that enable it  
24 to be competitive with other employers. As described above, the Company's  
25 existing total cash compensation is reasonable given it is in line with the market, as

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1 is the total compensation for its executives. Moreover, in the absence of the  
2 incentive compensation programs, total cash compensation for the Company's  
3 employees would be unreasonable at 14.3% less than the market medians, as  
4 reflected on Exhibit A-21, Schedule K1, and total compensation for its executives  
5 would be 63% less than market, as reflected in Table 1 below in Q60. The  
6 remainder of my testimony will demonstrate that the Company's incentive  
7 compensation programs are both reasonable and prudent and, therefore, a necessary  
8 cost of the Company doing business that should be reflected in the Company's  
9 revenue requirements.

10

11 **Q56. Are there any employee motivational advantages to including an incentive-**  
12 **based compensation component in a company's overall compensation design?**

13 A56. Yes. The underlying principle of incentive compensation plans is to motivate  
14 improved organizational performance. An effective incentive compensation plan  
15 provides a "pay-for-performance" environment intended to motivate individual and  
16 team achievement of measurable goals.

17

18 **Q57. Is there any evidence that incentive-based compensation is effective in**  
19 **motivating improved organizational performance?**

20 A57. Yes. A comprehensive analysis of the impact of incentive compensation plans on  
21 organizational performance concluded that programs that provide tangible  
22 incentives for achievement of certain goals lead to a 27% increase in organizational  
23 performance (Incentives, Motivation and Workplace Performance: Research &  
24 Best Practices, The International Society for Performance Improvement, Spring,  
25 2002). This study observes that the source for such organizational performance



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1 improvements is that employees 1) value their work tasks more, 2) have more self-  
2 confidence and esteem for their employers, 3) are more persistent at work tasks,  
3 and 4) strive for high levels of accomplishments. Moreover, this study notes that  
4 long-term incentive plans provide even greater performance improvements. In  
5 addition, an Aon Variable Compensation Measurement Survey issued in 2018  
6 reported that 86% of participants in the survey indicated that their variable  
7 compensation plans resulted in improved business results.

8

9 **Q58. Are incentive compensation programs a typical element in compensation at**  
10 **other companies?**

11 A58. Yes. According to a 2021 study issued by WorldatWork and Compensation  
12 Advisory Partners, most companies had short-term and long-term incentive  
13 programs. This indicates that incentive compensation programs are a prevalent  
14 practice among most companies. (Incentive Pay Practices, Publicly Traded  
15 Companies, WorldatWork and Compensation Advisory Partners). Moreover, a  
16 2018 study by Aon of U.S. Salary Increases shows that 90% of Power and Gas  
17 Service providers utilized broad-based incentive compensation programs.

18

19 **Q59. Do the Company's incentive compensation plans result in unreasonable**  
20 **compensation?**

21 A59. No. As explained above, the Company benchmarks its total compensation for non-  
22 represented employees against relevant peers, inclusive of incentive compensation,  
23 and establishes a mid-point salary range based on the median market level.  
24 Moreover, based on a recent survey by Aon, the total compensation of DTE  
25 Energy's Executives is about 9% less than the median of its peers based on Target

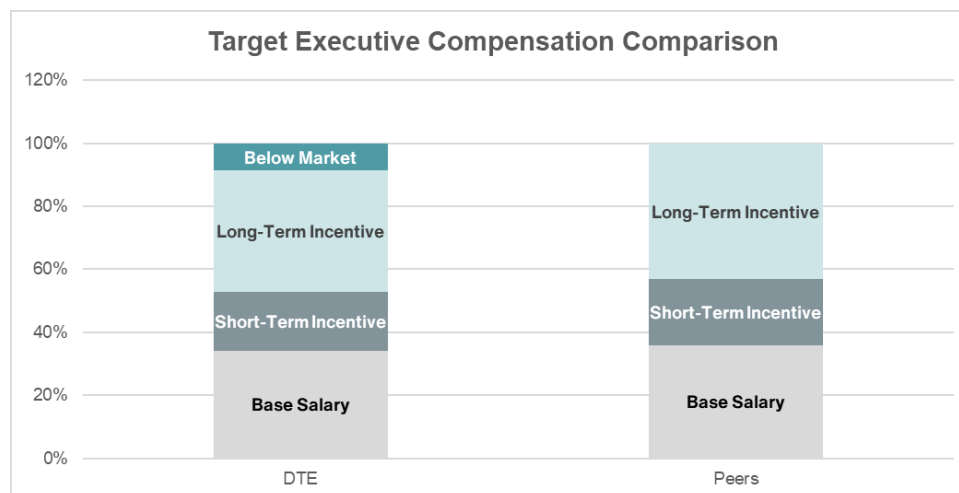
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level performance, inclusive of the long-term incentive compensation. The Company's incentive compensation programs are merely a component of the total compensation policies required for the Company to be competitive with its peers, rather than a supplement. Indeed, in the absence of the incentive compensation programs, total compensation for the Company's non-represented population would be more than 14.3% below market, as reflected on Exhibit A-21, Schedule K1. Additionally, as indicated in Table 1 in the response to Q60 below, DTE Energy's Executives would be substantially less than its peers, since about 63% of total compensation is delivered through short and long-term incentive compensation programs, by both DTE and its peers.

**Q60. How do the components of the Company's total Executive compensation practices compare to the Company's peers?**

A60. 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 relevant market compensation levels of its peers is reflected in Table 1.

**Table 1**



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1   **Q61. What are the specific components of the Company's incentive compensation**  
2       **programs?**

3   A61. The Company has in place incentive compensation plans for both its Executive and  
4       all other non-represented employees. Short-term incentive plans are provided  
5       through the Annual Incentive Plan (AIP) and Rewarding Employees Plan (REP).  
6       Additionally, a multiple year incentive plan, which is available to all managers and  
7       above, is delivered through Performance Shares granted pursuant to the Long-Term  
8       Incentive Plan (LTIP).

9

10   **Q62. What is the AIP?**

11   A62. The AIP is a short-term variable pay program available to senior management level  
12       employees to motivate performance. The 2023 AIP measures and relative weights  
13       for DTE Electric (other than Nuclear Generation), Nuclear Generation, and DTE  
14       Energy Corporate Services LLC are reflected on Exhibit A-21, Schedules K2, K3  
15       and K4, respectively. For each measure, a Target is established for which a 100%  
16       payout will be earned. Performance less than Target, but above a minimum  
17       Threshold, results in a payout between 25% and 100% of Target, performance at  
18       Target results in a payout of 100%, and performance between Target and the  
19       Maximum level results in a payout of up to 175% of Target for non-executive  
20       participants of the AIP and up to 200% of Target for Executive participants of the  
21       AIP.

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1   **Q63. Which employee classifications are eligible to participate in the AIP?**

2   A63. All Executive level employees, generally those with titles of Vice President and  
3       above, and Directors participate in the AIP. All other non-represented employees  
4       are eligible to participate in the REP.

5  
6   **Q64. What are the components of the REP?**

7   A64. The REP is identical to the AIP except that Threshold performance is at 50% of  
8       Target and the Maximum performance payout is 150% of Target. The 2024 REP  
9       measures and weightings are reflected on Exhibit A-21, Schedules K2 through K4.  
10      The REP measures are identical to the AIP measures other than the REP excludes  
11      the Gallup survey of employee engagement measure in recognition that the  
12      Company's leadership is responsible for providing an environment of high  
13      employee engagement.

14  
15   **Q65. What are the categories of measures included in the AIP and REP?**

16   A65. There are four categories of measures in both the AIP and REP. Specifically,  
17      Financial Performance, Customer Satisfaction, Safety and Engagement, and  
18      Operating Excellence.

19  
20   **Q66. What are the financial measures included in the AIP and REP?**

21   A66. There are three financial measures for DTE Electric employees that are designed to  
22      create a clear line of sight for all employees to focus on operating excellence by  
23      rewarding employees when the Company is successful.

24      1) DTE Electric Operating Earnings objective is based on the Company  
25      realizing the Commission authorized return on equity.

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1           2)     DTE Electric's Cash from Operations is similarly based on the authorized  
2                     return on equity but is adjusted for non-cash items. The inclusion of a cash  
3                     flow measure recognizes the importance of DTE Electric maintaining a high  
4                     credit rating to allow continued access to the capital markets at reasonable  
5                     costs and terms to ensure sufficient capital investment to continue to serve  
6                     our customers.

7           3)     DTE Energy's Operating Earnings per Share measure is based on the  
8                     midpoint of 2024 earnings guidance.

9           Nuclear Generation Financial Performance measures consist of DTE Electric  
10           Operating Earnings, DTE Energy's Earnings per Share, and Nuclear Generation  
11           Operation and Maintenance Expense. The Financial Performance measures for  
12           DTE LLC reflect DTE Energy's Earnings per Share and Cash from Operations.

13

14   **Q67. What are the Customer Satisfaction measures?**

15   A67. The customer satisfaction measure is intended to focus employees on improving  
16           the experience that our customers have in their interactions with the Company. The  
17           measure used by the Company is Net Promoter Score, which is the extent to which  
18           customers are likely to recommend the Company to their friends and colleagues.  
19           The Target for 2024 is 33, which is an increase over the actual 2023 NPS of 27.

20

21   **Q68. What are the measures related to Safety and Engagement?**

22   A68. There are three measures related to Safety and Engagement. One measure pertains  
23           to employee engagement as measured by the Gallup survey, as well as two  
24           employee safety related measures, as described below.

Line  
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1   **Q69. What is the measure related to Employee Engagement?**

2   A69. The Gallup measure of Employee Engagement is reflective of the direct correlation  
3       between the level of active employee engagement and the performance of an  
4       organization. The 2024 Target of 4.29 is based on a grand mean of the results of  
5       the Gallup surveys of employees and represents top decile performance relative to  
6       Gallup's overall database. Employee Engagement is a statistically significant  
7       measure of the level of commitment employees have to an organization's success  
8       and is not merely a measure of employee satisfaction. The Employee Engagement  
9       measure relates to leadership roles in the Company and is therefore not an REP  
10      measure.

11

12   **Q70. What are the Safety related measures?**

13   A70. DTE Electric has two safety-related measures.

14       1) The first is the OSHA Recordable Incident Rate (RIR), which measures the  
15       recordable injuries per 100 employees divided by the actual number of hours  
16       worked, as defined by the Occupational Safety and Health Administration  
17       (OSHA). This is a standard measure of safety performance used nationwide.  
18       The measure is intended to create a heightened focus on the importance of  
19       safety in the workplace. The RIR Target for 2024 is .57, which is near the very  
20       top performance in the industry.

21       2) The second is High Energy Serious Injury or Fatality (HSIF), which is a  
22       measure adopted by the Edison Electric Institute that recognizes the degree of  
23       seriousness of an injury in the context of a dangerous event. The 2024 Target  
24       is two HSIF events compared to the 2023 actual of two.

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1   **Q71. What are the Operating Excellence measures for 2024?**

2   A71. DTE Electric has four Operating Excellence measures that reflect specific operating  
3       priorities for 2024 to motivate the achievement of certain operating objectives  
4       important to the Company, its customers, and the Commission. Two of these  
5       measures relate to Distribution System Reliability and the other two relate to  
6       Generation Reliability.

7       The two Electric Distribution Reliability Measures are:

- 8       1)    The percentage of customers that have experienced an electric service  
9            interruption as the result of storm that were restored in 48 hours or less. The  
10          Target in 2024 is 93% compared to the 2023 actual of 81.2%.
- 11       2)    The percentage of customers that experience four interruptions or more  
12          (CEMI4) in a calendar year. The Target in 2024 is 9.3% compared to 2023  
13          actual of 13.37%.

14

15       The two Generation Reliability Measures are:

- 16       1)    The percentage of hours that DTE Electric's coal, gas, and renewable  
17          generating assets are mechanically available to produce power. The 2024  
18          Target is 82.7% compared to a 2023 target of 81.8%.
- 19       2)    Nuclear Annual Unit Capability Factor (UCF), which is the ratio of  
20          available nuclear energy generation to the total possible generation. The  
21          2024 UCF Target is 88.0% compared to 2022 actual of 71.4% which was  
22          the last year in which Fermi conducted a refueling outage.

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1   **Q72. What are the operating measures applicable to the Nuclear Generation**  
2       **business unit?**

3   A72. Nuclear Generation has four Safety and Engagement related measures and four  
4       Operating Excellence measures, discussed below in further detail.

6   **Q73. What are Nuclear Generation's Safety and Engagement related measures?**

7   A73. In addition to the measures described above, Nuclear Generation also has two  
8       additional safety measures:

9           1) The first is the annual Total Industrial Safety Accident Events (TISA  
10           Events), which is a nuclear industry measure that is aligned with the  
11           Institute of Nuclear Power Operations (INPO). The Target is zero incidents  
12           in any calendar year quarter.

13          2) The second relates to Annual Radiation Exposure, which is designed to  
14           maintain a focus on the safety of personnel. The 2024 Target is 350 Rem,  
15           which is a standard unit of measure of exposure to radiation, compared to  
16           521 Rem in 2022, which was the last year in which Fermi conducted a  
17           refueling outage.

19   **Q74. What are the Operating Excellence measures related to Nuclear Generation?**

20   A74. Nuclear Generation has four Operating Excellence measures:

21           1) The first relates to Annual On-Line Reliability Loss Factor (ORLF), which  
22           reflects energy generation losses adjusted for refueling outage losses and  
23           exempt activities (e.g., expected thermal losses).

24          2) The second measure regarding Operational focus pertains to a group of 11  
25           measures that relate to Fermi 2 plant performance.



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1           3) The third measure is Nuclear Equipment and Human Error Consequential  
2           Events, which is intended to ensure the organization maintains focus on  
3           minimizing significant or noteworthy consequential events.

4           4) The final Nuclear Generation measure relates to the Nuclear Refuel Outage  
5           Performance, which includes three measures that are strongly correlated to  
6           a safe and successful outage execution.

7

8   **Q75. Are there other AIPs and REPs that impact DTE Electric's expenses?**

9   A75. Yes. In addition to the DTE Electric and Nuclear Generation measures described  
10       above, there are also AIPs and REPs in place for corporate staff employees at DTE  
11       LLC that provide services to all DTE Energy business units, including DTE  
12       Electric. The DTE LLC measures reflect certain DTE Electric and Nuclear  
13       Generation measures, as well as measures related to DTE Gas. The specific DTE  
14       LLC measures and weightings related to DTE Electric and Nuclear Generation are  
15       reflected on Exhibit A-21, Schedule K4.

16

17   **Q76. What is the Company's Long-Term Incentive Plan?**

18   A76. The LTIP provides the opportunity for certain individuals to receive retention-  
19       oriented or performance-based rewards delivered via shares of DTE Energy  
20       common stock, either Performance Shares, which are based on the achievement of  
21       multi-year performance objectives, or through Restricted Stock. Currently, 70% of  
22       the value of awards for executives and directors is through grants of Performance  
23       Shares and 30% of the value of awards is through Restricted Stock, while 100% of  
24       the awards to other eligible employees are through Performance Shares. The  
25       objective in granting shares through this program is to both motivate superior

Line  
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1 results as well as provide a means to retain key employees and is consistent with  
2 the practices of most companies, as reflected in the WorldatWork and  
3 Compensation Advisory Partners survey, referenced in Q58 above.

4  
5 **Q77. What are the performance share measures used in the 2024 LTIP?**

6 A77. The measures are shown on Exhibit A-21, Schedule K5.

7  
8 **Q78. What is the rationale for the use of these measures?**

9 A78. These measures generally reflect the long-term financial performance of DTE  
10 Energy and are intended to motivate employees of the individual operating  
11 companies, such as DTE Electric, to keep in mind the role of their own  
12 contributions to the overall long-term success of DTE. Accordingly, the  
13 predominate measure for DTE Electric and DTE LLC (80% for both) is the total  
14 return to DTE Energy shareholders (i.e., capital appreciation and dividends)  
15 relative to a group of peer companies over the next three years. The second  
16 financial measure included in the LTIP, which contributes 20% to the total  
17 weighting, is DTE Energy's three-year cumulative Operating Earnings per Share.  
18 The three-year focus of the performance-based measures is designed to motivate  
19 decisions and actions that produce sustainable benefits rather than short-term  
20 actions that may entail long-term risks.

21

22 **Q79. What is the basis for the costs of the LTIP?**

23 A79. The LTIP costs incurred in 2023 pertain to the grants of Performance Shares and  
24 Restricted Stock. The expense related to the Restricted Stock is not conditioned on  
25 any Company performance measures but rather is exclusively based on the number

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1 of shares granted at the date of grant. In contrast, Performance Shares expense is  
2 based on the achievement of the predetermined performance objectives. The  
3 recognized cost of Performance Shares is based on the number of shares granted at  
4 the market price of DTE Energy's common stock at the date of grant but with  
5 adjustment in the number of shares based on actual performance. The Performance  
6 Shares expense included in Table 2 included in Q80 is based on Target  
7 performance.

8

9 **Q80. What is the incentive compensation expense if the Company achieves all of its**  
10 **Financial and Operating Targets?**

11 A80. The net expense to DTE Electric in the projected test period of the Company  
12 achieving all its Targets for the incentive compensation plans, exclusive of the  
13 expense related to the Top Five Executive Officers, is \$56.369 million. The table  
14 below summarizes the expense for the projected test period by the nature of the  
15 plans, the classification of the employees eligible and the basis of the metrics used.

Line  
No.

1

**Table 2**

|              | <u>LTIP</u>     | <u>AIP</u> | <u>REP</u> | <u>Total</u> |
|--------------|-----------------|------------|------------|--------------|
|              | (000's Omitted) |            |            |              |
| Financial    |                 |            |            |              |
| DTE Electric | \$6,413         | \$638      | \$6,728    | \$13,779     |
| Nuclear Gen  | 668             | 89         | 818        | 1,575        |
| DTE LLC      | 10,552          | 2,996      | 6,936      | 20,484       |
|              | 17,633          | 3,723      | 14,482     | 35,838       |
| Operating    |                 |            |            |              |
| DTE Electric | 0               | 502        | 5,287      | 5,789        |
| Nuclear Gen  | 0               | 186        | 2,412      | 2,598        |
| DTE LLC      | 0               | 3,663      | 8,481      | 12,144       |
|              | 0               | 4,351      | 16,180     | 20,531       |
| Total        |                 |            |            |              |
| DTE Electric | 6,413           | 1,140      | 12,015     | 19,568       |
| Nuclear Gen  | 668             | 275        | 3,230      | 4,173        |
| DTE LLC      | 10,552          | 6,659      | 15,417     | 32,628       |
|              | \$17,633        | \$8,074    | \$30,662   | \$56,369     |

2

3 **Q81. Why do the expenses for DTE LLC represent the majority of the incentive**  
4 **compensation expenses?**

5 A81. DTE LLC provides a variety of administrative and other services that are common  
6 to both DTE Electric and DTE Gas for which the costs are billed to the operating  
7 companies, as explained by Witness Uzenski. In addition, DTE LLC employs all  
8 the Executives of DTE Energy, including the Officers of DTE Electric.

9

10 **Q82. How have you reflected the Operating Excellence measures related to DTE**  
11 **Gas in the AIP and REP for DTE LLC?**

12 A82. While the AIP and REP expenses allocated to DTE Electric in the historic period  
13 from DTE LLC include some measures related to DTE Gas, the AIP and REP

Line  
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1 weightings for DTE LLC have been adjusted to exclude the measures specifically  
2 related to DTE Gas.

3

4 **Q83. Are all incentive compensation costs dependent on the Company's financial or**  
5 **operating performance?**

6 A83. No. As described earlier, a portion of the DTE Energy shares granted under the  
7 LTIP are in the form of Restricted Stock. Unlike the Performance Shares, the  
8 expense of Restricted Stock is not variable based on either the Company's financial  
9 or operating performance. The only contingency is that the employee forfeits the  
10 Restricted Stock if they leave the Company, other than through retirement or the  
11 event of the employee's death or disability.

12

13 **Q84. How does the lack of variability in the LTIP expense affect its treatment in**  
14 **your analysis of incentive compensation?**

15 A84. Although Restricted Stock grants are made under the LTIP, the ultimate payouts  
16 are not dependent on future Company or employee performance, and therefore,  
17 Restricted Stock is not regarded as an element of the Company's incentive  
18 compensation expense. Accordingly, the projected test year Restricted Stock  
19 expense of \$7.685 million has been excluded from Table 2 above.

20

21 **Q85. Did the Commission address the issue of Restricted Stock in its Order in Case**  
22 **No. U-21534?**

23 A85. Yes. The Commission disallowed the Restricted Stock expense from the  
24 Company's revenue requirement in Case No. U-21534, based on its determination  
25 that the expense should be excluded for the same reason it excludes the incentive

Line  
No.

1 compensation related to financial measures, namely “the benefits are skewed  
2 towards shareholders than customers” and Commission precedent (Case No. U-  
3 21534, Order, page 277).  
4

5 **Q86. Do you agree with the Commission’s conclusion regarding Restricted Stock?**

6 A86. No. While I disagree with the Commission’s disallowance of the Financial  
7 measures of the Company’s incentive compensation plan in its Order in Case No.  
8 U-21534, the Company’s Restricted Stock expense is completely unrelated to the  
9 Company’s financial results, and therefore, should not be regarded as a financial  
10 measure. Moreover, while Restricted Stock grants are in shares of DTE Energy  
11 Common Stock, the cost to the Company is recognized at the value of those shares  
12 on the date of grant, and therefore, are not variable based on the future price of DTE  
13 Energy’s Common Stock. Indeed, the cost recognized by the Company for the  
14 Restricted Stock upon grant is the same as if the Company had made a promise to  
15 pay cash. The mere fact the Restricted Stock grants are convertible into DTE  
16 Energy’s Common Stock does not make it a financial measure. Last, the benefits  
17 of Restricted Stock relate to the Company’s ability to attract and retain highly  
18 qualified employees, for which both customers and shareholders benefit.  
19 Accordingly, because the Commission’s exclusion of the Restricted Stock expense  
20 is based on this misunderstanding, it would be unreasonable to not include the  
21 Restricted Stock expense in the revenue requirement adopted by the Commission  
22 in this proceeding.

Line  
No.

1   **Q87. Has the Commission provided any criteria for the inclusion of incentive**  
2       **compensation expense in the Company's revenue requirements?**

3   A87. Yes. The Commission has indicated in all its recent Orders addressing incentive  
4       compensation programs that inclusion of incentive compensation expense in a  
5       company's revenue requirement was dependent on a showing that the incentive  
6       compensation programs provided benefits to customers in excess of the expense.

7

8   **Q88. Has the Company performed an analysis of the customer benefits of the**  
9       **Company's incentive compensation plans?**

10   A88. Yes. The Company has performed a comprehensive analysis of the customer  
11       benefits that would be derived from the achievement of the financial and operating  
12       metrics included in the Company's short and long-term incentive plans relative to  
13       their expense. This analysis, as reflected on Exhibit A-21, Schedule K6,  
14       demonstrates that the calculated aggregate benefit of \$95.935 million exceeds the  
15       total incentive compensation expense of \$56.369 million by \$39.566 million.

16

17   **Q89. How did you calculate the benefits of the Financial measures?**

18   A89. The benefits of the Company achieving its Cash Flow from Operations measure is  
19       reflected on line 10 of Exhibit A-21, Schedule K6. This measure is focused on the  
20       Company maintaining its "A" debt rating from Standard & Poor's and comparable  
21       ratings by the other major debt rating firms. The yield spread between utility bonds  
22       for bonds with an "A" rating compared to "BBB" rated bonds is 21 basis points.  
23       Based on the long-term debt balances included in the capital structure sponsored by  
24       Company Witness Vangilder on Exhibit A-14, Schedule D1, a downgrade in the

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No.

1 Company's credit rating would increase the Company's annual interest costs by  
2 \$19.060 million.

3

4 While the Company has not specifically quantified the benefits to customers of the  
5 other Financial measures, customers clearly benefit from the Company having  
6 access to the capital markets at favorable rates and terms, which is made possible  
7 through the Company being financially healthy.

8

9 **Q90. How are the benefits of the Company achieving Target performance for the**  
10 **Operating measures reflected on Exhibit A-21, Schedule K6 determined?**

11 A90. The benefits of the Operating measures are computed based either on the avoided  
12 costs to the Company, which results in lower future revenue requirements, or based  
13 on the value to customers of improved performance. The reference points to  
14 determine improvement are, in most instances, based on the Company's actual  
15 performance in the 2023 historical test year, but when 2023 results are not  
16 representative, either an historical average or a comparison to external peer groups  
17 is used. In those instances in which the Company's Targets are based on superior  
18 performance relative to peers, then measures of peer performance are used. The  
19 benefits of achieving Target performance are allocated between the AIP and REP  
20 components based on the relative incentive compensation expense for each  
21 measure.



Line  
No.

1   **Q91. How did you quantify the benefit of achieving Target performance levels in**  
2       **the Customer Satisfaction measures?**

3   A91. The benefits of achieving the 2024 Target of 33 Net Promoter Score (NPS) are  
4       based on the expectation that improvements in the NPS score will result in fewer  
5       customer calls. The 2024 Target of 33 is expected to produce \$1.747 million of  
6       customer benefits based on avoided Company costs and customer costs.

7

8       While the total quantified benefits related to the Customer Satisfaction measure are  
9       less than the related expense, there can be little doubt that an emphasis among the  
10      Company's employees on improving the experiences customers have with the  
11      Company results in additional significant non-quantifiable benefits to both  
12      customers and the Commission.

13

14   **Q92. How did you determine the benefits of the Employee Engagement measure?**

15   A92. The quantifiable benefits of a highly engaged workforce are based on three critical  
16      dimensions identified by Gallup: absenteeism, productivity, and safety incidents.  
17      According to Gallup, a 0.1 improvement in the grand mean will result in a 3.1%  
18      reduction in absenteeism, a 1.8% increase in productivity, and a 3.8% reduction in  
19      safety incidents. Compared to the 80th percentile of Gallup survey results for all  
20      companies included in Gallup's database, the achievement of the 2024 Gallup  
21      Target will generate O&M savings of \$13.760 million, which is attributed  
22      exclusively to the AIP because the Employee Engagement measure is not included  
23      in the REP.

Line  
No.

1 **Q93. What are the expected benefits of the Company achieving Target level**  
2 **performance regarding the OSHA Recordable Incident Rate (RIR)?**

3 A93. The benefits of achieving the OSHA Recordable Incident Rate (RIR), and the  
4 Nuclear Total Industrial Safety Accident Events Target, are based on the estimated  
5 direct costs of non-fatal incidents of \$40,000, as developed by OSHA, as adjusted  
6 for inflation through 2023 and a study by Liberty Mutual that estimates the indirect  
7 cost of an OSHA recordable incident is about 3.0 times the direct costs, resulting  
8 in an estimated total cost of \$167,000 per incident, in current dollars. Based on  
9 Target level performance, relative to the Company's five-year average, this results  
10 in an estimated benefit of \$1.935 million, net of the savings capitalized. The  
11 benefits of achieving the OSHA RIR Target are allocated to all the other safety  
12 measures in proportion to the costs of each measure, as reflected on lines 27 through  
13 33 of Exhibit A-21, Schedule K6.

14

15 While the quantified savings of the safety related metrics are less than the related  
16 costs, much like the customer service-related measures, the benefits of maintaining  
17 an organizational focus on the safe operation of the Company's system for the  
18 benefit of its employees, customers, and the communities where the Company  
19 operates are undoubtedly substantial.

20

21 **Q94. How did you quantify the savings related to improvements in distribution**  
22 **system reliability?**

23 A94. Because there are no reliable means of computing the savings related to the duration  
24 of storm outages and CEMI4, the benefit of achieving the generation reliability  
25 performance Targets was calculated based on the Company achieving its 2024

Line  
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1 SAIDI excluding MEDs goal of 145 minutes compared to the five-year average of  
2 SAIDI excluding MEDs of 157 minutes, which represents a reduction of 12  
3 minutes. The derivation of the benefits to customers is based on the Interruptions  
4 Cost Estimation Calculator as developed by Nexant, Inc. and the Lawrence  
5 Berkeley National Lab. A reduction of 12 minutes in SAIDI excluding MEDs  
6 produces an annual customer benefit of \$54.934 million, which been allocated  
7 equally between the Storm Customers Restored within 48 Hours and CEMI4  
8 Percent of Customers measure, as reflected on lines 38 and 40 of Exhibit A-21,  
9 Schedule K6.

10

11 **Q95. Have you quantified the benefits of the Generation Availability measure?**

12 A95. No. The 2024 Generation Availability Target of 82.7% is the same as the four-year  
13 average of actual Generation availability of 82.7%. Accordingly, I have not  
14 quantified the customer benefits related to Generation Availability.

15

16 **Q96. What are the benefits of an increase in the Nuclear Annual On-Line Reliability**  
17 **Loss Factor (ORLF)?**

18 A96. The benefits of achieving the 2024 ORLF Target are based on a decrease in the  
19 ORLF at Fermi 2 from the four-year average of 2.83% to the 2024 Target of 0.78%.  
20 The savings computed are based on the differential between Fermi 2's marginal  
21 fuel costs and the average market price of avoided energy purchases combined with  
22 the value of increased capacity for a total annual savings of \$4.498 million. These  
23 savings are allocated to the Nuclear related operating measures included in the AIP  
24 and REP in proportion to the costs of each measure, as reflected in lines 44 through  
25 50 of Exhibit A-21, Schedule K6. Although the Electric and LLC nuclear

Line  
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1 generation measures reflect the Unit Capability Factor (UCF) measure, the only  
2 difference between the UCF and ORLF measure is that planned outages are  
3 included in the UCF.

4

5 **Q97. Have you quantified any additional savings related to the other Nuclear**  
6 **Generation measures included in the AIP and REP?**

7 A97. No. The Nuclear ORLF measure represents the only quantifiable benefits of the  
8 Company meeting its Target performance levels for Fermi 2. While there is  
9 indisputable value in the various specific measures within the other Nuclear  
10 measures, the benefits of Fermi 2 achieving the Nuclear ORLF Target has been  
11 attributed to the other AIP and REP Nuclear Operating Excellence measures.

12

13 **Q98. What is your conclusion regarding the cost effectiveness of the Company's**  
14 **incentive compensation plans?**

15 A98. As reflected on Exhibit A-21, Schedule K6, it is clear the quantified customer  
16 benefits of the Company achieving Target performance levels are substantially  
17 greater than the related expense.

18 Because the Company's overall employee compensation approximates the market,  
19 inclusive of incentive compensation, and the quantified customer benefits exceed  
20 the projected incentive compensation expense, the Company's total incentive  
21 compensation expense should be included in the revenue requirement adopted by  
22 the Commission in this proceeding as a reasonable and prudently incurred expense.

Line  
No.

1   **Q99. What was the Commission's directive regarding the measurement of the**  
2       **Company's weighted performance for the AIP and REP?**

3   A99. While the Commission correctly rejected the Attorney General's proposal to  
4       measure historical results for the Operating measures based on the binary method  
5       (i.e., a simple determination that each measure's performance was either at Target  
6       or below Target), in favor of the Company's weighted method, it requested the  
7       Company provide further explanation of the method used in determining those  
8       weighted results for the years 2019 through 2023 (Case No. U-21534, Order, p  
9       278).

10

11   **Q100. Have you prepared an exhibit that reflects the performance weighted results**  
12       **for the years 2019 through 2023?**

13   A100. Yes. Page one of Exhibit A-21, Schedule K7 provides the summary calculation of  
14       the weighted results of the Operating measures for the years 2019 through 2023,  
15       which is a reproduction of Exhibit A-35, Schedule Z1 from Case No. U-21534.  
16       Pages two through four of Exhibit A-21, Schedule K7 provides the detail for  
17       performance of each Operating measure related to DTE Electric, Nuclear  
18       Generation and DTE LLC for each of the years between 2019 and 2023 that  
19       supports the summary.

20

21   **Q101. How were the weighted results calculated for DTE Electric?**

22   A101. The calculation of the weighted results for DTE Electric is reflected on page two of  
23       Exhibit A-21, Schedule K7. Specifically, the actual performance for each  
24       Operating measure for the years 2019 through 2023 is reflected, which for the REP  
25       ranges between zero and 150% depending on whether the results for each measure

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1 were below Threshold (for which there would be no payout), at Threshold (where  
2 the payout would be 50%), at Target (where the payout would be 100%) or at  
3 Maximum (where the payout would be 150%). For the AIP, the payouts at  
4 Threshold are 25%, at Target are 100% and at Maximum at 175%. For the AIP  
5 applicable to executives, the payouts are the same as the AIP except with a payout  
6 at Maximum of 200%.

7

8 When the result for each Operating measure is between the performance levels, the  
9 payout is calculated based on an interpolation between the levels. That is, if actual  
10 results for the REP are halfway between the Threshold performance level and  
11 Target performance level, the actual payout would 75%, which is halfway between  
12 the Threshold payout of 50% and the Target payout of 100%.

13

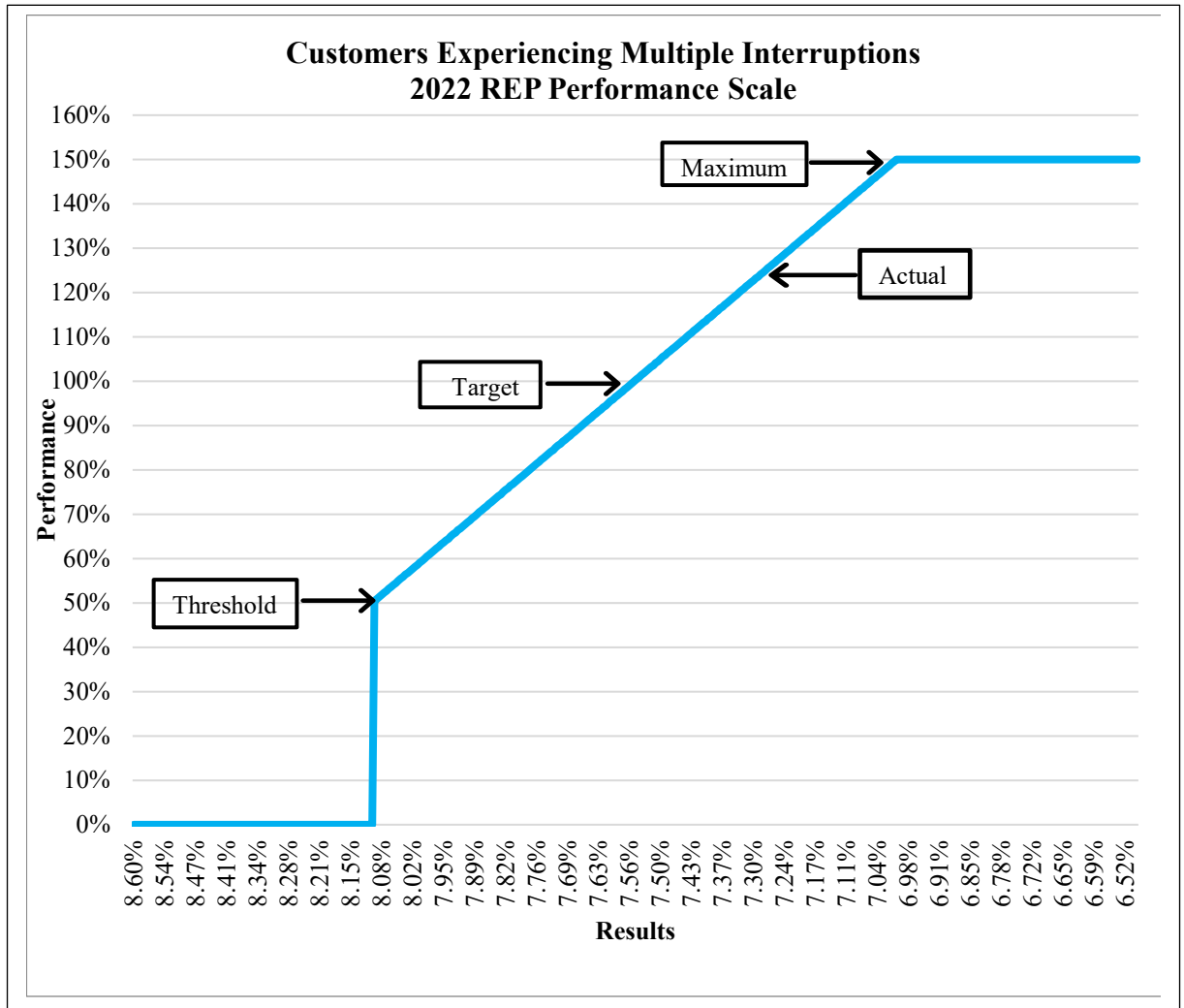
14 **Q102. Can you provide an example of how the actual results are determined that**  
15 **reflects the gradients of performance?**

16 A102. Yes. In 2022, the percentage of Customers Experiencing Multiple Interruptions of  
17 four or more (CEMI4) Threshold performance level was 8.10%, the Target  
18 performance level was 7.55% and the Maximum performance level was 7.00%.  
19 The actual result in 2022 of 7.29% resulted in the REP performance being 123.6%.  
20 The possible distribution of performance levels for this measure in 2022 are  
21 reflected in the chart in Table 3.

Line  
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1

Table 3



2

3 The same methodology is used for all the Operating measures reflected for the other  
4 measures on Exhibit A-21, Schedule K7, pages two through four.

5

6 **Q103. How are these performance levels aggregated?**

7 A103. The performance results of the Operating measures are then summed and divided  
8 by the number of measures for each year. For example, on page two of Exhibit  
9 A21, Schedule K7, the sum of DTE Electric's 2022 performance results for all the

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1 REP Operating measures is 637%, (as reflected in column (k), line 42) which is  
2 divided by eight, which is the number of REP measures in 2022, (as reflected in  
3 column (k), line 44. This results in an average performance of 79.6% for the 2022  
4 REP Operating measures, as shown in column (k), line 46 on page two of Exhibit  
5 A-21, Schedule K7.

6

7 The same methodology is used for all the Operating measures reflected for the other  
8 measures on Exhibit A-21, Schedule K7, pages two through four.

9

10 **Q104. How are the performance results summarized on Exhibit A-21, Schedule K7?**

11 A104. The Average Performance reflected on line 11 of Exhibit A-21, Schedule K7, page  
12 one, represents the average of DTE Electric's Operating measures for each year for  
13 all plans. Specifically, the average performance of 79.6% for the REP in 2022,  
14 described above, is reflected on line 11, column (q) on page one of Exhibit A-21,  
15 Schedule K7. All other performance levels reflected on page one of Exhibit A-21,  
16 Schedule K7 are similarly derived from the supporting detail reflected on pages two  
17 through four of Exhibit A-21, Schedule K7.

18

19 **Q105. What is the Company's overall performance in the Operating measures for**  
20 **the years 2019 through 2023 that reflects the gradients of performance?**

21 A105. The average performance results for the years 2019 through 2023 was 79.3% for  
22 the AIP, 81.5% for the Executive AIP and 69.2% for the REP for a combined simple  
23 average of 76.7%.

24

25 **Q106. What other information is reflected on page one of Exhibit A-21, Schedule K7?**



Line  
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1     A106. In addition to the summary of the performance results, page one of Exhibit A-21,  
2             Schedule K7 also summarizes the number of Operating measures for each year  
3             based on whether the actual results were below Threshold, between Threshold and  
4             Target, at Target, between Target and Maximum and at Maximum, consistent with  
5             the presentation used in Case No. U-21534.

6

7     **Q107. Does this complete your direct testimony?**

8     A107. 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-21860

QUALIFICATIONS  
AND  
DIRECT TESTIMONY  
OF  
THERESA M. UZENSKI

**DTE ELECTRIC COMPANY**  
**QUALIFICATIONS AND DIRECT TESTIMONY OF THERESA M. UZENSKI**

Line  
No.

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

2   A1.   My name is Theresa M. Uzenski. I am employed by DTE Energy Corporate  
3       Services, LLC, a subsidiary of DTE Energy Company (DTE Energy). My business  
4       address is One Energy Plaza, Detroit, MI 48226.

5

6   **Q2.   On whose behalf are you testifying?**

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

8

9   **Q3.   What is your educational background?**

10   A3.   I have a Bachelor of Science in Accounting from the University of Detroit and a  
11       Master of Business Administration with a concentration in Finance from Wayne  
12       State University.

13

14   **Q4.   What is your work experience and what position do you currently hold at DTE**  
15       **Energy?**

16   A4.   I have worked for DTE Energy or one of its affiliated regulated utilities for over  
17       thirty-five years in various accounting, finance, and management positions. I am  
18       currently the Manager of Regulatory Accounting for DTE Electric Company and  
19       DTE Gas Company.

20

21   **Q5.   Do you hold any certifications or are you a member of any professional**  
22       **organization?**

Line  
No.

1 A5. I am a Certified Management Accountant, a member of the Institute of Management  
2 Accountants, and a member of the Corporate Accounting Committee of the Edison  
3 Electric Institute and American Gas Association.

4  
5 **Q6. What are your current duties and responsibilities?**

6 A6. As Manager of Regulatory Accounting, I am responsible for the development and  
7 management of regulatory accounting policies and practices and supporting  
8 regulatory filings. My department analyzes the accounting implications of new  
9 legislation and Michigan Public Service Commission (Commission or MPSC)  
10 orders and provides expert testimony on accounting issues and financial projections  
11 in various proceedings before the MPSC. We research and establish accounting  
12 policies and assist the accounting operations departments with implementation. My  
13 department also supports other Company expert witnesses in various proceedings  
14 before the MPSC by preparing financial exhibits and other financial analyses.

15  
16 **Q7. Have you previously sponsored testimony before the Michigan Public Service**  
17 **Commission?**

18 A7. I have sponsored testimony in the following cases:  
19 U-11222 Michigan Consolidated Gas Company (MichCon) Depreciation  
20 U-13898 MichCon UETM  
21 U-14702 Detroit Edison 2006 PSCR Plan  
22 U-15160 Detroit Edison Enhanced Security Cost Recovery  
23 U-15244 Detroit Edison Choice Incentive Mechanism Reconciliation  
24 U-15259 Detroit Edison Pension Equalization Mechanism  
25 U-15417-R Detroit Edison Pension Equalization Mechanism

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|    |            |                                                           |
|----|------------|-----------------------------------------------------------|
| 1  | U-15806-EO | Detroit Edison Energy Optimization                        |
| 2  | U-15768    | Detroit Edison UETM                                       |
| 3  | U-15890    | MichCon Energy Optimization                               |
| 4  | U-16009    | Complaint Case against Detroit Edison                     |
| 5  | U-16246-R  | Detroit Edison 2009 RETM Reconciliation                   |
| 6  | U-16246-R  | Detroit Edison 2010 RETM Reconciliation                   |
| 7  | U-16356    | Detroit Edison 2009 REP Reconciliation                    |
| 8  | U-16472    | Detroit Edison 2010 Rate Case                             |
| 9  | U-16574    | Detroit Edison 2010 UETM Reconciliation                   |
| 10 | U-16582    | Detroit Edison 2014 REP Plan                              |
| 11 | U-16769    | MichCon Depreciation                                      |
| 12 | U-16952    | Detroit Edison 2014 CIM Reconciliation                    |
| 13 | U-16956    | Detroit Edison 2014 RETM Reconciliation                   |
| 14 | U-16964    | Detroit Edison 2014 UETM Reconciliation                   |
| 15 | U-17302    | DTE Electric Company 2017 REP Plan Update                 |
| 16 | U-17437    | DTE Electric Company Transitional Cost Recovery Mechanism |
| 17 | U-17767    | DTE Electric Company 2014 Rate Case                       |
| 18 | U-17999    | DTE Gas Company 2015 Rate Case                            |
| 19 | U-18014    | DTE Electric Company 2018 Rate Case                       |
| 20 | U-18122    | DTE Electric Company Customer 360 Program Accounting      |
| 21 | U-18255    | DTE Electric Company 2017 Rate Case                       |
| 22 | U-18419    | DTE Electric Company Certificates of Necessity            |
| 23 | U-18999    | DTE Gas Company 2018 Rate Case                            |
| 24 | U-20106    | DTE Gas Company Tax Cut & Jobs Act – Credit A             |
| 25 | U-20105    | DTE Electric Company Tax Cut & Jobs Act – Credit A        |

Line  
No.

|    |         |                                                    |
|----|---------|----------------------------------------------------|
| 1  | U-20162 | DTE Electric Company 2018 Rate Case                |
| 2  | U-20298 | DTE Gas Company Tax Cut & Jobs Act – Credit C      |
| 3  | U-20561 | DTE Electric Company 2019 Rate Case                |
| 4  | U-20642 | DTE Gas Company 2019 Rate Case                     |
| 5  | U-20940 | DTE Gas Company 2021 Rate Case                     |
| 6  | U-21015 | DTE Electric Company 2021 Securitization           |
| 7  | U-20836 | DTE Electric Company 2022 Rate Case                |
| 8  | U-21193 | DTE Electric Company 2022 Integrated Resource Plan |
| 9  | U-21297 | DTE Electric Company 2023 Rate Case                |
| 10 | U-21291 | DTE Gas Company 2024 Rate Case                     |
| 11 | U-21534 | DTE Electric Company 2024 Rate Case                |

Line  
No.

1 **Purpose of Testimony**

2 **Q8. What is the purpose of your testimony?**

3 A8. The purpose of my testimony is to support DTE Electric's financial statements for  
4 the historical test year ended December 31, 2023, the interim forecast period and a  
5 twelve-month projected test period ending December 31, 2026, with certain  
6 adjustments necessary for presenting the financial information in the appropriate  
7 format for ratemaking purposes. My testimony supports the development of the  
8 projected test year adjusted Electric operating income based on forecasted changes  
9 from the normalized historical Electric operating income. I will discuss how costs  
10 recovered from other mechanisms are excluded from the financial statements in this  
11 case including Renewable Energy Program (REP), Energy Waste Reduction  
12 (EWR), Investment Recovery Mechanism (IRM) and Power Supply Cost Recovery  
13 (PSCR). I will support the Corporate Staff Group (CSG) capital and Operations  
14 and Maintenance (O&M) expenses for the historical and forecasted periods and  
15 explain the function of this group including the method for allocating costs to DTE  
16 Electric and other DTE subsidiaries through the Shared Asset charge.

17

18 I will also explain various accounting treatments. This includes the Monroe  
19 regulatory asset and amortization over 15 years. Witness Vangilder supports the  
20 revenue requirement. I explain a proposal to defer and amortize investment tax  
21 credits related to a battery storage asset. I request regulatory asset treatment for  
22 certain debt financing costs and merchant fees.

23

24 **Q9. What exhibits are you sponsoring in this proceeding?**

25 A9. I am supporting the following exhibits for the historical period:

Line  
No.

| <u>1</u> | <u>Exhibit</u> | <u>Schedule</u> | <u>Description</u>                                 |
|----------|----------------|-----------------|----------------------------------------------------|
| 2        | A-2            | B2              | Historical Utility Plant                           |
| 3        | A-2            | B3              | Historical Depreciation Reserve                    |
| 4        | A-2            | B4              | Historical Working Capital                         |
| 5        | A-2            | B5              | Historical 13-Month Average Adjusted Balance       |
| 6        |                |                 | Sheet with Classifications                         |
| 7        | A-2            | B5.1            | Historical Year-End Adjusted Balance Sheet with    |
| 8        |                |                 | Classifications                                    |
| 9        | A-2            | B6              | Historical Adjusted Balance Sheet – Year Ended and |
| 10       |                |                 | 13-Month Average                                   |
| 11       | A-2            | B6.1            | Historical Year-End Adjusted Balance Sheet         |
| 12       | A-2            | B6.2            | Historical 13-Month Average Adjusted Balance       |
| 13       |                |                 | Sheet                                              |
| 14       | A-2            | B7              | ARO & Nuclear Decommissioning Trust Fund           |
| 15       | A-3            | C1              | Historical Adjusted Net Operating Income           |
| 16       | A-3            | C1.1            | Adjustments to Historical Net Operating Income     |
| 17       | A-3            | C3              | Historical Operating Revenue                       |
| 18       | A-3            | C4              | Historical Fuel and Purchased Power                |
| 19       | A-3            | C5              | Historical Operation and Maintenance Expenses      |
| 20       | A-3            | C6              | Historical Depreciation and Amortization Expenses  |
| 21       | A-3            | C11             | Historical Allowance for Funds Used During         |
| 22       |                |                 | Construction                                       |
| 23       | A-3            | C14             | Historical Corporate Memberships Adjustment        |
| 24       | A-3            | C15             | Historical Advertising Adjustment                  |
| 25       | A-3            | C16             | Historical MERC Net Operating Income               |



Line  
No.

|   |     |     |                                                  |
|---|-----|-----|--------------------------------------------------|
| 1 | A-3 | C17 | Historical Power Supply Cost Recovery Items      |
| 2 | A-3 | C18 | Eliminate Nuclear Surcharge                      |
| 3 | A-3 | C19 | Historical Executive Incentive Compensation      |
| 4 |     |     | Adjustment                                       |
| 5 | A-3 | C20 | Historical Employee Incentive Plan Normalization |
| 6 |     |     | Adjustment                                       |
| 7 | A-3 | C21 | Historical Weather Normalization Adjustment      |
| 8 |     |     |                                                  |

9 I am also supporting the following exhibits for the projected test year:

|    |                |                 |                                                     |
|----|----------------|-----------------|-----------------------------------------------------|
| 10 | <u>Exhibit</u> | <u>Schedule</u> | <u>Description</u>                                  |
| 11 | A-12           | B2              | Projected Utility Plant                             |
| 12 | A-12           | B3              | Projected Depreciation Reserve                      |
| 13 | A-12           | B4              | Projected Working Capital                           |
| 14 | A-12           | B4.1            | Projected Average Balance Sheet with Classification |
| 15 | A-12           | B4.2            | Projected Balance Sheet                             |
| 16 | A-12           | B4.3            | Common Equity Reconciliation                        |
| 17 | A-12           | B4.4            | Monroe Regulatory Asset - Projected Balance         |
| 18 | A-12           | B4.5            | Monroe Regulatory Asset - Calculation               |
| 19 | A-12           | B5              | Projected Capital Expenditures – Summary            |
| 20 | A-12           | B5.8            | Projected Capital Expenditures – Corporate Staff    |
| 21 | A-13           | C1              | Projected Net Operating Income                      |
| 22 | A-13           | C1.1            | Projected Net Operating Income Adjustments          |
| 23 | A-13           | C3              | Projected Operating Revenue                         |
| 24 | A-13           | C5              | Projected O&M Expense – Summary                     |
| 25 | A-13           | C5.6.2          | ADMS Regulatory Asset Amortization                  |

Line  
No.

|    |      |         |                                                  |
|----|------|---------|--------------------------------------------------|
| 1  | A-13 | C5.9.1  | TEP Regulatory Asset Amortization                |
| 2  | A-13 | C5.9.3  | ACPP and TOD Regulatory Asset Amortization       |
| 3  | A-13 | C5.10   | Projected Administrative and General Expenses    |
| 4  | A-13 | C5.10.1 | Incentive Deferral Mechanism                     |
| 5  | A-13 | C5.15   | Inflation Factors                                |
| 6  | A-13 | C5.17   | PERC (Nuclear Projects) Regulatory Asset         |
| 7  |      |         | Amortization                                     |
| 8  | A-13 | C6      | Projected Depreciation and Amortization Expense  |
| 9  | A-13 | C11     | Projected Allowance for Funds Used During        |
| 10 |      |         | Construction                                     |
| 11 | A-13 | C11.1   | AFUDC Ratemaking Adjustment                      |
| 12 | A-13 | C12     | Projected Amortization of the Loss on Reacquired |
| 13 |      |         | Debt                                             |
| 14 | A-13 | C13     | Projected Other (Income) / Deductions            |

15

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

17 A10. Yes, they were.

18

19 **Q11. How were your exhibits prepared?**

20 A11. My team, under my direction, uses an Excel model to create historical and projected  
 21 balance sheets and income statements, and the supporting exhibits. We also have  
 22 models to capture historical and projected O&M and capital expenditures. The  
 23 O&M and capital models feed into the financial statement model. Our models start  
 24 with historical financial information from the MPSC Annual Report on Form P-  
 25 521. I calculate most of the rate case normalizations and adjustments to the

Line  
No.

1 historical balance sheet and income statement, but other Company witnesses  
2 calculate the adjustments to the O&M and capital expenditures for the business unit  
3 costs that they support. In addition, Company Witnesses Vangilder and  
4 Wisniewski support certain adjustments to interest and taxes. I support the O&M  
5 and capital costs for the Corporate Staff Group other than Information Technology  
6 (IT).

7

8 After the normalizations and adjustments are made to the historical period, I use  
9 the adjusted amounts to develop the financial statements for the projected period.  
10 Again, the witnesses supporting their business unit costs provide the known and  
11 measurable adjustments to O&M expenses and the details for capital expenditures.  
12 Sales revenue and fuel and purchased power are calculated by Company Witness  
13 Willis. Company Witness Wisniewski calculates income and property taxes. The  
14 data provided by these witnesses is captured in my models to create the  
15 consolidated financial statements for the projected period. Witness Vangilder then  
16 uses my projected financial statement data to calculate the revenue deficiency.

17

18 **Q12. What is the impact to the historical and projected income statements from the**  
19 **Transitional Recovery Mechanism (TRM)?**

20 A12. The transition of the City of Detroit Public Lighting Department's (PLD) electric  
21 retail service to DTE Electric was completed in 2022. A final TRM reconciliation  
22 was filed on October 31, 2022, in Case No. U-21307 covering the period January  
23 1, 2021 through October 31, 2022. On July 26, 2023 the Commission issued an  
24 Order approving the final reconciliation and ratemaking for the TRM. Consistent  
25 with prior rate cases, I have removed the TRM surcharge revenue and the related

Line  
No.

1 regulatory asset because they are addressed in the TRM reconciliation process.  
2 Please refer to Exhibit A-2, Schedule B6.1, column (k). The TRM regulatory asset  
3 on line 43 represents costs incurred before November 2022. It is being recovered  
4 via a separate surcharge through February 2024. The exhibits include the sales  
5 revenue from PLD customers along with the related base fuel and purchased power  
6 expense. Please see Workpaper TMU-6. The TRM elimination in the instant case  
7 reflects only the surcharge revenue and O&M costs that will not recur.

8

9 **Historical Test Year**

10 **Q13. What information are you providing regarding the Historical Test Year ended**  
11 **December 2023?**

12 A13. For the historical test year ended December 2023, I am providing the balance sheet  
13 and net operating income (NOI) information with certain adjustments that are  
14 necessary to present the financial information in the appropriate ratemaking format.  
15 The adjusted historical financial statements are the starting point in creating the  
16 financial statements for the projected test period.

17

18 **Historical Balance Sheet**

19 **Q14. What historical test year balance sheet information are you providing?**

20 A14. Exhibit A-2, Schedules B2 and B3 provide the historical utility plant and  
21 depreciation reserves, respectively. Schedule B4 provides the historical 13-month  
22 average for working capital. Schedule B5 classifies the historical balance sheet  
23 information into the categories of net plant, working capital, and the various  
24 financing components adjusted to use a 13-month average. Schedule B5.1 provides  
25 the same classifications based on a historical year-end balance.

Line  
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1

2

Exhibit A-2, Schedule B6 shows the historical balance sheet amounts on a historical year-end and 13-month average incorporating the adjustments detailed on schedules B6.1 and B6.2. Schedule B6.1 contains the historical test year balance sheet information on December 31, 2023. Schedule B6.2 is a 13-month average balance sheet for the periods December 2022 through December 2023. The columns for both schedules detail the same types of adjustments. Schedules B6.1 and B6.2, column (b) values are from the MPSC Annual Report on Form P-521.

9

10 **Q15. Does the historical balance sheet include the values for MERC?**

11

A15. Column (c) adds the balance sheet values for the Midwest Energy Resources Company (MERC), a wholly owned subsidiary of DTE Electric involved in low-sulfur western coal storage and transshipment operations. Pursuant to the Commission's Order in Case No. U-5108, capital costs incurred by MERC, including depreciation and property taxes, administrative expenses, income tax, interest, and return on rate base are to be considered in the Company's main electric ratemaking process. However, MERC is targeted to cease operations during 2026 when the Belle River Power Plant discontinues generation using coal. In Case No. U-21534, the Company proposed that any net assets remaining at MERC after operations cease be securitized (along with the Belle River coal assets). Therefore, for simplicity, I have excluded the MERC values from the historical balance sheet instead of forecasting changes and then eliminating the effects in the projected financial statements, with the exception of inter-company receivables and payables, and deferred income taxes. Column (d) is the consolidated balance on which I base my adjustments.

25

Line  
No.

1   **Q16. Why did you include MERC inter-company receivables and payables, and**  
2       **deferred income taxes in the consolidated balance sheet?**

3   A16. The MERC inter-company receivable and payable balances offset the related inter-  
4       company balances at DTE Electric included in column (b), so they need to be  
5       included to get the correct consolidated amounts. The deferred income taxes were  
6       not eliminated because I assumed that when MERC's plant assets are securitized,  
7       the related deferred taxes would remain with DTE Electric. In recent securitization  
8       transactions, the Commission ordered that the plant asset be removed on a gross  
9       basis, with no impact to accumulated deferred income taxes.

10

11   **Q17. Why is there a reduction to long-term debt and equity for MERC in column**  
12       **(c)?**

13   A17. When the MERC assets are securitized, the proceeds will be used to pay the inter-  
14       company balances owed to DTE Electric. DTE Electric will then reduce debt and  
15       equity in equal amounts.

16

17   **Q18. What adjustments are you making to the consolidated historical period**  
18       **financial statements?**

19   A18. Consistent with the treatment in past cases, I am reclassifying certain items,  
20       removing non-utility items, and removing balances that are being recovered or  
21       refunded via other mechanisms or surcharges including EWR, REP, IRM, and  
22       PSCR. For each regulatory asset and liability amount excluded, I removed the  
23       related Accumulated Deferred Federal Income Tax (ADFIT) with the remaining  
24       capital removed from short-term debt, as these items are considered temporary  
25       working capital requirements. I am removing the Combined Operating License

Line  
No.

1 (COL) for ratemaking purposes. Additionally, I am removing the Tree Trim  
2 Regulatory Asset and Tier 2 plant assets that have been securitized.

3

4 The adjustments are shown on the balance sheets on Exhibit A-2, Schedules B6.1  
5 and B6.2, columns (e) through (l). Since I used the adjusted historical period to  
6 build the forecast, I did not have to make these same adjustments to the projected  
7 period. I will discuss each adjustment below.

8

9 **Q19. What is the adjustment for taxes?**

10 A19. Column (e) nets the Accumulated Deferred Income Tax Asset on line 67 and the  
11 Investment Tax Credit (ITC) on line 120, with the Accumulated Deferred Income  
12 Tax Liability on line 119. The ITC amount reflected in the reclassification is  
13 supported by Witness Wisniewski.

14

15 **Q20. What is the adjustment for Tier 2 Plants?**

16 A20. The St. Clair and Trenton Channel "Tier 2" coal plants were retired in 2022 before  
17 the end of their respective lives. In the June 22, 2023 Order in Case No. U-21338,  
18 the Commission approved the securitization of \$594.1 million of St. Clair and  
19 Trenton Channel net plant. The Commission also granted approval to classify these  
20 costs as a regulatory asset. While the regulatory asset was removed from the 2023  
21 balance sheet with the securitization transaction, the balance in 2022 impacted the  
22 13-month average on Exhibit A-2, Schedule B6.2. Therefore, in column (f), I  
23 reduced the Tier 2 Plants regulatory asset by \$502.7 million, which were the  
24 combined balances of St. Clair and Trenton Channel approved for securitization.  
25 The related capitalization of 50% debt and 50% equity is also removed. This

Line  
No.

1 approach is consistent with the Commission's Order in the 2023 Securitization  
2 Case No. U-21338, which required the balances related to the St. Clair and Trenton  
3 Channel generation sites to be removed on a gross basis, with no impact to  
4 accumulated deferred income taxes.

5

6 **Q21. What is the elimination for Tree Trim?**

7 A21. The Commission authorized the Company's Tree Trim surge program, allowing for  
8 regulatory asset treatment of costs above an approved base amount in O&M. The  
9 regulatory asset is not included in rate base because the balance through June 2021  
10 of \$156.9 million was securitized pursuant to the Commission's June 23, 2021  
11 Order in Case No. U-21015. Additionally, the Company is planning a future  
12 securitization of the Tree Trim regulatory asset once the balance is large enough,  
13 as described by Witness Lepczyk. Therefore, I removed the historical regulatory  
14 asset and related capitalization of 50% debt and 50% equity in column (g). The  
15 revenue requirement for the forecasted Tree Trim Surge regulatory asset, which  
16 represents the tree trim costs not yet securitized, is separately calculated and  
17 supported by Witness Vangilder on his Exhibit A-11, Schedule A1.1.

18

19 **Q22. What is the adjustment for the COL?**

20 A22. Per the Commission's Orders in Case Nos. U-18014 and U-17767, the COL asset  
21 is being amortized over twenty years, but the remaining balance must be excluded  
22 from rate base. Therefore, in column (h) I have removed both the COL asset  
23 reflected on the books of DTE Electric and the related capitalization of debt and  
24 equity at 50% each.



Line  
No.

1   **Q23. What are the adjustments for programs and recovery mechanisms in columns**  
2       **(i) through (l)?**

3   A23. Column (i) eliminates DTE Electric's EWR program. Column (j) eliminates the  
4       REP, except for the regulatory liability, column (k) eliminates the TRM related to  
5       the conversion of the City of Detroit's PLD customers to DTE Electric, and column  
6       (l) eliminates the IRM. The associated debt and equity eliminations are consistent  
7       with the capital structures authorized by the Commission for each program.

8

9   **Q24. If the REP is excluded from base rates, then why are you not eliminating the**  
10       **associated regulatory liability?**

11   A24. The regulatory liability generated from the REP program is not eliminated because  
12       it is being used as a source of financing for DTE Electric's general rate base.  
13       Therefore, I have reclassified the balance out of the regulatory liability on line 108  
14       and reflected it as short-term debt on line 96.

15

16   **Q25. Why are you showing the REP regulatory liability as a source of financing for**  
17       **general rate base instead of REP rate base?**

18   A25. Consistent with the Commission's Order in Case No. U-15806 the return embedded  
19       in the REP surcharge reflects DTE Electric's approved cost of capital, primarily  
20       long-term debt, and equity. However, because the REP revenue requirement was  
21       collected in a surcharge separate from base rates, the remaining liability generated  
22       from the previous surcharge is available to reduce DTE Electric's other short-term  
23       debt, as approved by the Commission in Case No. U-15806.

Line  
No.

1   **Q26. If DTE Electric is using the regulatory liability as a source of financing, then**  
2       **how are DTE Electric's customers compensated?**

3   A26. The REP revenue requirement and surcharge is reduced by interest accrued on the  
4       regulatory liability.

5  
6   **Q27. What accounting adjustments are reflected in the Company's financial**  
7       **presentation for the historical test year in this case?**

8   A27. This rate case reflects adjustments for Accounting Standards Codification (ASC)  
9       842, Accounting for Right-of-Use Assets (Operating Leases); ASC 410,  
10      Accounting for Asset Retirement Obligations; and ASC 715, Employers'  
11      Accounting for Defined Benefit Pension and Other Postretirement Plans, because  
12      the accounting impacts are excluded from the revenue requirement.

13  
14   **Q28. What is the adjustment for leases?**

15   A28. The Financial Accounting Standards Board issued ASC 842, which requires  
16      operating leases to be recognized on the balance sheet effective for DTE Electric in  
17      2019. GAAP financial statements now include operating lease right-of-use assets  
18      and liabilities. The Uniform System of Accounts does not include balance sheet  
19      accounts for operating leases. The FERC ruled that the new lease accounting  
20      standard cannot impact ratemaking, and operating lease expense must continue to  
21      be based on actual amounts paid and be recorded as rent expense. I eliminated the  
22      operating lease asset and related liabilities (short-term and long-term) in column  
23      (m) to ensure there is no impact to ratemaking resulting from this new accounting  
24      standard. Additionally, in column (m) I eliminated a deferred gain on the sale of  
25      land associated with a prepaid lease for a parking structure that is amortized below

Line  
No.

1 the line. In prior cases, the Commission ordered that this item was to be excluded  
2 from rate base.

3

4 **Q29. What is the adjustment for asset retirement obligations?**

5 A29. The accounting for asset retirement obligations (ARO) results in timing differences  
6 in the recognition of legal asset retirement costs for accounting purposes compared  
7 to the recognition of amounts the Company is currently recovering in rates. ARO  
8 accounting requires an up-front accrual for future legal removal costs as a liability.  
9 Utility accounting recognizes the removal obligation in accumulated depreciation  
10 and accrues it through depreciation expense over the life of the asset. The timing  
11 differences are deferred under ASC 980, Regulated Operations. The ARO liability  
12 is offset by a corresponding net plant Asset Retirement Cost and a regulatory asset,  
13 which results in no impact on the revenue requirements in this case. A regulatory  
14 asset does not offset the incremental liability related to the non-utility Fermi 1 site.

15

16 To ensure that there is no impact on revenue requirements from ARO accounting  
17 in the forecast years, I have removed all 2023 regulated balance sheet impacts on  
18 Exhibit A-2, Schedules B6.1 and B6.2, column (n). I also removed the ARO for  
19 Fermi 1 and the related decommissioning trust fund asset. In addition, I have  
20 removed the decommissioning obligation and related trust fund assets for Fermi 2.  
21 The details of the balance sheet eliminations are shown in Exhibit A-2, Schedule  
22 B7.

23

24 **Q30. What are the ARO and Nuclear Decommissioning Trust Fund eliminations**  
25 **shown on Exhibit A-2, Schedule B7?**

Line  
No.

1 A30. Exhibit A-2, Schedule B7 shows the components of ARO accounting as well as  
2 nuclear decommissioning that are included in the unadjusted historical balance  
3 sheet. The removal of the ARO items is consistent with DTE Electric's presentation  
4 that the Commission has reviewed and accepted in all the Company's rate cases  
5 beginning with Case No. U-15244.

6

7 **Q31. Why did you eliminate the Fermi 2 Nuclear Decommissioning Trust Fund?**

8 A31. The assets and related liabilities for Fermi 2 decommissioning net to zero with no  
9 impact to rate base. For transparency, I removed all the line items from the  
10 historical balance sheet consistent with the Company's presentation that was  
11 reviewed and accepted by the Commission in its rate cases beginning with Case  
12 No. U-18014.

13

14 **Q32. Can you explain the adjustment for benefit plans?**

15 A32. ASC 715 requires the recognition of the unfunded liabilities for defined benefit  
16 pension and other post-retirement plans with a charge to other comprehensive  
17 income within equity. DTE Electric recorded a regulatory asset in place of the  
18 charge to other comprehensive income because the costs are included in rates  
19 consistent with when the expense is recognized in the income statement. Since the  
20 liability and offsetting regulatory asset results in no change to revenue  
21 requirements, Exhibit A-2, Schedules B6.1 and B6.2, column (o) eliminates the  
22 2023 balance sheet impacts related to ASC 715. This treatment is also consistent  
23 with DTE Electric's presentation in all its rate cases starting with Case No. U-  
24 15244.

Line  
No.

1 **Q33. What are the working capital normalizations in column (p)?**

2 A33. Customer Accounts Receivable is adjusted to remove the impact of weather.  
3 Accounts Receivable from Associated Companies is adjusted to remove non-utility  
4 balances. These adjustments increase working capital by \$11.9 million on Schedule  
5 B6.1 (year-end) and by \$8.4 million on Schedule B6.2 (13-month average).

6

7 **Q34. Why are you eliminating the items in column (q), Other?**

8 A34. Column (q) eliminates an asset for PSCR (\$54.8 million) that is reconciled in the  
9 PSCR mechanism, and a \$600,000 regulatory liability related to the Tree Trim  
10 surge that was netted against the Tree Trim regulatory asset in 2024, as approved  
11 in Case No. U-21128. It eliminates a software maintenance prepaid asset and the  
12 offsetting liability that net to zero in working capital. It reclassifies a current lease  
13 payable out of short-term debt to deferred credits. It eliminates a tax reserve that  
14 is recognized only for GAAP purposes and eliminates affiliate Notes  
15 Receivable/Notes Payable that are assumed settled in the projected period. It  
16 removes equity investments in affiliates. It also removes non-utility amounts from  
17 DTE Electric's consolidated balance sheets including the Detroit Investment Fund.  
18 In prior cases, the Commission ordered that these items are to be excluded from  
19 rate base. Column (q) also reflects the write-off of certain plant balances resulting  
20 from the Order in Case No. U-21534, totaling \$3.8 million for which the Company  
21 is no longer seeking recovery (primarily related to Information Technology  
22 investments).

23

24 **Q35. What information is contained in column (r), Total Electric, on Exhibit A-2,**  
25 **Schedule B6.1?**

Line  
No.

1 A35. Column (r), "Total Electric" represents the DTE Electric balance sheet as of  
2 December 31, 2023, after adjustments. This Total Electric December 2023 balance  
3 sheet is used by Witness Vangilder in determining DTE Electric's year-end  
4 historical rate base and capitalization.

5  
6 **Q36. What information is contained in column (r), Total Electric, on Exhibit A-2,**  
7 **Schedule B6.2?**

8 A36. Column (r), "Total Electric", represents the DTE Electric balance sheet after the  
9 adjustments previously discussed. These 2023 Total Electric 13-month average  
10 balances are used by Witness Vangilder in determining DTE Electric's average  
11 historical rate base and capitalization.

12  
13 **Q37. What information is shown on Exhibit A-2, Schedule B6?**

14 A37. Exhibit A-2, Schedule B6, page 1 is the Assets and Other Debits portion, and page  
15 2 is the Liabilities and Other Credits portion of the DTE Electric Adjusted Balance  
16 Sheet for December 2023. Column (b) reflects December 31, 2023 balances while  
17 column (c) represents the 13-month average balances. Both columns are carried  
18 from column (r) of Exhibit A-2, Schedules B6.1 and Schedule B6.2, respectively.

19  
20 **Historical Income Statement**

21 **Q38. What information are you supporting on Exhibit A-3, Schedules C1 and C1.1,**  
22 **Adjustments to Historical Net Operating Income (NOI)?**

23 A38. On Exhibit A-3, Schedules C1 and C1.1, DTE Electric's Adjusted Net Operating  
24 Income (NOI) for the year ended December 31, 2023 was determined by starting  
25 with the financial information reported on the Company's MPSC Annual Report

Line  
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1 Form P-521, page 114. Then I adjusted the reported financial information for  
2 certain exclusions and inclusions to get to a rate case filing level. The rate case  
3 filing level was further adjusted by normalizations to remove unusual, temporary  
4 or one-time events. I support the adjustments to NOI on Exhibit A-3, Schedule  
5 C1.1, except for lines 26 and 28 supported by Company Witness Guillaumin; line  
6 27 supported by Company Witness Davis; line 29 supported by Company Witness  
7 Kryscynski; line 30 supported by Company Witness Sparks; line 31 supported by  
8 Company Witness Foley; line 38 supported by Company Witnesses Cooper and  
9 Fix; and lines 44 and 45, which are supported by Witness Vangilder.

10

11 **Q39. What information is displayed in Exhibit A-3, Schedule C3, Historical**  
12 **Operating Revenue?**

13 A39. Exhibit A-3, Schedule C3 provides the amounts as reported on MPSC Annual  
14 Report Form P-521 for retail, wholesale, refund provisions and miscellaneous  
15 revenues, underlying the total revenue for the 12-month period ended December  
16 31, 2023 and is carried forward to line 1, column (c), of Exhibit A-3, Schedule  
17 C1.1.

18

19 **Q40. What is the purpose of Exhibit A-3, Schedule C4, Historical Fuel and**  
20 **Purchased Power?**

21 A40. Exhibit A-3, Schedule C4 provides the amounts as reported on the MPSC Annual  
22 Report Form P-521 for various accounts associated with power supply expenses for  
23 the 12-month period ended December 31, 2023 and is carried forward to Exhibit  
24 A-3, Schedule C1.1, column (d), line 1.

Line  
No.

1 **Q41. What information is displayed in Exhibit A-3, Schedule C5, Historical**  
2 **Operation and Maintenance Expense?**

3 A41. Exhibit A-3, Schedule C5 provides the amounts as reported on the MPSC Annual  
4 Report Form P-521 for operation and maintenance expenses adjusted to exclude  
5 fuel and purchased power expense for the 12-month period ended December 31,  
6 2023 and is carried forward to Exhibit A-3, Schedule C1.1, column (e), line 1.

7

8 **Q42. What information is displayed in Exhibit A-3, Schedule C6, Historical**  
9 **Depreciation and Amortization Expenses?**

10 A42. Exhibit A-3, Schedule C6 provides the amounts as reported on the MPSC Annual  
11 Report Form P-521 for various accounts related to depreciation and amortization  
12 expense for the 12-month period ended December 31, 2023, and is carried forward  
13 to Exhibit A-3, Schedule C1.1, column (f), line 1.

14

15 **Q43. What information is contained on line 1 of Exhibit A-3, Schedule C1.1?**

16 A43. Net Operating Income of \$1,126.4 million is on line 1, column (m) and ties to the  
17 MPSC Annual Report Form P-521, page 114, line 26.

18

19 **Q44. Why do you adjust Net Operating Income on Exhibit A-3, Schedule C1.1, lines**  
20 **3 through 20?**

21 A44. These adjustments reflect certain inclusions and exclusions to the reported Net  
22 Operating Income amount to arrive at an allowable rate case filing level. The  
23 inclusions for AFUDC, interest and dividend income, MERC operating income,  
24 customer interest, and amortization of loss on reacquired debt are allowable for  
25 ratemaking, but they fall below the calculation of NOI on the Income Statement.



Line  
No.

1           Conversely, the exclusions for certain corporate memberships and advertising,  
2           executive incentives, and regulatory assets and liabilities recovered under separate  
3           surcharges are not included for ratemaking, but they fall within the calculation of  
4           NOI on the Income Statement.

5

6   **Q45. What adjustment to Net Operating Income did you make on line 3 on Exhibit**  
7   **A-3, Schedule C1.1?**

8   A45. Line 3 reclassifies fuel handling from Fuel and Purchased Power to O&M.

9

10 **Q46. What are the adjustments on lines 4 through 20?**

11 A46. Line 4 adds interest and dividend income related to items included in working  
12 capital.

13

14           Exhibit A-3, Schedule C14, supports line 5, Excluded Corporate Memberships.  
15           This schedule calculates the removal of social and service organization membership  
16           expenses for the year ended December 2023. All membership dues for Chambers  
17           of Commerce are excluded from customer rates. The portion of other membership  
18           dues related to political activities is also removed. Some organizations disclose the  
19           portion of dues paid related to political activities on the invoice. For those amounts  
20           recorded to an account excluded for ratemaking, no adjustment was necessary. If  
21           the entire invoice was recorded to operating expense, I removed the portion related  
22           to political activity, as disclosed on the invoice. In addition, the Commission's  
23           Order in Case No. U-21534 directed the Company to demonstrate that the services  
24           and benefits of three specific Human Resources related memberships were not  
25           duplicative. To address this, I included one of the memberships (Center for Energy

Line  
No.

1 Workforce) in the historical elimination on line 3. The Company did not renew in  
2 2023 one of the remaining two specified in the Order (Human Capital Institute).  
3 Because there is only one remaining membership identified by the Commission in  
4 its Order (Institute for Corporate Productivity), the potential for any possible  
5 duplication of services and benefits among the three memberships has been  
6 eliminated. The total adjustment decreases O&M expense by \$0.2 million and  
7 increases NOI by \$0.2 million.

8  
9 Line 6, Excluded Advertising Expenses, is supported by Schedule C15, which  
10 classifies 2023 electric advertising expenses by categories as prescribed by the  
11 standard filing requirements. Advertising expenses included for ratemaking  
12 include public safety, conservation, and billing practices. This exhibit identifies  
13 the advertising expenses that have historically been accepted by the Commission  
14 and removes the remaining advertising expense. This adjustment results in a  
15 decrease in O&M expense of \$0.2 million and an increase in NOI of \$0.1 million.

16  
17 Line 7, MERC NOI Adjustment, is supported on Schedule C16. MERC's net  
18 income is effectively included in DTE Electric's NOI on Schedule C1.1, line 1.  
19 This occurs in two ways. First, MERC charges DTE Electric for fuel handling and  
20 that charge is included in DTE Electric's fuel expense (account 501) on Schedule  
21 C1.1, line 1, column (d), which is then part of the fuel handling reclassification to  
22 O&M expense on line 3, column (e). Second, MERC's profit or loss is included in  
23 the PSCR. Third Party Revenues (consisting of Third-Party Dock Services plus  
24 Net Coal & Transportation Sales) are credited, and Net Site Operating Expenses  
25 are expensed to customers in the PSCR mechanism (through a change in the

Line  
No.

1 delivered cost of coal). This inventory change is embedded in Fuel and Purchased  
2 Power expense shown on Exhibit A-3, Schedule C1.1, line 1, column (d). These  
3 two items are shown on Schedule C16, page 1 of 2. The fuel handling charge of  
4 \$9.7 million together with the PSCR inventory charge of \$8.0 million results in a  
5 net contribution to consolidated DTE Electric for ratemaking of \$17.7 million as  
6 shown on Schedule C16, column (b).

7  
8 I will now explain details of the adjustment on Schedule C1.1, line 7. First, a  
9 portion of the fuel handling charge recorded as O&M by DTE Electric is for  
10 MERC's depreciation, taxes, and interest. As detailed on Schedule C16, page 2 of  
11 2, column (c), I subtracted out the \$9.7 million fuel handling expense recorded by  
12 DTE Electric and replaced it with the same amount but in the detailed  
13 classifications shown in column (d). The total impact of the reclassification is  
14 shown on Schedule C16, page 2 of 2, column (e) and is carried forward to Schedule  
15 C1.1, line 7. The impact of this reclassification increases NOI by \$1.4 million,  
16 representing MERC's interest expense. This net addition to NOI is necessary to  
17 offset the expense reflected in DTE Electric's consolidated interest expense, which  
18 includes debt for MERC. This ensures there is no impact on customers in base  
19 rates.

20  
21 The Commission first authorized the above-described MERC accounting treatment  
22 in MPSC Case No. U-5041 (Accounting and Ratemaking for MERC), Order dated  
23 September 17, 1976, and reaffirmed its findings in MPSC Case No. U-5108  
24 (General Electric Rate Case) Order dated May 27, 1977, as well as in MPSC Case

Line  
No.

1 No. U-8578 (Detroit Edison's 1987 PSCR Plan Case), Order dated December 8,  
2 1987.

3

4 Line 8, PSCR Offsets, is supported by Schedule C17, and details three adjustments  
5 between revenue and fuel and purchased power. The first adjustment eliminates  
6 the amount of revenues that are collected via the PSCR factor to reset historical  
7 revenue to the PSCR base level. The second adjustment is to eliminate  
8 interconnection and ancillary transmission revenues that are netted against PSCR  
9 costs. Since these amounts are credited to customers in the PSCR reconciliation,  
10 they need to be eliminated from revenues in net operating income for base rates.  
11 The last adjustment is for steam revenue, which is included in net operating income,  
12 but the related fuel cost is not recovered in the PSCR. To make up for this shortfall,  
13 I reduced the revenue amount by the un-recovered cost. The sum of these three  
14 adjustments is a \$147.1 million reclassification between revenue and fuel on  
15 Exhibit A-3, Schedule C1.1, line 8.

16

17 Line 9 eliminates the revenues and expenses included in the nuclear surcharge.  
18 Schedule C18 details the components supporting the \$0.7 million net operating  
19 income adjustment.

20

21 Consistent with past practice, line 10 reduces incentive plan expense by \$10.4  
22 million to remove the incentive compensation for DTE Electric's top five executive  
23 officers. The adjustment is shown on Schedule C19.

Line  
No.

1 Line 11, MGM Rent, supported by Workpaper TMU-4, is for an expense included  
2 in O&M related to DTE Energy's use of a parking deck. I removed this expense to  
3 match the treatment of a related gain on the sale of land underlying the parking deck  
4 that is classified below the line. This adjustment results in a decrease in O&M  
5 expense of \$1.0 million and an increase in NOI of \$0.8 million.

6

7 Line 12, Customer Deposit Interest, is supported by Workpaper TMU-5 and  
8 reduces NOI by \$1.6 million recorded below the line as other interest in account  
9 431. It is included as an operating expense in the Company's revenue requirement  
10 since Customer Deposits are not included in the Company's capital structure.

11

12 Line 13 eliminates the revenues and expenses from the TRM related to former City  
13 of Detroit PLD customers because it is recovered via a separate surcharge and is  
14 not a part of base rates. Workpaper TMU-6 details the components supporting the  
15 \$1.1 million net income adjustment.

16

17 Line 14 eliminates the revenues and expenses from the EWR program because it is  
18 recovered via a separate surcharge outside of base rates. Workpaper TMU-7 details  
19 the components supporting the \$27.8 million NOI adjustment.

20

21 Line 15 eliminates the revenues and expenses from the REP because they are  
22 included in the regulatory liability that is separate from the Company's base rates.  
23 Workpaper TMU-8 details the components supporting the \$167.1 million NOI  
24 adjustment.

Line  
No.

1 Line 16 eliminates revenues and expenses related to the Low-Income Energy  
2 Assistance Fund (LIEAF). This is a separate surcharge program, which has no  
3 income impact. This adjustment as shown on Workpaper TMU-9 is necessary so  
4 that the normalized NOI detail is comparable to the forecast period.

5

6 Line 17 eliminates revenue from the Infrastructure Recovery Mechanism. This is  
7 a separate surcharge that started in December 2023 as authorized by the  
8 Commission's December 1, 2023 Order in Case No. U-21297.

9

10 Line 20 Energy Insurance Services (EIS) relates to the Company's investment for  
11 funding insurance. The Order in Case No. U-21297 requires the Company to  
12 include a forecast of the income from the insurance fund in projected operating  
13 income based on a five-year average in lieu of removing the EIS asset from working  
14 capital. The adjustment includes the five-year average of an EIS gain in NOI.

15

16 **Q47. Why are you making normalization adjustments to NOI as reflected on**  
17 **Exhibit A-3, Schedule C1.1, lines 23 through 39?**

18 A47. Consistent with current Commission policy, DTE Electric developed a projected  
19 test year ending December 31, 2026, based on projected changes from the year  
20 ended December 31, 2023 historical or actual test year. The year ended December  
21 31, 2023 historic test year was adjusted to reflect the same normal baseline as the  
22 twelve-months ending December 31, 2026 projected test year as far as rate levels,  
23 weather impacts and temporary or one-time revenue or expense impacts. All  
24 adjustments were made to the year ended December 31, 2023, reported NOI amount

Line  
No.

1 to arrive at a rate case filing level as the starting point to develop the twelve-months  
2 ending December 31, 2026, projected test year.

3

4 **Q48. What is the employee incentive plan normalization adjustment on line 24 of**  
5 **Exhibit A-3, Schedule C1.1?**

6 A48. Line 24, Employee Incentive Plan Adjustment, is supported by Schedule C20 and  
7 increases 2023 incentives expense by \$21.2 million. This is made up of three items.  
8 The first adjustment relates to the short-term incentive plan design (discussed in  
9 more detail by Witness Fix) which allows for a payout within a range of zero to  
10 200% of the target, depending on actual results achieved. Short-term incentive  
11 expense in 2023 was \$22.8 million below the 100% target. Of that amount, \$7.5  
12 million was accrued in the incentive tracker so the net adjustment to reflect  
13 incentives at 100% is \$15.3 million. The second item removes \$4.9 million of prior  
14 period adjustments related to short-term incentive. Since payments below the target  
15 and prior period adjustments may not recur, I have adjusted the historical amounts  
16 to a baseline level.

17

18 The last adjustment relates to long-term incentives. Long-term incentives in 2023  
19 include a \$1.1 million reduction for a decrease in expense for the 2020 through  
20 2023 performance shares based on performance relative to 100% of the target. (The  
21 Company applies the equity method to account for long-term Performance Shares;  
22 thus, any change in DTE Energy's share price between the grant date and payout  
23 date is generally reflected in DTE Energy's equity with no impact to expense.  
24 However, a portion of the incentive will be paid out in cash instead of DTE shares  
25 and the impact in payout changes for that portion is recognized in expense.) Since

Line  
No.

1 an incentives payout lower than the target may not recur, I have adjusted that  
2 amount in the historical expense. The three adjustments increase O&M by \$21.2  
3 million as shown on Schedule C20, column (d), line 5. The after-tax impact is  
4 \$15.7 million, shown on line 9.

5

6 **Q49. What is the basis for the \$106.0 million NOI Weather Normalization**  
7 **Adjustment you are supporting on Exhibit A-3, Schedule C1.1, line 25?**

8 A49. The rate case assumes that for electric sales, historical normal weather will occur  
9 for the forecast period. Thus, for comparison purposes the historical test year must  
10 be adjusted to a normal weather basis. Summer weather was colder than normal,  
11 and winter weather was warmer than normal in 2023, decreasing DTE Electric's  
12 pretax margin by \$143.1 million, and NOI by \$106.0 million, as shown on Schedule  
13 C21. Underlying the pretax margin decrease was sales revenue of \$183.3 million  
14 offset in part by a decrease in power supply cost of \$40.2 million. Company  
15 Witness Leuker discusses the weather impacts in more detail.

16

17 **Q50. What are the adjustments to O&M expense on lines 26 through 38?**

18 A50. Various O&M witnesses support the adjustments on line 26 through 31 and line 38.  
19 I support the adjustments on lines 32 through 36 as shown on my Exhibit A-13,  
20 Schedule C5.10, and line 37. Lines 32 and 33 normalize injuries and damages and  
21 environmental remediation expenses using averages due to the volatility in cost  
22 levels. Lines 34 through 37 normalize for temporary cost reductions in 2023.

23

24 **Q51. What are the adjustments on lines 42 through 45?**



Line  
No.

1 A51. Line 42 adds \$47.0 million of AFUDC income to offset the impacts of including  
2 construction work in progress (CWIP) in rate base. The federal, state, and local  
3 income tax expense related to AFUDC and interest income is already included in  
4 the income tax expense displayed on line 1, columns (i) and (j) of Exhibit A-3,  
5 Schedule C1.1.

6

7 Line 43 represents Amortization of the Loss on Reacquired Debt. To reduce interest  
8 costs, DTE Electric has redeemed and refinanced long-term debt securities in prior  
9 years in advance of their scheduled maturities. The cost related to each of these  
10 early redemptions is amortized over the life of the new issue as prescribed by the  
11 Commission's Uniform System of Accounts. The year ended December 2023  
12 amortization of the Loss on Reacquired Debt results in a decrease in net operating  
13 income of \$3.1 million. This expense is displayed on a pretax basis since the tax  
14 expense is already included in net operating income.

15

16 Line 44, Income Tax Effect of Interest, and line 45, Interest Synchronization, are  
17 supported and explained by Witness Vangilder on Exhibit A-3, Schedules C12 and  
18 C13, respectively.

19

20 **Q52. What is the Adjusted Normalized Year ended December 2023 NOI amount?**

21 A52. Inclusion of the rate case adjustments and normalization adjustments result in an  
22 Adjusted Normalized year ended December 2023 NOI of \$1,044.2 million. This  
23 amount is detailed in Exhibit A-3, Schedule C1.1, line 48 and is included in the  
24 historical revenue deficiency/ (sufficiency) calculation supported by Witness  
25 Vangilder.

Line  
No.

1     **Forecast Period**

2     **Q53. How was the financial forecast for the projected period, twelve months ending**  
3         **December 31, 2026, prepared?**

4     A53. Projected DTE Electric financial statements for the twelve months ending  
5         December 31, 2026 were based on projected changes from the adjusted normalized  
6         amounts for the year ended December 31, 2023. The projected period reflects an  
7         increase in revenue and higher net operating expenses. Revenue includes an  
8         increase in electric sales revenue and increased inter-company rent revenue. The  
9         revenue increases are offset by increased O&M, depreciation expense, income tax  
10        expense and property taxes. As previously discussed, regulatory assets recovered  
11        with surcharges are excluded from the forecast, so they will not impact base rate  
12        determination. I prepared the forecasted financial statements using inputs from  
13        numerous DTE Electric witnesses.

14

15     **Electric Income Statement Forecast**

16     **Q54. What information is included in the forecasted electric income statement**  
17         **contained within this filing?**

18     A54. The income statement shown on Exhibit A-13, Schedule C1, column (e), represents  
19         the projected DTE Electric NOI for the twelve-months ending December 31, 2026.  
20         DTE Electric's financial statements represent DTE Electric Company plus MERC.  
21         Exhibit A-13, Schedule C1.1 develops the twelve months ending December 31,  
22         2026, DTE Electric operating income statement based on projected changes from  
23         the year ended December 31, 2023 normalized amount.

Line  
No.

1   **Q55. How did you develop the revenues reflected in DTE Electric's operating**  
2       **income?**

3   A55. Line 1 of Exhibit A-13, Schedule C1, contains DTE Electric's revenues for the  
4       forecasted twelve-months ending December 31, 2026. Generally, these revenues  
5       were derived from the projected electric sales volumes provided by Witness Leuker  
6       multiplied by existing tariff rates, as calculated by Company Witnesses Willis,  
7       Turner and Hartley. These tariff rates include electric base tariff rates authorized  
8       in Case No. U-21534. Total revenues also include certain utility-related  
9       Miscellaneous Revenues that I support. As shown on Exhibit A-13, Schedule C3,  
10      page 2, I have excluded Nuclear, EWR, REP, IRM, and LIEAF surcharge revenues  
11      because they do not affect the revenue deficiency in base rates.

12

13   **Q56. What is the projected change in revenues from the historical normalized**  
14       **period to the projected period?**

15   A56. Exhibit A-13, Schedule C1, column (d) shows that the projected change in revenues  
16       is an increase of \$542.5 million. Schedule C3, page 1, of this exhibit compares the  
17       2023 normalized revenue amount to the twelve-months ending December 31, 2026  
18       revenue amount.

19

20   **Q57. Can you explain the revenue items on Exhibit A-13, Schedule C3?**

21   A57. Line 1 of Exhibit A-13, Schedule C3, page 1, represents electric sales distribution  
22       revenue. These projected revenues include a full year of the increase in tariff rates  
23       authorized in Case No. U-21297 effective in December 2023 and the increase from  
24       Case No. U-21534 effective in February 2025 and reflect higher overall service  
25       area sales in the projected period. Sales are discussed by Witness Leuker. Line 2

Line  
No.

1 is the revenue that recovers base fuel and purchased power. The change in this  
2 revenue component is the same amount as the change in base fuel and purchased  
3 power expense, discussed in more detail below. Company Witnesses Willis, Turner  
4 and Hartley support the twelve-months ending December 31, 2026, tariff revenue  
5 in their testimonies and exhibits.

6

7 Line 5 is Other Operating Revenues primarily consisting of: late payment charges,  
8 miscellaneous service charges, real estate rentals, and inter-company shared asset  
9 charges. The increase in the inter-company shared asset charge is due primarily to  
10 additional information technology assets that support both Electric and Gas  
11 operations. Line 7 reflects Rider 2 revenues related to special purpose facilities  
12 supported by Company Witness Cejas Goyanes.

13

14 Comparing the projected twelve months ending December 31, 2026 revenue of  
15 \$5,718.4 million to the 2023 normalized revenue of \$5,175.9 million, results in an  
16 increase in projected revenue of \$542.5 million as shown on page 1 of Exhibit A-  
17 13, Schedule C3, line 8.

18

19 **Q58. How was the Fuel and Purchased Power Expense portion of DTE Electric's**  
20 **operating expense developed?**

21 A58. Line 3 of Exhibit A-13, Schedule C1, contains DTE Electric's fuel and purchased  
22 power expense for the forecast period as supported by Witness Willis on Exhibit  
23 A-13, Schedule C4. The change in fuel and purchased power expense is due to an  
24 increase in sales volumes and an increased loss factor, offset by lower MISO  
25 purchase prices for customers on rates R10 and R3, and the elimination of non-

Line  
No.

1 capacity charges for customers on rate D13. As previously discussed, I adjusted  
2 the historical period to eliminate items captured in the PSCR as shown on Exhibit  
3 A-3, Schedule C17. Any actual under or over recoveries of fuel and purchased  
4 power will be reconciled in DTE Electric's annual PSCR filings.

5

6 **Q59. How was the O&M Expense portion of DTE Electric's operating expense**  
7 **developed?**

8 A59. To determine the projected test year O&M expenses for the instant case, DTE  
9 Electric started with actual year ended December 31, 2023 results normalized for  
10 unusual, non-recurring items and eliminations/reclassifications for ratemaking  
11 purposes. The normalized O&M amounts were then escalated for the effects of  
12 inflation and adjusted to reflect anticipated material changes. Line 4 of Exhibit A-  
13 13, Schedule C1, contains DTE Electric's O&M expenses for the forecast period.

14

15 In addition to me, Witnesses Guillaumin, Milo, Davis, Kryscynski, Hartley,  
16 Steudle, Leuker, Sparks, Foley, Fix and Cooper support the O&M expenses and  
17 describe them in their direct testimony. These witnesses also support the changes  
18 from the historic to the projected period within their respective areas. I support the  
19 inflation rates used in their projections. I support the Corporate Staff Group forecast  
20 and will explain the details later in my testimony. I also developed Injuries and  
21 Damages expense, and Environmental Remediation costs based on an historical  
22 average. I have summarized the development of the forecasted O&M expenses in  
23 Exhibit A-13, Schedule C5.

24

25 **Q60. How did you develop the inflation rates?**

Line  
No.

1 A60. As shown on Exhibit A-13, Schedule C5.15, I have calculated a composite inflation  
2 rate based on a labor factor and a non-labor factor. The inflation rate of 3.5% for  
3 2024 and 3% for 2025 and 2026 for internal labor is supported by Witness Fix. I  
4 assumed the same rate for contract labor since a portion of our contract workforce  
5 comes from the same unions as the DTE union employees. The inflation rate for  
6 non-labor costs is based on a consumer price index (CPI)-Urban published by  
7 S&P/IHS Markit. I used the labor and non-labor rates to calculate a composite rate  
8 of inflation for 2024, 2025, and 2026 as shown on line 15.

9

10 **Q61. Why are you using 3.5% and 3% inflation rates for labor rather than the CPI?**

11 A61. As discussed by Witness Fix, DTE Electric's labor costs are driven by either  
12 contracts that cover the Company's represented employees or market-based pay  
13 practices and thus are not directly tied to CPI. To forecast future labor costs, it is  
14 more appropriate to use a specific and known wage factor rather than an overall  
15 measure of inflation.

16

17 **Q62. What is the projected change in O&M Expense from the historical normalized**  
18 **amount to the projected period twelve months ending December 31, 2026?**

19 A62. Line 4 of Exhibit A-13, Schedule C1, column (d), shows the projected change in  
20 O&M increasing expense by \$219.6 million. The increase is due primarily to  
21 inflation, uncollectible accounts expense, Blue Water Energy Center operations,  
22 battery plant operations, generation plant maintenance, environmental compliance,  
23 tree trim expenses, distribution system maintenance including tree trimming, and  
24 marketing programs. These are partially offset by reductions related to savings from  
25 the Voluntary Separation Incentive Plan (VSIP), the conversion of the Belle River

Line  
No.

1 Power Plant to natural gas fuel, lower nuclear project (PERC) expense, lower  
2 nuclear outage accruals, savings from the Tree Trim surge program, reduced  
3 merchant fees, and lower customer service call volumes.

4

5 **Q63. Did you provide any input to the other DTE Electric witnesses' O&M**  
6 **projections?**

7 A63. Yes. I am proposing that the deferral of negative Other Post Employment Benefit  
8 cost (OPEB) and Pension expense, as supported by Witnesses Cooper and Fix,  
9 respectively, be continued in this case, and support the amortization of previously  
10 deferred OPEB balances. I am also sponsoring the amortization of the PERC  
11 regulatory asset reflected on Witness Davis's O&M exhibit, the amortization of  
12 deferred Advanced Distribution Management System (ADMS) program costs on  
13 Witness Kryscynski's O&M exhibit, the amortization of the Advanced Customer  
14 Pricing Pilot (ACPP) and Time of Day (TOD) regulatory assets on Witness  
15 Sparks's O&M Exhibit, and the amortization of deferred program costs for  
16 Charging Forward on Witness Foley's O&M exhibit.

17

18 **Q64. Can you explain the adjustment you made to Witness Cooper's forecast for**  
19 **OPEB costs?**

20 A64. Yes. Witness Cooper has forecasted retiree health care costs including DTE  
21 Electric's traditional OPEB plan. Since OPEB costs have been negative, a deferral  
22 to a regulatory liability was approved by the Commission in Case Nos. U-17767,  
23 U-18014, U-18255, U-20162, U-20561, U-20836, U-21297, and U-21534. I have  
24 reflected the continued deferral of the negative net OPEB expense on Witness  
25 Cooper's Exhibit A-13, Schedule C5.12.2, line 18, consistent with prior treatment.

Line  
No.

1 If net OPEB expense becomes positive in the future, then the expense will be  
2 charged against the regulatory liability. In addition, in Case No. U-21297, the  
3 Commission ordered that the Company must amortize the OPEB regulatory  
4 liability of \$128.4 million as of the historical test year (December 2022) over a  
5 seven-year period. I have reflected the amortization of the OPEB regulatory  
6 liability on Witness Cooper's Exhibit A-13, Schedule C5.12.2 line 19.

7

8 **Q65. Did you make an adjustment to Witness Fix's forecast for pension costs?**

9 A65. Yes. A pension expense deferral mechanism was approved by the Commission in  
10 Case Nos. U-20836, U-21297 and U-21534. I have reflected the deferral of the  
11 negative net pension expense on Witness Fix's Exhibit A-13, Schedule C5.12.1,  
12 line 18. If net pension expense becomes positive in the future, then the expense  
13 will be charged against the regulatory liability.

14

15 **Q66. How does the capitalization of Pension and OPEB costs impact Witness**  
16 **Cooper's and Fix's forecasted expense?**

17 A66. Exhibit A-13, Schedules C5.12.1 and C5.12.2, sponsored by Witnesses Fix and  
18 Cooper, respectively, detail the components of Pension and OPEB costs. Each  
19 schedule has a reconciliation of total cost to expense. A portion of the service cost  
20 component is capitalized to CWIP/Plant based on the related labor capitalized.  
21 Effective in 2018, the non-service cost components cannot be charged to capital  
22 under GAAP. Instead, the non-service costs that would have been capitalized under  
23 the traditional accounting treatment (but expensed under GAAP) are being recorded  
24 to a regulatory asset (or liability if cost is negative) instead of plant. The regulatory  
25 asset or liability is depreciated using the prior year's composite depreciation rate



Line  
No.

1 for plant in service, with the expense recorded to a unique account within  
2 Depreciation and Amortization expense. This treatment, approved in Case No. U-  
3 18255, results in recognizing the same expense and rate base that would have  
4 occurred under the historical accounting and ratemaking method.

5

6 **Q67. How does this impact Witness Cooper's and Witness Fix's exhibits?**

7 A67. The regulatory treatment is reflected on line 16 of Witness Fix's and Witness  
8 Cooper's Exhibit A-13, Schedules C5.12.1 and C5.12.2, respectively. The amount  
9 previously shown as capitalized to plant has been bifurcated into two lines. Line  
10 15 of C5.12.1 and C5.12.2 represents the capitalized service costs recorded to  
11 CWIP/Plant, and line 16 of C5.12.1 and C5.12.2 represents the capitalized non-  
12 service costs which are now recorded to a regulatory asset or liability.

13

14 **Q68. Can you explain the adjustment you made to Witness Davis's O&M forecast?**

15 A68. Yes. The Commission previously approved the deferral of certain nuclear project  
16 (PERC) costs above a base amount of \$15 million in Case No. U-20561. The base  
17 expense is shown on Witness Davis's Exhibit A-13, Schedule C5.3, line 21, along  
18 with \$1.6 million of PERC amortization on line 22, which represents a decrease of  
19 \$10.9 million from the historical period.

20

21 **Q69. How did you calculate the adjustment to PERC amortization expense on**  
22 **Witness Davis's O&M exhibit?**

23 A69. The calculation of the deferral and related amortization expense is shown on my  
24 Exhibit A-13, Schedule C5.17. Lines 2 through 4 show the difference between  
25 PERC actual and forecasted expenses and the \$15 million base amount. The PERC

Line  
No.

1 deferral amounts on line 4 are amortized over the subsequent five years. Lines 7  
2 through 16 show the annual expense for each vintage year and the total amortization  
3 that will occur in the projected period on line 17. The projected period amortization  
4 amount of \$1.6 million is carried to Witness Davis's Exhibit A-13, Schedule C5.3,  
5 line 22, column (o). The projection adjustment of \$10.9 million in column (m) is  
6 simply the difference between the forecasted amortization expense and the actual  
7 historical expense.

8

9 **Q70. Can you explain the adjustment you made to Witness Kryscynski's forecast?**

10 A70. Yes. In Case No. U-20162, the Commission approved the deferral of certain O&M  
11 costs related to the ADMS software project to a regulatory asset. The deferred costs  
12 include consulting and process reviews, process development, training, and  
13 software fees while the system is under development, with the amounts shown on  
14 capital Exhibit A-12, Schedule B5.4, page 1, line 25, sponsored by Witness  
15 Rademacher. The regulatory asset will be amortized over a fifteen-year period  
16 beginning with the year after the system's in-service date. The final components of  
17 the ADMS software project were placed in service in February 2023. As shown on  
18 Witness Kryscynski's O&M Exhibit A-13, Schedule C5.6, line 12, column (l), the  
19 amortization expense is expected to be \$1.2 million in the projected test period.  
20 The calculation of the amortization expense is shown on my Exhibit A-13, Schedule  
21 C5.6.2.

22 **Q71. Can you explain the adjustments you made to Witness Foley's forecast?**

23 A71. Yes. In Case No. U-20162, the Commission approved the Company's original  
24 Charging Forward program intended to develop infrastructure related to electric

Line  
No.

1 powered vehicles and the costs for the program are to be deferred to a regulatory  
2 asset. In Case Nos. U-20935, U-20836, U-21297 and U-21534 the Commission  
3 approved additional components to the Charging Forward program, now called the  
4 Transportation Electrification Plan (TEP). Per the Order in Case No. U-20561,  
5 reviewed costs will be amortized over five years, beginning with their inclusion in  
6 base rates. Witness Foley supports the costs for the program shown on his Exhibit  
7 A-12, Schedule B5.9. I show the calculation of the amortization expense on my  
8 Exhibit A-13, Schedule C5.9.1. Line 2 of my Exhibit shows the regulatory asset  
9 expenses supported by Witness Foley. Lines 5 through 12 calculate the  
10 amortization by vintage year for the test period of \$5.7 million. This amount is  
11 carried to Witness Foley's O&M Exhibit A-13, Schedule C5.9, line 11, column (I).

12

13 **Q72. Can you explain the adjustments you made to Witness Sparks's forecast?**

14 A72. In Case No. U-20162, the Commission approved the Company's Advanced  
15 Customer Pricing Pilot (ACPP) and authorized the deferral of up to \$7.3 million of  
16 one-time implementation costs. Additionally, in Case No. U-20836, the  
17 Commission approved a request for regulatory asset treatment for certain  
18 implementation costs associated with the Company's Time of Day (TOD) rate  
19 offering effective November 2022. The costs for these projects are supported by  
20 Witnesses Sparks and Foley on Exhibit A-13, Schedule C5.9.2. The deferred costs  
21 are being amortized over five years. I show the calculation of \$1.3 million of ACPP  
22 amortization expense for vintage years 2019 through 2022 on my Exhibit A-13,  
23 Schedule C5.9.3, line 6. I show the calculation of \$1.7 million of TOD amortization  
24 expense for vintage years 2022 through 2023 on line 7. The sum of the ACPP and

Line  
No.

1 TOD amortization costs of \$3.0 million is carried to Witness Sparks's O&M  
2 Exhibit A-13, Schedule C5.7, line 8, column (n).

3

4 **Q73. How was the Depreciation and Amortization Expense portion of DTE**  
5 **Electric's operating expense developed?**

6 A73. Line 5 of Exhibit A-13, Schedule C1, contains DTE Electric's depreciation and  
7 amortization (D&A) expenses for the forecasted period. D&A includes book  
8 depreciation, which is based on existing plant balances, plus new capital  
9 expenditures and assumed retirements, using a half year convention. Depreciation  
10 expense is calculated using the rates authorized by the Commission in Case No. U-  
11 18150.

12

13 **Q74. What is the projected change in D&A Expense from the historical normalized**  
14 **amount to the projected period?**

15 A74. Exhibit A-13, Schedule C1, column (d) shows the projected change in D&A,  
16 increasing expense by \$211.8 million. Schedule C6 of this exhibit shows the  
17 development of the projected period ending December 31, 2026, D&A expense of  
18 \$1,359.9 million from the 2023 normalized D&A expense of \$1,148.1 million. The  
19 \$54.1 million increase in depreciation and amortization of plant and software on  
20 line 4 includes an increase of \$250.7 million for capital in-service movement across  
21 all tangible plant categories, with the largest drivers being distribution and general  
22 plant. The increases are offset by \$65.6 million from retirements across all tangible  
23 plant categories, including \$571.0 million of coal assets at Belle River.  
24 Additionally, software amortization decreases by \$31.9 million in the projected  
25 period. The increase on line 4 is also offset by \$99.1 million due to reclassifying

Line  
No.

1 \$3.5 billion of Monroe generation *gross* plant to a regulatory asset effective January  
2 31, 2025. The net plant being transferred is \$2.1 billion.

3

4 **Q75. Why are you reclassifying \$2.1 billion of Monroe generation net plant to a**  
5 **regulatory asset?**

6 A75. The Commission approved a settlement agreement in the Company's Integrated  
7 Resource Plan (IRP) in Case No. U-21193 by its Order dated July 26, 2023. Among  
8 other things, the Order requires the Company to securitize \$1.045 billion related to  
9 the Monroe Power Plant and the Belle River coal assets. The Belle River coal assets  
10 of approximately \$233 million (net) are assumed to be securitized in December  
11 2026, leaving \$812 million to be securitized after the retirement of the Monroe  
12 Power Plant, expected in 2032. The portion of the plant to be securitized will remain  
13 classified within plant in service until it is retired. The balance of the plant not being  
14 securitized is to be recovered as a regulatory asset over fifteen years. Therefore,  
15 approximately \$2.1 billion of net plant will be reclassified from plant in service to  
16 a regulatory asset effective January 31, 2025.

17

18 **Q76. Can you explain the \$157.3 million related to the Monroe regulatory asset on**  
19 **line 8 of Exhibit A-13, Schedule C6?**

20 A76. Yes. As shown on Exhibit A-13, Schedule C6, line 8, the amortization of the  
21 Monroe regulatory asset over a 15-year period is forecasted at \$157.3 million. The  
22 amortization is separately calculated and supported on my Exhibit A-12, Schedule  
23 B4.4. It includes \$140.1 million of amortization on the \$2.1 billion balance  
24 transfer. This is partially offset by the \$99.1 million reduction in plant depreciation  
25 on line 4 of Exhibit A-13, Schedule C6 for a net impact of \$41.1 million from the

Line  
No.

1 reclassification. Amortization expense also includes approximately \$17.2 million  
2 related to the projected plant expenditures shown on line 5. I will explain the  
3 derivation of the regulatory asset in the balance sheet forecast portion of my  
4 testimony.

5

6 **Q77. What is the amortization of Demand Response (DR) on line 9 of Exhibit A-13,**  
7 **Schedule C6?**

8 A77. The Commission had previously approved regulatory assets for under recovered  
9 DR costs for the years 2019 and 2020. The 2021 DR regulatory asset was approved  
10 in 2023. The historical period reflects the recognition of the 2021 regulatory asset  
11 (credit to expense), partially offset by the amortization of the previously recognized  
12 2019 and 2020 DR regulatory assets over three years.

13

14 In 2024, the Commission approved a \$3.2 million regulatory asset for the 2022 DR  
15 program. In 2025, it approved a \$1.8 million regulatory liability for the 2023 DR  
16 program. I am requesting amortization related to the 2022 regulatory asset and  
17 2023 regulatory liability in the instant case.

18

19 **Q78. What is the amortization of Capitalized Pension and OPEB on lines 10 and 11**  
20 **of Exhibit A-13, Schedule C6?**

21 A78. As I previously discussed regarding Witness Fix's and Cooper's exhibits, the non-  
22 service cost components of pension and OPEB costs are being charged to a  
23 regulatory asset or liability instead of to plant. These items are expensed using the  
24 composite depreciation rate for plant in service.

Line  
No.

1   **Q79. What plant retirements have been forecasted?**

2   A79. Steam plant retirements are forecasted at \$626.2 million from January 2024 to  
3       December 2026, including \$571.0 million for the Belle River coal assets. The  
4       retirement of \$157.0 million for Belle River unit 1 coal assets is expected in 2025  
5       and \$414.0 million related to unit 2 and jointly used coal assets is expected in 2026.  
6       Approximately \$566.3 million of scheduled retirements of computer equipment and  
7       amortizable plant are reflected. I am also estimating approximately \$167.2 million  
8       in annual routine retirements based on recent history of other depreciable plant.

9

10   **Q80. How does DTE Electric account for the plant retirements?**

11   A80. The original cost is credited out of plant in service and debited to accumulated  
12       depreciation. This treatment is prescribed by the Uniform System of Accounts  
13       Electric Plant Instruction number 10 (F) which states, "The book cost less net  
14       salvage of depreciable electric plant retired shall be charged in its entirety to  
15       Account 108, Accumulated provision for depreciation and amortization."

16

17   **Q81. What is the projected change in Property Tax Expense?**

18   A81. Line 6 of Exhibit A-13, Schedule C1, column (d) shows that the total projected  
19       change in property tax expense is an increase of \$80.2 million due primarily to  
20       increases in plant balances. Witness Wisniewski explains the changes and supports  
21       the amount on Exhibit A-13, Schedule C7.1.

22

23   **Q82. What is the projected change in Other Tax Expense?**

24   A82. Line 7, column (d) of Exhibit A13, Schedule C1 (supported by Witness  
25       Wisniewski) shows that the total projected change in other tax expense is an

Line  
No.

1 increase of \$5.5 million. I directed her to add an increase in payroll taxes of \$2.0  
2 million related to increases in O&M labor.

3

4 **Q83. What is the projected change in State and Local Income Tax expense?**

5 A83. Line 8 of Exhibit A-13, Schedule C1, column (d) reflects an \$11.4 million decrease  
6 in state and local tax expense, including Michigan Corporate Income Tax (MCIT)  
7 and municipal income taxes. Witness Wisniewski explains the changes and  
8 supports the amount on Exhibit A-13, Schedules C9 and C10.

9

10 **Q84. What is the projected change in Federal Income Tax Expense from the historic**  
11 **normalized amount to projected period?**

12 A84. The change in federal income tax decreases expense by \$5.0 million as shown on  
13 Line 9 of Exhibit A-13, Schedule C1, column (d). Witness Wisniewski explains  
14 the changes and supports the amount on Exhibit A-13, Schedule C8.

15

16 **Q85. How did you compute Operating Income?**

17 A85. Operating Revenues minus Operating Expenses yields Operating Income shown on  
18 line 12 of Exhibit A-13, Schedule C1. Operating Income is projected to increase  
19 due to higher revenues from a full year of new base rates in Case No. U-21297,  
20 effective December 2023 and new base rates from Case No. U-21534 effective  
21 February 2025. The increase in revenues is partially offset by increased O&M,  
22 depreciation and property taxes related to capital additions.

23

24 **Q86. What information is contained on the income statement line items below**  
25 **Operating Income?**



Line  
No.

1 A86. Lines 14 and 15 on Exhibit A-13, Schedule C1, represent items that are includable  
2 for ratemaking, but fall below the calculation of NOI on the income statement. Line  
3 14 reflects AFUDC related to capital expenditures carried from Exhibit A-13,  
4 Schedule C11. It has two components. The first is an AFUDC offset equal to the  
5 amount of AFUDC included in CWIP (line 6 of Schedule C11). The second  
6 component removes the return on the AFUDC embedded in CWIP (line 8 of  
7 Schedule C11). This additional credit results in a revenue requirement of zero for  
8 the AFUDC eligible projects within CWIP and is calculated on Exhibit A-13,  
9 Schedule C11.1.

10

11 Consistent with past practice, the loss on reacquired debt results from the early  
12 redemption of securities, which are refinanced with lower cost issues. Line 15 of  
13 Schedule C1 is the annual amortization of losses on debt reacquired in prior periods.  
14 The forecast does not reflect additional early redemptions. Finally, line 17 of  
15 Schedule C1 provides Adjusted Net Operating Income. Adjusted NOI is projected  
16 to increase from the historical test period due to the factors that impact Operating  
17 Income and higher AFUDC.

18

19 **Q87. How does AFUDC impact the Company's revenue requirement and**  
20 **deficiency?**

21 A87. AFUDC represents the financing costs incurred while projects are under  
22 construction. Such costs are added to the asset being constructed with a  
23 corresponding credit to the income statement. AFUDC is generally applied to  
24 projects greater than \$50,000 and lasting more than six months. The accrual of  
25 AFUDC ceases once the asset is complete and placed in service. Including the

Line  
No.

1 credit to income from AFUDC offsets the impact of including CWIP in rate base  
2 and therefore, projects that do not go into service during the projected test period  
3 have no impact on the Company's revenue requirement and deficiency.

4

5 **Q88. What impact should a disallowance of projects that do not go into service**  
6 **during the projected test period, on which AFUDC is accrued, have on the**  
7 **Company's requested rate relief?**

8 A88. Such disallowances should not have any impact. To ensure that is the result, either  
9 the proposed disallowances for projects not going into service should be excluded  
10 from any reductions to rate base approved by the Commission, or a corresponding  
11 adjustment (reduction) in pre-tax AFUDC should be added to offset the removal of  
12 the projects from approved rate base.

13

14 **Q89. What is the projected period NOI amount shown in Exhibit A-13, Schedule**  
15 **C1?**

16 A89. Line 17 displays the Company's projection of the twelve months ending December  
17 31, 2026, NOI of \$1,107.9 million.

18

19 **Corporate Staff Group (CSG) Costs**

20 **Q90. What is the CSG?**

21 A90. The CSG is a shared services organization, "DTE Energy Corporate Services LLC"  
22 (LLC), which includes corporate staff functions. This business model provides  
23 efficiency, cost savings and enhanced governance and internal controls. Each  
24 organization within the CSG provides enterprise-wide services.

Line  
No.

1   **Q91.   What organizations are included in the CSG?**

2   A91.   The organizations within the CSG provide a variety of Administrative and General  
3       (A&G) type services to the Company. These include:

- 4           •   Audit Services
- 5           •   Accounting and Planning
- 6           •   Tax
- 7           •   Finance and Treasury
- 8           •   Corporate and Governmental Affairs
- 9           •   Communications
- 10          •   Corporate Offices
- 11          •   Supply Chain
- 12          •   Corporate Fleet and Facilities
- 13          •   Human Resources
- 14          •   Information Technology
- 15          •   Legal
- 16          •   Regulatory Affairs
- 17          •   Environmental Management and Safety
- 18          •   Project Management Organization (PMO)

19

20   **Q92.   Does the LLC provide other services in addition to Corporate Services?**

21   A92.   Yes. Customer Service also resides at the LLC and operates under a shared service  
22       model, but their span of support is only to the regulated DTE Electric and DTE Gas  
23       distribution operations versus the enterprise-wide orientation of the CSG.  
24       Customer Service O&M expenses are sponsored by Witness Sparks.

Line  
No.

1   **Q93. What type of O&M expenses do you support for the CSG organizations?**

2   A93. I support the CSG expense projections included in the A&G accounts on Exhibit  
3       A-13, Schedule C5.10.

4

5   **Q94. What expenses are included in account 920 on line 3?**

6   A94. Account 920 reflects internal labor costs that are allocated to DTE Electric for the  
7       CSG organization.

8

9   **Q95. What type of expenses are included in account 921 on line 5?**

10   A95. The largest cost items in line 5, Office Supplies and Expenses, are for software  
11       maintenance and telecommunications. Witness Ambrose provides more detail on  
12       the O&M expenses for the IT organization. This account also includes bank fees,  
13       assessments, and utilities expenses.

14

15   **Q96. What is the negative expense in account 922 on line 6?**

16   A96. Line 5 reflects the transfer of A&G costs to capital as an overhead. The amount of  
17       A&G transferred is based on the percentage of total direct labor charged to capital.

18

19   **Q97. What is included in account 923 on line 7?**

20   A97. The account for Outside Services primarily includes contract labor for IT. It also  
21       includes security services, janitorial services, external audit fees and consulting  
22       services.

23

24   **Q98. What expenses are included in lines 8 through 19?**

Line  
No.

1 A98. These lines are for property insurance, injuries and damages, advertising,  
2 environmental remediation, rents, maintenance of general plant, and other  
3 miscellaneous expenses.

4  
5 **Q99. Can you explain the rate case adjustments and normalizations reflected in**  
6 **columns (d) and (e), respectively on Exhibit A-13, Schedule C5.10?**

7 A99. Column (d) shows rate case adjustments, including \$3.8 million for the elimination  
8 of costs recovered via the REP and certain excluded costs (advertising, corporate  
9 memberships, advocacy expense and MGM rent expense). In addition, line 3  
10 includes a reduction of \$10.4 million to remove the incentive compensation for  
11 DTE Electric's top five executive officers. Column (e) on line 21 is an O&M  
12 increase of \$51.4 million that includes the normalization of \$15.9 million for  
13 temporary cost reductions in 2023, increases for injuries and damages and  
14 environmental remediation, and an increase in incentive expense as previously  
15 discussed.

16  
17 **Q100. What makes up the \$15.9 million of temporary cost reductions in 2023?**

18 A100. The details are listed in footnote 2 of Exhibit A-13, Schedule C5.10, page 1 and  
19 include \$3.5 million of deferred base pay increases for non-union employees, \$2.3  
20 million for a temporary reduction in janitorial and building services, and \$10.0  
21 million of temporary reductions in Information Technology expense (refer to  
22 Witness Ambrose for additional details on IT normalization adjustments). These  
23 temporary reductions were taken to mitigate the financial challenges experienced  
24 by the Company in 2023 as further discussed by Witness Bruzzano and are not  
25 planned to recur in the projected test period.

Line  
No.

1    **Q101. What adjustment did you make to Injuries and Damages?**

2    A101. Consistent with the method approved in Case No. U-21534 and prior cases, I used  
3       a historical average to determine the projected test year amount for injuries and  
4       damages to smooth out any year over year variance. The calculation is shown on  
5       page 3 of Exhibit A-13, Schedule C5.10.

6

7    **Q102. What adjustment did you make to Environmental Remediation?**

8    A102. I used a five-year historical average to determine the projected test year amount for  
9       environmental remediation costs consistent with the method applied in Case No.  
10       U-21534 and U-21297. The calculation is shown on page 3 of Exhibit A-13,  
11       Schedule C5.10.

12

13   **Q103. What projected adjustments did you make to O&M as reflected in columns (g)**  
14       **through (j)?**

15   A103. Increases based on the inflation rate were applied to the adjusted historical test  
16       period expenses for the period January 2024 through December 2026. Labor was  
17       reduced by \$9.6 million on line 3, column (j), for savings from the Voluntary  
18       Separation Incentive Plan (VSIP) supported by Witness Leslie. Line 3 also includes  
19       an increase of \$1.0 million for new employees needed to support compliance work  
20       for a financing program from the Department of Energy (Federal Funds  
21       Compliance Management). Witness Lepczyk explains the financing program and  
22       related expenses.

23

24       Line 4, Amortization of Incentive Tracker, reflects a credit of \$459,000 and is  
25       supported on Exhibit A-13, Schedule C5.10.1. As I will explain in more detail in

Line  
No.

1 the balance sheet section of my testimony, the Commission approved a recovery  
2 mechanism for incentive compensation related to operating metrics that provided  
3 for deferral treatment above or below the base amount to be recovered or refunded.  
4 This schedule calculates the amortization expense related to the 2022, 2023 and  
5 2024 layers. The layers for 2022 and 2023 on lines 4 and 5 of Schedule C5.10.1,  
6 respectively, reflect the regulatory deferrals approved in Case No. U-21534. Line  
7 6 increases the 2023 regulatory liability for an adjustment recorded that was not  
8 reflected in Case No. U-21534. Line 7 reflects the amount accrued for 2024. The  
9 net of the regulatory assets and liabilities results in an annual credit to expense in  
10 the projected period of \$459,000 as shown on line 8.

11

12 Line 5 of Exhibit A-13, Schedule C5.10, Office Supplies, reflects an increase of  
13 \$9.7 million for software license fees. The structure of new service contracts  
14 requires the annual cost to be expensed as incurred per the Company's accounting  
15 policy. Previous contracts were capitalized and amortized as intangible plant over  
16 the contract period. This increase in O&M is offset by a decrease in amortization  
17 expense within DD&A.

18

19 Line 7, Outside Services, reflects an increase of \$5.7 million for higher expenses  
20 related to IT projects in the projected test period. Witness Ambrose supports the  
21 changes in IT O&M.

22

23 Line 16, Rents, reflects a reduction of \$152,000. The Company previously held a  
24 lease for the occasional use of a corporate jet. The lease ended in 2023 and was not  
25 renewed.

Line  
No.

1   **Q104. With these adjustments, what is the projected test period amount for**  
2       **Administrative and General O&M expense?**

3   A104. Based on the adjustments described above, A&G expense is \$224.1 million for the  
4       projected test period ending December 31, 2026.

5  
6   **Q105. How are the CSG cost allocations to DTE Energy companies accomplished?**

7   A105. CSG costs are first incurred and accumulated at the LLC. Each department within  
8       a corporate staff organization identifies products and services it expects to provide  
9       to legal entities and/or business units based on the corporate staff organization's  
10      scope of work. These products and services are then analyzed to determine the  
11      most appropriate measure, which represents a unit of work, to be used in  
12      determining the billing of products or services being provided to DTE Electric and  
13      other DTE entities, by the administrative function. This measurement mechanism  
14      is called a cost driver. The cost driver, in cost accounting terms, is the unit of  
15      work/output that is used to determine a formula for billing the products or services  
16      to DTE Electric and other DTE entities. As departments incur expenses during the  
17      year, they are accumulated in cost pools. The pools are distributed and billed to  
18      DTE Electric and other DTE entities pursuant to the appropriate cost driver.

19  
20   **Q106. How does this cost driver allocation process work?**

21   A106. Cost drivers represent units of work that best reflect the content of the work  
22      performed. For example, the Company's payroll department within Corporate  
23      Services processes paychecks. Given the transactional nature of this work, the  
24      volumetric cost driver of "paychecks processed" provides the best indication of  
25      work performed by this group for a specific legal entity. This department provides



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No.

1 services for DTE Electric and other DTE entities and thus, payroll processing costs  
2 are billed based on the volume of paychecks processed for DTE Electric during the  
3 year. Other examples within the CSG include invoices paid, number of system  
4 application users, and application support hours. Cost drivers are evaluated and  
5 established based on resource consumption. These cost driver standards and levels  
6 of support are periodically reviewed and updated to reflect actual experience.

7

8 **Q107. Has this cost driver allocation methodology been reviewed by the Commission**  
9 **in prior rate cases?**

10 A107. Yes. This is the same cost allocation methodology supported by DTE Electric and  
11 approved by the Commission in DTE Electric's general rate cases going back to  
12 Case No. U-13808, and DTE Gas's general rate cases going back to Case No. U-  
13 13898.

14

15 **Q108. How has the Company billed costs for which no direct cost driver was**  
16 **discernable?**

17 A108. While most costs have been billed to DTE Electric and its affiliated companies  
18 based on the direct cost drivers I have described, a limited number of administrative  
19 activities are shared across the enterprise that do not possess cost driver attributes  
20 (a unit of work directly attributed to a legal entity), or that are incurred on behalf of  
21 the parent, DTE Energy, that indirectly benefit DTE Electric. It is in these cases  
22 that the Company uses the commonly accepted cost allocation methodology  
23 traditionally referred to as the Massachusetts Formula (Mass Formula). The Mass  
24 Formula, which utilizes a three-factor formula of gross margin, net plant, and labor  
25 costs, is designed to measure relative size and complexity as a means of assessing

Line  
No.

1 the degree of support services attributable to each individual company, within the  
2 context of the broader enterprise.

3

4 **Q109. Has the Commission approved the use of the Mass Formula in allocating**  
5 **common costs in prior cases?**

6 A109. Yes. Consistent with the cost driver methodology, the use of the Mass Formula for  
7 the allocation of CSG common costs was approved by the Commission in DTE  
8 Electric's prior general rate cases as well as in DTE Gas's general rate cases.  
9 Examples of CSG costs that utilize the Mass Formula include certain Corporate  
10 Communication, Governmental Affairs, Investor Relations, Corporate Secretary  
11 activities, and DTE Energy Board of Director fees.

12

13 **Information Technology O&M**

14 **Q110. What is included in Information Technology O&M?**

15 A110. IT costs are included in A&G expense on Exhibit A-13, Schedule C5.10. IT O&M  
16 consists of expenses related to project work along with on-going and base operating  
17 expense not tied to specific projects. Non-project costs include software  
18 maintenance, software licenses, cloud computing fees, software as a service,  
19 hardware and software defect remediation, business support services, and IT  
20 administration. Witness Ambrose provides additional information and an exhibit  
21 supporting IT O&M expenses.

22

23 **Q111. How are Information Technology expenses differentiated from capital**  
24 **expenditures?**

Line  
No.

1 A111. DTE Electric follows the FERC Uniform System of Accounts (USoA), per Title 18  
2 of the Code of Federal Regulations, for its capitalization policies, in accordance  
3 with the MPSC Order in Case No. U-14811. Costs which do not meet the criteria  
4 for capitalization are charged to expense. Items that are expensed include work  
5 during the preliminary project stage (resource allocation, performance  
6 requirements, vendor identification), and work during the post implementation  
7 stage (training and application maintenance); and upgrades and enhancements  
8 which do not result in significant, additional functionality (bug fixes, table changes,  
9 screen changes, routine logic changes). The IT capital projects supported by  
10 Witnesses Ambrose reflect only the cost of the components eligible for  
11 capitalization under the Company's policy.

12

13 **Corporate Staff Capital Expenditures**

14 **Q112. What is the nature of the capital expenditures incurred by CSG functions?**

15 A112. These expenditures reflect the annual capital requirement investment levels  
16 required for CSG organizations to deliver services to DTE affiliates. The largest  
17 categories of capital expenditures relate to information technology, physical  
18 infrastructure, and fleet.

19

20 **Q113. Why are these costs charged directly to DTE Electric?**

21 A113. CSG capital costs are generally incurred on behalf of all DTE affiliates. (Any  
22 projects or costs specific to other entities are charged directly to that company.)  
23 Thus, DTE Electric records 100% of the shared asset capital expenditures for CSG  
24 organizations and then charges a capital usage fee (Shared Asset Charge) to DTE  
25 affiliates for each affiliate's proportionate use of these assets which are owned by

Line  
No.

1 DTE Electric and jointly used by the companies. For example, DTE Gas occupies  
2 space in buildings owned by DTE Electric (e.g., the headquarters complex).  
3 Additionally, the Corporate Services Group and Customer Service organization  
4 providing services to DTE Gas or other affiliates do not own any of the assets or  
5 infrastructure required to function; the assets are owned by DTE Electric. The  
6 charge is comprised of the return on the assets and the related depreciation incurred  
7 by DTE Electric. The capital usage fee (Shared Asset Charge) is included in other  
8 operating revenue.

9

10 **Q114. How does the Shared Asset structure benefit utility customers?**

11 A114. This structure minimizes duplication of costs that would otherwise be required at  
12 the individual utilities. By using the same building for multiple groups, space usage  
13 can be optimized by filling up the available offices with employees from a different  
14 company or department. This helps avoid having to own or rent additional  
15 buildings for DTE Gas or the LLC. The same idea applies to computer  
16 infrastructure and office equipment. Sharing infrastructure not only reduces  
17 investment costs, but it also reduces operating and maintenance expenses (e.g.,  
18 lighting, heating and cooling, water, janitorial services, repairs, computer  
19 equipment maintenance, security). Thus, overhead costs for DTE and the  
20 individual utilities are reduced.

21

22 **Q115. How is the Shared Asset cost allocated from DTE Electric to affiliates?**

23 A115. The CSG capital costs incurred by DTE Electric must be paid for by the companies  
24 that utilize those assets, based on each company's proportionate share, to ensure  
25 DTE Electric customers are not subsidizing costs for DTE Gas and other DTE

Line  
No.

1 affiliates. The shared asset charge from DTE Electric to each affiliate is based on  
2 cost drivers for each group of assets. Buildings and furniture are allocated based on  
3 the location of employees and the cost drivers associated with the functions  
4 performed by those employees. Similarly, computer systems are allocated based on  
5 user headcount and their related cost drivers. For example, Customer Service  
6 building and computer costs are allocated between DTE Electric and DTE Gas  
7 based on their respective number of utility customers.

8

9 **Q116. How are expenditures underlying the shared asset charge reviewed for**  
10 **reasonableness and prudence?**

11 A116. As outlined above, the capital investments are owned by DTE Electric; therefore,  
12 the total capital investment, including return on capital and the related depreciation;  
13 along with the reasonableness and prudence of the project, is reviewed in DTE  
14 Electric rate cases. The review of the shared asset investments in an Electric rate  
15 case also encompasses the shared asset charge (expense) to affiliates, including  
16 DTE Gas. Upon approval of the investment in a DTE Electric rate case, the DTE  
17 Electric revenue requirement is reduced by the amount it receives from affiliates  
18 (Shared Asset charge), including DTE Gas, for use of the assets.

19

20 **Q117. If a shared asset investment and the associated revenue credits are approved**  
21 **in a DTE Electric rate case, what should be the outcome with respect to the**  
22 **corresponding expense in a DTE Gas rate case?**

23 A117. The corresponding expense should also be approved in a DTE Gas rate case as  
24 reasonable and prudent. As discussed above, the total cost of the assets and the  
25 shared asset charge (representing the proportionate use of the asset) to affiliates,

Line  
No.

1 including DTE Gas, are reviewed for reasonableness and prudence by the  
2 Commission in DTE Electric general rate cases. Shared asset capital projects  
3 undergo the same review process in Electric rate cases as all other capital projects.  
4 Once a project has been approved as reasonable and prudent in a rate case, it should  
5 not be relitigated in subsequent rate cases. A review of shared asset costs and related  
6 revenue credits previously approved in a DTE Electric rate case within a DTE Gas  
7 rate case would be redundant, an inefficient use of Company and Commission  
8 resources, and potentially result in contradictory determinations.

9

10 **Q118. What are the required adjustments for Shared Asset investments that are**  
11 **disallowed by the Commission in this rate case?**

12 A118. If the Commission disallows capital related to a shared asset project, DTE Electric  
13 must also reduce its projected revenue credit related to its affiliates' proportionate  
14 share of those disallowed costs.

15

16 **Q119. What level of capital expenditures do you expect the CSG organizations to**  
17 **incur?**

18 A119. Company Witness Ambrose supports \$536.5 million for IT projects in the bridge  
19 and projected periods on his Exhibit A-12, Schedule B5.7. I support Exhibit A-12,  
20 Schedule B5.8, which provides the capital projections for physical infrastructure,  
21 fleet, and other projects, totaling \$321.2 million for 2024 through 2026.

22

23 **Q120. What capital expenditures are included on Exhibit A-12, Schedule B5.8, page**  
24 **1, line 1, Vehicle Fleet?**

Line  
No.

1 A120. Line 1, Fleet, represents the cost of new vehicles and power operated equipment.  
2 Items such as cars, trucks, bucket trucks, trailers, and forklifts are replaced to  
3 provide safe and reliable equipment as the fleet ages. The Company uses a  
4 proprietary model which develops a comprehensive asset life cycle that optimizes  
5 total cost of ownership. Historic ownership costs and operational data are used to  
6 develop a replacement strategy specific to DTE Electric. Assets with the greatest  
7 reduction to maintenance and ownership costs are chosen for replacement. The  
8 decrease in 2025 reflects a retiming of a portion of expenditures to 2026. The  
9 increase in 2026 reflects the cost for bucket trucks and digger derricks that have not  
10 been available for purchase in prior years due to supply shortages.

11

12 **Q121. What is Facilities Construction and Upgrade on line 2?**

13 A121. Line 2, Facilities Construction & Upgrade, includes capital maintenance and  
14 replacement items such as roofs, facades, electrical, plumbing, heating and cooling  
15 equipment, office space updates, elevators, and cranes. Capital maintenance  
16 standards are applied to optimize life cycle costs and maintain safety. The capital  
17 projects for the historical, bridge and test periods are detailed in Exhibit A-12,  
18 Schedule B5.8, page 2. The expenditures in 2024 were largely approved in Case  
19 No. U-21534, except for approximately \$15.0 million. This includes \$1.7 million  
20 for supply and return fan replacement at the headquarters building (line 7), \$1.6  
21 million for elevators at Monroe Power Plant (line 15), \$0.9 million additional costs  
22 for a roof replacement at the Warren Service Center (line 16), \$6.3 million for  
23 higher than expected costs to update office spaces, including audio/visual  
24 equipment (lines 17 through 20), and \$4.1 million for renovations to the General  
25 Offices building (line 14). The \$4.1 million allocated for renovations at the General

Line  
No.

1 Office building in 2024 was to bring the office space up to code, including all safety  
2 functions, HVAC, plumbing, electrical systems, fire suppression, alarms, security,  
3 and to add IT infrastructure. Additional costs of \$2.2 million for this project are  
4 forecasted in 2025.

5

6 Projects with expenditures in 2025 and 2026 include \$4.8 million to repair and  
7 replace elevators at the Belle River power plant (line 1); \$2.3 million to complete  
8 the replacement of the roof at the Greenwood Energy Center (line 2); \$0.8 million  
9 to complete the replacement of the substation and related distribution equipment at  
10 the Walker Cisler Building (line 3); \$6.7 million to investigate and replace the  
11 substation and electrical distribution equipment that is used to power the downtown  
12 campus (line 4); \$31.3 million for HVAC replacements at various locations  
13 including boilers, chillers, piping, air handlers, diffusers, variable air volume boxes,  
14 and other equipment (lines 5 through 8 and 45); \$2.1 million for electrical work at  
15 various locations (lines 9 and 38); \$3.3 million for required five-year façade  
16 inspection and restoration work on the Walker Cisler Building (WCB) (line 11);  
17 \$7.8 million to optimize the open space at the headquarters complex previously  
18 used by IT and the alternative Merchant Operation Center, and to renew all  
19 plumbing on the first and second floors of the plaza (line 12); \$2.3M to install  
20 furniture, and a structure in the courtyard that will house outdoor AV equipment  
21 and power to enable outdoor activities and events (line 13); \$1.8 million to replace  
22 automotive lifts (line 34), and \$2.2 million to complete the Warren Service Center  
23 Transformer Yard reorganization and infrastructure improvements (line 10),  
24 previously approved in Case Nos. U-21297 and U-21534.



Line  
No.

1 Finally, the projected periods include \$17.6 million for other general construction  
2 and end-of-life repairs and replacements, including but not limited to, equipment,  
3 tools, plumbing, and overhead cranes.

4

5 **Q122. What is Service Center Optimization and Modernization on line 3?**

6 A122. Service Center Optimization and Modernization is a project to replace facilities that  
7 have exceeded their useful life by consolidating some sites and updating other  
8 existing sites to reduce the Company's overall footprint and reduce operating  
9 expenses by 2025. The Commission has consistently approved this initiative since  
10 Case No. U-20162. The capital projects for the historical, bridge and test periods  
11 are detailed in Exhibit A-12, Schedule B5.8, page 3. The older facilities have  
12 experienced increased costs due to aging infrastructure, and critical components  
13 such as HVAC and roofs have failed. Many of the projects have been completed,  
14 including the Waterford Service Center which was supported and approved in prior  
15 rate cases. The Warren Service Center project was also supported and approved in  
16 prior rate cases.

17

18 The Western Wayne Service Center project on line 1 is on-going with a cost of  
19 approximately \$25.9 million. Of this amount, \$22.0 million was approved in prior  
20 cases. The building was constructed in 1978 and many building systems such as  
21 lighting, plumbing, electrical, flooring, and ceilings are beyond their useful life and  
22 need replacing. The building renovation (Phase 1, approximately \$15.9 million) is  
23 substantially complete and \$14.4 million was previously approved in Case No. U-  
24 21534. Approximately \$1.5 million to repurpose the former Alternative System  
25 Operations Center (ASOC) into office space is planned for 2025. Phase 2 of this

Line  
No.

1 project includes expanding the fleet vehicle repair garage bay and improvements to  
2 the fleet garage and warehouse. Phase 2 also includes site improvements for a  
3 parking lot expansion, stormwater management, site lighting, and a perimeter  
4 security fence. Total projected costs for Phase 2 are \$10.0 million, of which \$7.6  
5 million was approved in Case No. U-21534.

6

7 The Company is also planning to invest \$5.1 million in 2025 and 2026 (lines 2 and  
8 3) to update the technical development center in Westland, which is nearly 50 years  
9 old with many assets in need of repair. The scope of the repairs includes replacing  
10 the current storm water management system due to flooding which has affected  
11 training and property utilization; replacing parking lots; and replacing building  
12 systems including HVAC, roof, and electrical systems. The Company previously  
13 requested \$7.9 million for this project, but a portion of the work will be re-timed to  
14 future years.

15

16 The Company is now planning \$7.8 million (line 4 and 5) to renovate the second  
17 floor of the Trombly Service Center to meet ADA compliance standards, and to  
18 clear adjacent land at the Trombly site for future use. It also will spend \$2.4 million  
19 to extend the parking lot at the Caniff Service Center (line 6). The Caniff parking  
20 lot is overcrowded and does not have enough parking spaces. This has led to cars  
21 and work trucks parking on the side of the roadway and on the grassy water  
22 detention area. The Company had requested funding of \$9.4 million for 2025 water  
23 system improvements and automated building control system upgrades for various  
24 service centers in U-21534 but has since determined that the work required at

Line  
No.

1 Trombly and Caniff are a higher priority and has deferred the water system and  
2 building control system projects.

3

4 **Q123. What are the projects in Security Measures on line 4 of Exhibit A-12, Schedule**  
5 **B5.8 page 1?**

6 A123. Line 4 on page 1 includes a project to reduce security related risks that was  
7 approved in Case No. U-21534. It reflects \$7.0 million in 2025 and 2026 for Phase  
8 III of a project started in 2019 to replace the existing physical access control system  
9 (PACS) with new technology. Line 4 also includes \$838,000 in each year of the  
10 projected period for the on-going replacement of physical security assets as they  
11 age. The amounts for 2024 and 2025 were approved in Case No. U-21534.

12

13 **Q124. What items are included in line 5, Miscellaneous?**

14 A124. The capital expenditures within the net amount on line 5 are substantially offset by  
15 investment recovery salvage sales. The expenditures include approximately \$1.7  
16 million 2026 for environmental management. (Costs for 2024 and 2025 were  
17 approved in Case No. U-21534.) The Company is evaluating and developing  
18 technologies and controls to provide cost effective solutions in meeting  
19 environmental compliance and energy requirements. The remaining balance is for  
20 minor capital items used in the Corporate Staff groups.

21

22 **Q125. How much allowance for funds used during construction (AFUDC) is assumed**  
23 **in the projected test period for Corporate Staff?**

24 A125. AFUDC for Corporate Staff is included in Exhibit A-12, Schedule B5.8 page 4. As  
25 shown, the Corporate Staff AFUDC is projected to be \$3.9 million for the 12-month

Line  
No.

1 period ending December 31, 2026. A historical trend is used to estimate AFUDC  
2 on routine capital, such as the portion of Facilities, Design and Construction where  
3 the mix of eligible projects is consistent year to year, while AFUDC is calculated  
4 specifically on a project-by-project basis for eligible non-routine projects. The  
5 authorized cost of capital rate is 5.69% per the January 23, 2025 Order in Case No.  
6 U-21534.

7

8 **Q126. What is provided on the schedule entitled Removal Costs, Plant in Service and**  
9 **CWIP on page 5 of Exhibit A-12, Schedule B5.8?**

10 A126. This schedule provides a breakdown of plant activities which are used to forecast  
11 Plant in Service, Accumulated Depreciation and Construction Work in Progress  
12 (CWIP) on the projected balance sheet. Capital expenditures consistent with page  
13 1 are summarized in columns (c) through (f). Column (b) includes a corresponding  
14 in-service assumption: "Annual" is indicated for categories of plant spend that are  
15 generally unitized within the year of spend, while a specific in-service date is used  
16 for projects that remain in CWIP for more than a year before moving into Plant in  
17 Service.

18

19 Column (g) includes an estimated percentage of removal costs that are included  
20 within the capital expenditures. Removal costs are charged to Accumulated  
21 Depreciation rather than Plant/CWIP and are therefore not depreciable.  
22 Decommissioning projects on line 3 are charged 100% to accumulated  
23 depreciation. Removal cost of 10% based on historical trend of removals as a  
24 component of capital expenditures is applied to Facilities Repairs and  
25 Replacements on line 2, Facilities Construction and Upgrade on line 4, and Service

Line  
No.

1 Center Optimization Projects on lines 8 through 16. Finally, Investment Recovery  
2 salvage sales are assigned 100% removal as these proceeds are credited directly to  
3 Accumulated Depreciation to offset removal charges.

4  
5 Columns (h) through (j) reflect calculated removal costs based on projected Capital  
6 Expenditures in columns (d) through (f) multiplied by the removal cost percentage  
7 in column (g). The remaining Capital Expenditures will appear in Plant in Service  
8 columns (k) through (m) if in-service assumption is "Annual," or CWIP columns  
9 (n) through (p) until the date of in-service as indicated in column (b). At that time,  
10 cumulative spending, including the historical period is transferred to in-service  
11 (excluding the removal cost estimate).

12

13 **Balance Sheet Forecast**

14 **Q127. What projected test year balance sheet information are you providing?**

15 A127. Exhibit A-12, Schedules B2 and B3 provide the projected 13-month average utility  
16 plant balances and depreciation reserves, respectively, compared to the historical  
17 period. Schedule B4 provides the projected 13-month average working capital  
18 compared to the historical period. Schedule B4.1 classifies the projected balance  
19 sheet information into the categories of net plant, working capital, and the various  
20 financing components.

21

22 **Q128. Can you explain the DTE Electric balance sheet on Schedule B4.2?**

23 A128. The electric balance sheet statement shown on Exhibit A-12, Schedule B4.2,  
24 represents the DTE Electric 13-month average balance sheet for the projected year.

Line  
No.

1   **Q129. What are the major components making up the Assets and Other Debits**  
2       **reflected in Exhibit A-12, Schedule B4.2, page 1 of 2?**

3   A129. Exhibit A-12, Schedule B4.2, page 1 of 2 has four major asset components:

- 4       1)     Total Utility Plant and Property  
5       2)     Other Property and Investments  
6       3)     Current Assets  
7       4)     Deferred Debits

8

9   **Total Utility Plant and Property**

10   **Q130. How did you develop the projected Utility Plant and Property amount in this**  
11       **case?**

12   A130. Total Utility Plant and Property on Exhibit A-12, Schedule B4.2 (lines 4 through  
13       13) is comprised primarily of Net Utility Plant (line 9), which is projected to  
14       increase each year resulting from annual capital expenditures being greater than the  
15       annual depreciation allowance charge, partially offset by the transfer of \$2.1 billion  
16       to a regulatory asset related to the Monroe power plant, and the securitization of  
17       \$233 million of coal assets at the Belle River power plant, as required by the  
18       Commission's Order in the Company's 2023 IRP proceeding, Case No. U-21193.  
19       These projections reflect substantial capital expenditures primarily related to  
20       distribution system replacements and reliability improvements, steam generation  
21       reliability and environmental projects, nuclear main unit generator replacement and  
22       maintenance projects, facility upgrades and maintenance, and information  
23       technology investments. Page 1 of Exhibit A-12, Schedule B5 provides a  
24       functional summary of DTE Electric's total projected capital expenditures. Further,

Line  
No.

1 the various operational witnesses provide details on the capital expenditures they  
2 are sponsoring.

3

4 **Q131. How did you develop the projected capital expenditure amounts DTE Electric**  
5 **included in this case?**

6 A131. To determine the projected test year capital expenditure levels for this case, DTE  
7 Electric started with historical amounts normalized for unusual, non-recurring  
8 items. In some cases, the routine capital expenditures were escalated for the effects  
9 of inflation. Capital expenditures for unique or one-time projects were individually  
10 forecasted. Capital expenditures are supported by Company Witnesses Guillaumin,  
11 Milo, Davis, Hill, Rademacher, Steudle, Stowe, Robinson, Hartley, Leuker, Foley,  
12 Ambrose, and me. (Removal costs included in capital expenditures on the  
13 individual witness exhibits are reflected as a charge to the accumulated depreciation  
14 reserve.)

15

16 **Q132. Will all the forecasted capital expenditures be unitized to plant in service by**  
17 **the end of the projected test period?**

18 A132. No. The capital expenditure exhibits show which projects will not be in service  
19 during the projected test period. There is no depreciation expense projected for  
20 these projects, and the AFUDC credit on the income statement offsets the impact  
21 of reflecting the projects in rate base. In other words, there is no current revenue  
22 requirement for these projects.

23

24 **Q133. What are Removal Costs?**

Line  
No.

1 A133. Pursuant to the Electric Plant Instructions in the Uniform System of Accounts  
2 (USOA), cost of removal means the cost of demolishing, dismantling, tearing down  
3 or otherwise removing electric plant. As part of Utility plant accounting, the  
4 Company's depreciation rates are set to recover both the original cost and estimated  
5 removal costs over the life of the asset. When removal costs are actually incurred,  
6 they are charged against the accumulated depreciation balance. Any over or under  
7 accrual is handled by updating depreciation rates in depreciation cases and applying  
8 the new depreciation rates prospectively when they are reflected in base rates.

9

10 **Q134. What is included on page 2 of Exhibit A-12, Schedule B5?**

11 A134. To calculate the projected balance sheet, the rate case model appropriately assumes  
12 the portion of capital expenditures related to removal work is charged as a debit to  
13 accumulated depreciation. These costs do not get charged to CWIP/Plant and are  
14 not depreciable capital expenditures. The schedule on page 2 of Exhibit A-12,  
15 Schedule B5, shows the amount of removal costs included in capital expenditures  
16 on page 1.

17

18 Capital expenditures from Page 1 are summarized on lines 1 through 13. Removal  
19 Costs included within those Capital Expenditures are provided on lines 15 through  
20 27 which are assumed charged to Accumulated Depreciation. The difference on  
21 lines 29 through 41 represents the non-removal portion of capital expenditures  
22 initially charged to CWIP and moved to Gross Plant once placed in service.

23

24 **Q135. What is provided on pages 3-4 of Exhibit A-12, Schedule B5?**



Line  
No.

1 A135. This schedule provides the Company Summary breakdown of plant activities used  
2 to forecast Plant in Service, Accumulated Depreciation and Construction Work in  
3 Progress (CWIP) on the projected balance sheet. Witnesses Guillaumin, Davis,  
4 Hill and I sponsor a similar schedule for Steam, Nuclear, Distribution and  
5 Corporate Staff, respectively, which is displayed on lines 1 through 31, and 46  
6 through 47. On lines 33 through 43 of this summary schedule, I also provide the  
7 corresponding activity for Information Technology, Fuel Supply, Community  
8 Lighting, Demand Side Management, and Charging Forward based on assumptions  
9 provided by the sponsoring witnesses.

10

11 Capital expenditures consistent with page 1 are summarized in columns (d) through  
12 (f). Column (g) through (i) includes estimated removal costs that are included  
13 within those capital expenditures. To estimate cost of removal, the Company  
14 assumes a standard percentage of capital expenditures related to removal costs,  
15 unless the project is 100% related to removal or demolition or 0% removal related  
16 to technology projects. The remaining Capital Expenditures will appear in Plant in  
17 Service columns (j) through (l) if assumed in-service, or CWIP columns (m)  
18 through (o) until transferred to in-service.

19

20 **Q136. What is the projected change in Total Utility Plant and Property?**

21 A136. Exhibit A-12, Schedule B4.2, line 4, reflects a plant-in-service decrease from  
22 December 2023 to December 2025 of \$658.0 million. This change is due to  
23 \$3,808.6 million of base capital in-service movement, less \$3,519.9 million related  
24 to the Monroe regulatory asset reclassification, and \$946.7 million of plant  
25 retirements transferred to the depreciation reserve. The plant-in-service change

Line  
No.

1 from December 2025 to December 2026 is \$2,332.6 million. This change is due to  
2 \$3,080.1 million of in-service movement, less \$747.5 million for plant retirements.

3  
4 Plant held for future use on line 5 primarily reflects the FERMI 2 license extension  
5 in the historical and interim periods. The license extension becomes effective when  
6 the existing license expires on March 20, 2025, and is reclassified to intangible  
7 plant within Plant in Service. (See Exhibit A-13, Schedule C6, page 2, line 21.)  
8 The costs incurred to obtain the extension have been capitalized and include project  
9 management; engineering planning and design; and NRC required inspections of,  
10 and updates to, the physical assets. DTE Electric will incur additional costs through  
11 March 2025 to complete work related to commitments made to the NRC as a  
12 condition of obtaining the extension. The license extension will be amortized over  
13 its 20-year service life starting in 2025.

14  
15 The CWIP change on line 6 from December 2023 to December 2025 is an increase  
16 of \$668.8 million. This change is primarily due to \$4,413.6 million of capital  
17 expenditures offset by \$3,744.8 million of projects transferred to plant-in-service.  
18 The CWIP decrease from December 2025 to December 2026 of \$646.9 million  
19 reflects \$2,433.2 million of capital expenditures, less transfers to plant-in-service  
20 of \$3,080.1 million. As can be seen on Exhibit A-12, Schedule B5, projected  
21 capital expenditures are over \$2.5 billion annually. The largest capital expenditures  
22 are related to distribution and production assets. Witness Guillaumin supports the  
23 steam production investments including plant reliability and safety, coal ash  
24 projects, decommissioning work, and battery projects. Witnesses Hill, Robinson,  
25 Stowe, and Rademacher support distribution investments including emergent

Line  
No.

1 replacements, customer connections, infrastructure hardening and redesign, and  
2 technology.

3

4 The decrease in acquisition adjustments on line 7 from December 2023 to  
5 December 2026 of \$17.4 million results from amortization of the adjustment for the  
6 Renaissance Power plant.

7

8 The decrease in depreciation reserve on line 8 from December 2023 to December  
9 2025 of \$664.1 million is due to a \$1,418.1 million Monroe regulatory asset reclass,  
10 \$627.7 million of removal costs and \$946.6 million of plant retirements, offset by  
11 \$2,328.4 million of depreciation expense. The increase of \$348.1 million from  
12 December 2025 to December 2026 represents depreciation expense of \$1,196.9  
13 million partially offset by \$334.3 million of removal costs and \$747.5 million of  
14 plant retirements. It also reflects the removal of a debit balance of \$233.0 million  
15 representing the net book value of the Belle River coal assets remaining after the  
16 assets are retired in 2025 and 2026. This remaining net book value is assumed to  
17 be securitized in December 2026.

18

19 The change in Nuclear Fuel Property on line 12 from December 2023 to December  
20 2025 is an increase of \$19.6 million from nuclear fuel purchases of \$134.4 million  
21 less nuclear fuel expense of \$114.8 million. The change in Nuclear Fuel Property  
22 from December 2025 to December 2026 is a decrease of \$55.9 million primarily  
23 due to fuel expense. Witness Davis supports the nuclear fuel purchase amounts.

24

25 **Q137. Why is CWIP included in Net Utility Plant for ratemaking purposes?**

Line  
No.

1 A137. CWIP is included in this rate filing as required by the Commission's May 10, 1976  
2 Order in Case No. U-4771. CWIP is forecasted (in part) based on the expected in-  
3 service date for large projects, when they are reclassified from CWIP to Plant in  
4 Service. These projects generally include AFUDC, which is credited on the income  
5 statement, reducing the revenue deficiency, and offsetting the impact of the assets  
6 in rate base. AFUDC is applied to projects greater than \$50,000 and lasting more  
7 than six months, with an exception for environmental and other specifically ordered  
8 projects.  
9  
10 Per the Commission's March 14, 1980, Order in Case No. U-5281, a generic  
11 proceeding on the Commission's own motion to examine the accounting treatment  
12 of CWIP and AFUDC, the Commission required that pollution control related  
13 CWIP should not accrue AFUDC but instead be included in rate base. This position  
14 was affirmed in the Commission's August 16, 2011, Order in Case No. U-15244  
15 (page 72).  
16  
17 CWIP also includes lower cost, short duration projects that are not eligible for  
18 AFUDC. Projects involving smaller dollar assets, or mass assets, are initially  
19 charged to CWIP but are soon transferred to Plant in Service. The type of work  
20 included in the short duration items is generally standard and ongoing throughout  
21 the year. Thus, as the prior balance for these types of assets is cleared to Plant in  
22 Service, another wave of construction is adding new amounts to the CWIP balance.  
23 For these types of recurring items, I forecasted CWIP based on a historical trend of  
24 balances in the account.

Line  
No.

1 **Other Property and Investments**

2 **Q138. What are you forecasting for Other Property and Investments?**

3 A138. Lines 16 and 17 are held constant at the historical 13-month average. As previously  
4 discussed, the Nuclear Decommissioning Trust Fund balance on line 18 was  
5 eliminated from the historical period because it does not impact base rates.

6

7 **Current Assets**

8 **Q139. What is included in Current Assets on lines 21 through 32 of Exhibit A-12,**  
9 **Schedule B4.2?**

10 A139. Current assets include cash, notes and accounts receivable, uncollectible reserve,  
11 unbilled revenues, fuel inventories, materials and supplies inventories,  
12 prepayments, and other current assets.

13

14 **Q140. How did you forecast the balance for the various Current Assets?**

15 A140. Individual line items that fluctuate throughout the year, and for which a specific  
16 forecast is not developed, were based on a 13-month historical average. These  
17 items include cash, other accounts receivable, uncollectible reserve, unbilled  
18 revenues, and materials and supplies inventory. Notes receivable and other current  
19 assets were adjusted to zero at December historical and no changes were assumed  
20 in the projected period. Customer accounts receivable was also based on a 13-  
21 month average historical with additional forecast adjustments. Fuel inventory and  
22 prepayments were specifically forecasted.

23

24 **Q141. How did you forecast the balance for Customer Accounts Receivable on line**  
25 **24?**

Line  
No.

1 A141. Customer Accounts Receivable was based on a 13-month weather normalized  
2 historical average, adjusted for rate relief approved in Case Nos. U-21297 and U-  
3 21534.

4

5 **Q142. How did you forecast the balance for Fuel Inventory on line 29?**

6 A142. The decrease in Fuel Inventory from the historical period reflects the retirement of  
7 Belle River Power Plant in 2026.

8

9 **Q143. How did you forecast the balance for Prepayments on line 31?**

10 A143. Prepayments primarily represent property taxes. The change is based on forecasted  
11 accruals and payments. The historical period also included prepaid software  
12 contracts that will be amortized during 2024 and 2025.

13

14 **Deferred Debits**

15 **Q144. What is included in Deferred Debits on lines 35 through 70 of Exhibit A-12,**  
16 **Schedule B4.2?**

17 A144. This section contains various regulatory assets and deferred tax items.  
18 Unamortized Debt Expense on line 35 is increased by projected issuance expense  
19 of \$21.3 million assumed at 1% of new debt issues offset by annual straight-line  
20 amortization of approximately \$5.9 million. Unamortized Loss on Reacquired Debt  
21 on line 36 is reduced by annual straight-line amortization of approximately \$2.6  
22 million. These balances are tied to specific debt issues and are amortized over the  
23 life of the issues.

24

25 **Q145. What is the prepaid pension asset on line 38?**

Line  
No.

1 A145. Pension costs recognized by the Company are reflected in a pension liability  
2 account. However, when contributions to the pension trust are made, they reduce  
3 the liability. To date, the Company has funded more than it has recorded as a  
4 pension liability, resulting in a net debit balance, referred to as the prepaid pension  
5 asset. The prepaid pension asset represents the cumulative difference between the  
6 pension cost recognized by the Company and the Company's contribution to its  
7 pension trust. Specifically, when the Company's annual contributions exceed  
8 annual pension cost, the prepaid pension asset increases; and when the Company's  
9 annual contributions are less than the annual pension costs, the prepaid pension  
10 asset decreases. The pension plans and related pension costs are explained by  
11 Witness Fix.

12

13 **Q146. Does the prepaid pension asset reflect any funding during the projected**  
14 **period?**

15 A146. Yes, it includes a transfer of pension assets of \$25 million from the DTE Gas non-  
16 union plan in 2025 and in 2026.

17

18 **Q147. Why will DTE Gas transfer \$50 million to the DTE Electric pension plan?**

19 A147. As of December 31, 2023, the DTE Gas Non-Union pension plan had assets in  
20 excess of its projected benefit obligation (PBO) of about \$110 million, whereas the  
21 DTE Electric pension plan had assets that were about \$334 million less than its  
22 PBO. Since the DTE Gas Non-Union pension plan is a component of the overall  
23 DTE Energy Retirement plan, as is the DTE Electric pension plan, the Company  
24 can transfer the excess assets in the DTE Gas Non-Union plan to DTE Electric  
25 without any income tax or ERISA consequences. Funding the pension plan

Line  
No.

1 increases the return generated from plan assets, which will reduce pension costs  
2 over time. This transfer will be accomplished through a payment by DTE Electric  
3 of \$25 million in 2025 and 2026 to DTE Gas in consideration for the transfer of  
4 DTE Gas trust assets of \$25 million in 2025 and 2026 within the DTE Energy  
5 Retirement plan trusts.

6

7 **Q148. What is the Reg Asset – Pension Deferral on line 40 of Exhibit A-12, Schedule**  
8 **B4.2?**

9 A148. The regulatory asset was established pursuant to the Commission’s order in Case  
10 No. U-20836 that approved a pension expense deferral mechanism. Effective with  
11 the Order, actual pension expense is deferred as a regulatory asset if positive or a  
12 regulatory liability if negative. The regulatory asset balance reflects the deferral of  
13 the Company’s projected pension expense as further described by Witness Fix.

14

15 **Q149. Why is there an item called “Monroe Regulatory Asset” on line 41 of Exhibit**  
16 **A-12, Schedule B4.2?**

17 A149. As previously discussed, the July 26, 2023 Order in the Company’s IRP in Case  
18 No. U-21193 requires (among other things) the Company to securitize  
19 approximately \$812 million after the retirement of the Monroe Power Plant,  
20 expected in 2032. The portion of the plant to be securitized will remain classified  
21 within plant in service until it is retired. The balance of the plant not being  
22 securitized is to be recovered as a regulatory asset over fifteen years.

23

24 **Q150. Why does the Monroe Regulatory Asset have a zero balance on line 41?**



Line  
No.

1 A150. The Order in Case No. U-21193 requires the overall return on the regulatory asset  
2 to reflect a return on equity of 9%. To accomplish this, I have excluded the  
3 regulatory asset from the balances underlying the base rate revenue deficiency  
4 calculations. A separate rate of return for the Monroe regulatory asset is supported  
5 by Witness Vangilder on Exhibit A11, Schedule A1.2.

6

7 **Q151. How was the Monroe Regulatory Asset balance calculated?**

8 A151. Refer to Exhibit A-12, Schedule B4.5. The total Monroe plant balance forecasted  
9 for January 31, 2025 is \$3.1 billion as shown in column (a), line 9. To determine  
10 how much of this should be reclassified to the regulatory asset, I had to subtract the  
11 amount that will remain in plant and eventually be securitized after the plant is  
12 retired in 2032. Lines 12 through 17 calculate the plant amount that will result in  
13 the securitization value of \$812 million in 2032. That amount is \$1.0 billion as  
14 shown on line 17. The \$1.0 billion will remain in plant and be depreciated at 2.82%  
15 based on authorized depreciation rates. This results in a net plant balance of \$812  
16 million on December 31, 2032, as proven out in columns (c) through (k).  
17 Subtracting the \$1.0 billion to be securitized from the \$3.1 billion total net plant  
18 balance, results in the \$2.1 billion net plant amount to be reclassified to the  
19 regulatory asset, as shown in column (b). This amount is carried to Exhibit A-12,  
20 Schedule B4.4, line 3.

21

22 **Q152. Why did you use the Monroe balance forecasted through January 31, 2025?**

23 A152. The settlement in the IRP Case No. U-21193 anticipated that the Monroe regulatory  
24 asset would be calculated using a December 31, 2024, balance, and depreciation on  
25 the amount to be reclassified would cease effective January 1, 2025. The

Line  
No.

1 underlying assumption was that the rate case (U-21534) would be effective in  
2 January 2025. However, new rates from Case No. U-21534 did not become  
3 effective until February 2025. Therefore, depreciation on the full \$4.5 billion of  
4 gross plant was still being collected in base rates during January 2025. After the  
5 reclassification, the remaining plant being depreciated is only approximately \$1.0  
6 billion, a reduction in gross plant of approximately \$3.5 billion. This can be seen  
7 on Exhibit A-12, Schedule B4.5, line 6, column (b). The impact to depreciation  
8 expense for one month is approximately \$8 million, which the Company considered  
9 material. Therefore, to ensure that actual depreciation recorded in expense was  
10 consistent with the amount being collected in base rates, the Company delayed the  
11 reclassification until January 31, 2025.

12  
13 **Q153. How is the Monroe regulatory asset calculated on Exhibit A-12, Schedule**  
14 **B4.4?**

15 A153. The beginning balance on line 3 is carried from Exhibit A-12, Schedule B4.5. In  
16 column (c), capital additions and amortization for 2026 are shown on lines 5 and 6.  
17 Per the Case No. U-21193 July 26, 2023 IRP Order, capital additions approved in  
18 rate cases will be added to the regulatory asset. Witness Guillaumin supports the  
19 capital expenditures which are shown on Exhibit A-12, Schedule B5.1, page 2. The  
20 amortization is calculated based on a fifteen-year period per the Case No. U-21193  
21 July 26, 2023 IRP Order. After reflecting the additions and amortization, the  
22 projected ending balance for 2026 is shown on column (d), line 7. The thirteen-  
23 month average is shown in column (f). The thirteen-month average from column  
24 (f) line 8 is used by Witness Vangilder on his Exhibit A-11, Schedule A1.2 to  
25 calculate the return.

Line  
No.

1 **Q154. What is the Ludington Regulatory Asset on line 42 of Exhibit A-12, Schedule**  
2 **B4.2?**

3 A154. On May 18, 2023 the Commission approved a joint application by DTE Electric  
4 and Consumers Energy in Case No. U-21310 to defer certain costs at the Ludington  
5 Pumped Storage Plant resulting from defective work by a third party. The balance  
6 represents costs deferred during 2023 and 2024 after receipt of the Order.

7

8 **Q155. How was the Customer 360 Regulatory Asset on line 44 developed?**

9 A155. The Company implemented a new Customer Relationship and Billing system in  
10 April 2017 called Customer 360. Pursuant to the September 26, 2016 Order in Case  
11 No. U-17666, the Company deferred \$47 million for certain project expenses in  
12 Account 182.3, Other Regulatory Assets. The Company also incurred \$16.6  
13 million of post implementation costs during 2017. The Commission approved  
14 recovery of the 2017 amount in Case No. U-20162. The deferred costs are being  
15 amortized over a 15-year period, and the balance reflects annual amortization of  
16 about \$4.2 million.

17

18 **Q156. What is the Residential Income Assistance regulatory asset on line 46?**

19 A156. In Case No. U-20561, the Commission authorized DTE Electric to defer Residential  
20 Income Assistance (RIA) and Low-Income Energy Assistance credits above a base  
21 amount. The balance reflects that in 2023, the Company issued more RIA credits  
22 to customers than were reflected in the base. In Case No. U-20836, the Commission  
23 ordered any unspent RIA and LIA be recorded as a regulatory liability. Effective  
24 with the Order in U-20836, any underspent amounts will be netted against any  
25 regulatory assets recorded for overspent amounts. The projected balances were

Line  
No.

1 based on year end 2024. I am seeking approval for the recovery of this regulatory  
2 asset over five years. The projected amortization is included in revenue on Exhibit  
3 A-13, Schedule C3, page 2, line 2.

4

5 **Q157. What is the Program Evaluation & Review Committee (PERC) regulatory**  
6 **asset on line 47?**

7 A157. This balance represents deferred costs for certain nuclear O&M projects. As further  
8 explained by Witness Davis, the Company executes PERC operations and  
9 maintenance projects. The change in balance is projected based on the addition of  
10 deferred costs less the amortization of deferred amounts over five years, as shown  
11 on my Exhibit A-13, Schedule C5.17. As previously discussed, the Order in Case  
12 No. U-18014 provided deferral treatment for any expenses over or under a \$4.9  
13 million base amount, and the base was increased to \$15 million in Case No. U-  
14 20561.

15

16 **Q158. What is the Advanced Distribution Management System (ADMS) regulatory**  
17 **asset on line 48?**

18 A158. As previously discussed, the Company is installing an ADMS. The Commission  
19 approved deferral of certain O&M costs as a regulatory asset with amortization over  
20 fifteen years in Case No. U-20162. As shown on Exhibit A-12, Schedule B5.4,  
21 page 1 of 23, line 25, the final deferral of these expenses was \$3.4 million in the  
22 2023 historical year. The regulatory asset balance is reduced by annual amortization  
23 of approximately \$1.2 million in 2024 through 2026.

24

25 **Q159. What is the Charging Forward Regulatory Asset on line 49?**

Line  
No.

1 A159. As previously discussed, in Case Nos. U-20162 and U-20935 the Commission  
2 approved a program called Charging Forward to encourage third parties to build  
3 charging stations for electric vehicles by providing rebates. Per the Order, the  
4 regulatory asset will be expensed over five years, concurrent with its inclusion in  
5 base rates. Additionally, the Company requested, and received approval for, an  
6 expansion of the Charging Forward program in Case Nos. U-20836 and U-21297.  
7 The Orders provide for regulatory asset treatment for rebates paid to schools,  
8 municipalities, gas stations, and similar customers. The projected balance of \$68.7  
9 million at December 2026 reflects deferred expense through the projected period,  
10 supported by Witness Foley, less cumulative amortization.

11

12 **Q160. What is the Advanced Customer Pricing Pilot Regulatory Asset on line 51?**

13 A160. Regulatory Asset treatment for certain implementation costs for the ACPP was  
14 approved in the Commission's November 14, 2019 Order in Case No. U-20602.  
15 The Commission approved deferral of up to \$7.3 million of costs. Actual costs  
16 deferred totaling \$6.6 million through 2022 are supported by Witnesses Foley and  
17 Sparks on Exhibit A-13, Schedule C5.9.2, less cumulative amortization.

18

19 **Q161. What is the Time of Day (TOD) Regulatory Asset on line 52?**

20 A161. Regulatory Asset treatment for certain implementation costs for the Company's  
21 Time of Day rate offering was approved in the Commission's November 18, 2022  
22 Order in Case No. U-20836. The Company proposed a full implementation of TOD  
23 rates, and the project incurred both capital and O&M expenses. The balance as of  
24 December 2026 on line 52 of \$3.2 million reflects \$8.4 million of one-time  
25 implementation costs offset by \$5.2 million of cumulative amortization expense

Line  
No.

1 through the projected period. Witnesses Foley and Sparks support one-time  
2 implementation costs on Exhibit A-13, Schedule C5.9.2.

3

4 My Exhibit A-13, Schedule C5.9.3 supports the calculation of annual amortization  
5 expense of \$3.0 million for both the ACPP and TOD regulatory assets, which is  
6 included in Customer Service O&M expense supported by Witness Sparks.

7

8 **Q162. What is the Pension Capitalized on line 54?**

9 A162. As previously described regarding pension expense, this balance represents the  
10 capitalized non-service cost components of pension expense. Because the non-  
11 service costs became negative, the deferred balance was a regulatory liability by  
12 the end of 2023 and is shown on line 112.

13

14 **Q163. What is the Demand Response Regulatory Asset on line 55?**

15 A163. Witness Farrell describes the Company's Demand Response programs and the  
16 reconciliation process. The Commission has approved recovery of DR costs and  
17 incentives for the years 2019 through 2021 via inclusion of amortization expense  
18 in base rates and I am requesting amortization of the 2022 and 2023 layers in the  
19 instant case. The balance reflects a settlement in the DR 2022 Reconciliation Case  
20 No. U-21403, of \$3.8 million approved by Order on March 15, 2024; and a  
21 settlement in the DR 2023 Reconciliation Case No. U-21658, approved on February  
22 27, 2025, reflecting a regulatory liability of \$1.8 million and \$0.5 million of  
23 incentives. The projected \$2.9 million balance on line 55 reflects the cumulative  
24 deferrals for the 2019 through 2023 layers, offset by accumulated amortization.  
25 Amortization of the deferred over/under collected amounts is reflected on Exhibit

Line  
No.

1 A-13, Schedule C6, line 9. Amortization of the accrued incentives is reflected on  
2 Exhibit A-13, Schedule C3, page 2, line 3.

3

4 **Q164. What is the Incentive Compensation Regulatory Asset on line 56?**

5 A164. In Case No. U-20836, the Commission approved a recovery mechanism for  
6 incentive compensation related to operating metrics that provided for deferral  
7 treatment above or below the base amount, up to a maximum 100% target level, to  
8 be refunded or recovered in DTE Electric's next rate case. A regulatory asset was  
9 deferred for 2022, but the projected balance is a regulatory liability as discussed in  
10 detail in the liability section of my testimony.

11

12 **Q165. Do you recommend that the incentive compensation deferral mechanism be**  
13 **continued?**

14 A165. Yes, I request the deferral be continued and that the base amount be reset equal to  
15 the amount of incentive compensation approved for recovery in base rates in this  
16 case.

17

18 **Q166. What modifications to the incentive compensation mechanism are you**  
19 **proposing?**

20 A166. The deferral should cover the total actual payout, including amounts above 100%  
21 of the target. As described in more detail by Witness Fix, the incentive program  
22 allows for a range of payouts from zero to 200% of target. The incentive plan is  
23 designed to motivate employees to achieve results beyond the target, further  
24 improving organizational performance and benefitting customers. Since the

Line  
No.

1 Company must provide a refund to customers if results fall below the baseline, it is  
2 reasonable to include the cost of achieving exceptional results.

3

4 **Q167. What is the Low-Income Assistance Tracker on line 57?**

5 A167. In Case No. U-20561, the Commission authorized DTE Electric to defer Residential  
6 Income Assistance (RIA) and Low-Income Energy Assistance credits above a base  
7 amount. In 2023, the Company issued less LIA credits to customers than were  
8 reflected in the base. The difference is deferred to a regulatory liability and is shown  
9 on line 114. In Case No. U-20836, the Commission ordered any unspent RIA and  
10 LIA be recorded as a regulatory liability. Effective with the Order in U-20836, any  
11 underspent amounts will be netted against any regulatory assets recorded for  
12 overspent amounts.

13

14 **Q168. What is the Low-Income Payment Stability Plan regulatory asset on line 58?**

15 A168. In Case No. U-20929, the Commission authorized DTE Electric to defer costs  
16 associated with its low-income customer assistance pilot (the Payment Stability  
17 Plan or "PSP"). The PSP pilot creates a fixed maximum bill for participating  
18 customers based on their income, rather than providing a fixed credit amount on a  
19 variable bill like those provided by the residential income assistance or low-income  
20 assistance programs. The balance consists of supplemental payments, arrears  
21 forgiveness, and benefit awards. I am seeking approval for the recovery of this  
22 regulatory asset over two years.

23

24 **Q169. What is causing the increase in Prepaid OPEB on line 62?**



Line  
No.

1 A169. The Prepaid Post-Retirement Benefit asset increases from \$154.2 million on  
2 December 2023 to \$227.5 million by December 2026. The year-to-year changes  
3 are primarily the result of negative OPEB expense as explained by Witness Cooper.  
4

5 **Q170. Can you explain the tax items on lines 59, 65 and 66 of Exhibit A-12, Schedule**  
6 **B4.2?**

7 A170. Witness Wisniewski supports these tax-related assets. Line 59 represents the  
8 excess deferred taxes that were remeasured related to the reduction of the federal  
9 corporate income tax rate change resulting from the 2017 Tax Cuts and Jobs Act  
10 (TCJA). Line 65, Miscellaneous Tax Related, represents regulatory assets resulting  
11 from changes in tax law such as Medicare Part D and the Michigan Corporate  
12 Income Tax, reduced each year by amortization of approximately \$24.1 million.  
13 Line 66, Recoverable Income Taxes, reflects a regulatory asset recorded in  
14 conjunction with an offsetting ADFIT liability when ASC 740 (formerly FAS 109)  
15 was adopted in 1993. It has scheduled reductions of \$2.4 million per year supported  
16 by Witness Wisniewski. The ASC 740 balance sheet accounts do not affect the  
17 revenue requirement. This accounting and rate treatment were approved by the  
18 Commission in Case No. U-10083.  
19

20 **Q171. How were Other Deferred Debits on line 70 of Exhibit A-12, Schedule B4.2**  
21 **developed?**

22 A171. The Other Deferred Debits balance includes refundable spent nuclear fuel storage  
23 costs and short-term credit facility costs which were held constant at the 13-month  
24 historical period. It also includes a pre-paid long-term maintenance service  
25 agreement (LTSA) for the Blue Water Energy Center. Changes in the LTSA

Line  
No.

1 balance reflect payments to the service provider, reduced by transfers to capital and  
2 O&M as the services are rendered.

3

4 **Q172. What components make up the Liabilities and Other Credits reflected in**  
5 **Exhibit A-12, Schedule B4.2, page 2 of 2?**

6 A172. Exhibit A-12, Schedule B4.2, page 2 of 2 has four major components:

- 7 1) Capitalization  
8 2) Non-Current Liabilities  
9 3) Current Liabilities  
10 4) Deferred Credits

11

12 **Capitalization**

13 **Q173. How were the projected capitalization amounts determined in this case?**

14 A173. Capitalization (lines 75 through 85) reflects DTE Electric's permanent capital in  
15 the form of long-term debt and common equity. Key long-term debt drivers  
16 include new capital requirements, scheduled debt retirements, refinancing, level of  
17 equity, and the amount of short-term debt. As previously discussed, the regulatory  
18 liability related to the REP is a source of short-term debt. Schedule B4.2, line 78,  
19 shows that long-term debt balances will increase during the forecast periods to  
20 support DTE Electric's increasing asset base, as supported by Company Witness  
21 Lepczyk.

22

23 Common equity balances on line 84 will also increase to finance the growing asset  
24 base and to meet targeted capitalization percentages. Since projected earnings are  
25 insufficient to meet the targeted equity capital percentages, common equity will

Line  
No.

1 need to be funded from additional equity infusions as discussed and supported by  
2 Witness Lepczyk. Projected common equity also reflects dividends required to  
3 sustain and attract equity investors.

4

5 **Q174. What is the projected change in Capitalization?**

6 A174. Exhibit A-12, Schedule B4.2, line 78, reflects a long-term debt decrease from  
7 December 2023 to December 2025 of \$36.0 million primarily due to \$1,621.0  
8 million of new debt issues, less redemptions of \$850.0 million and the removal of  
9 \$809.2 million of debt supporting the Monroe regulatory asset in 2025. The \$7.7  
10 million long-term debt increase from December 2025 to December 2026 is  
11 primarily due to new debt of \$800.0 million, less \$677.0 million of debt  
12 redemptions, and the removal of \$116.5 million of debt supporting the Belle River  
13 coal assets that will be securitized in 2026.

14

15 Line 81 reflects Common Stock increases of approximately \$2,194.0 million  
16 through December 2026 from planned equity infusions as addressed by Witness  
17 Lepczyk. These increases are offset by the removal of \$834.4 million of equity  
18 supporting the Monroe regulatory asset in 2025 and by the removal of \$116.5  
19 million of equity supporting the Belle River coal assets that will be securitized in  
20 2026. A portion of the Common Stock increases may be reduced from additional  
21 equity based on the Commission Order in this case granting the rate relief  
22 requested.

23

24 Line 82, Retained Earnings, increases by \$104.7 million from December 2023 to  
25 December 2025, resulting from net income of \$1,728.1 million, less common

Line  
No.

1 dividend payments of \$1,623.5 million. Retained Earnings decreases from  
2 December 2025 to December 2026 by \$245.8 million resulting from twelve months  
3 ending December 2026 net income of \$695.2 million less common dividend  
4 payments of \$941.0 million. The changes in common equity are reconciled in  
5 Exhibit A-12, Schedule B4.3.

6

7 **Non-Current Liabilities**

8 **Q175. What is included in Non-Current Liabilities on lines 87 through 93 of Exhibit**  
9 **A-12, Schedule B4.2?**

10 A175. This section includes the liability for capital leases and injuries and damages.  
11 Capital leases on line 87 is being held constant and represents the long-term portion  
12 of the liability to offset the Net Capital Lease Property on line 10. The accumulated  
13 provision for injuries and damages on line 89 is being held constant to the 13-month  
14 historical average during the forecast period as new claims and settlements cannot  
15 be predicted.

16

17 **Current Liabilities**

18 **Q176. What is included in Current Liabilities on lines 96 through 105 of Exhibit A-**  
19 **12, Schedule B4.2?**

20 A176. This section includes short-term debt and payables. DTE Electric's short-term debt  
21 balances on line 96 include the balances available from the REP regulatory liability.  
22 The REP regulatory liability represents the temporary over-collection of DTE  
23 Electric's REP surcharge. This liability is used by DTE Electric as an additional  
24 source of financing in base rates. Interest on this liability is paid to our customers

Line  
No.

1 via a credit in the Renewables Plan, lowering the revenue requirement for that  
2 program.

3

4 **Q177. How did you forecast the balance for Accounts Payable on lines 98 and 99?**

5 A177. Accounts payable was forecasted based on a 13-month historical average as of  
6 December 31, 2023.

7

8 **Q178. How did you forecast the remaining current liabilities?**

9 A178. Taxes Payable on line 100 reflects the timing of accruals and payments, as  
10 supported by Witness Wisniewski. The changes in Interest Payable on line 101  
11 also reflect the timing of accruals and payments. Capital Leases Current on line  
12 102 reflects the current portion of the liability to offset the Net Capital Lease  
13 Property on line 10. The fluctuations in line 104, Fermi 2 Outage accrual, result  
14 from forecasted accruals and expenditures for the Fermi 2 planned outages  
15 supported by Witness Davis. Other Current Liabilities on line 105 include vacation  
16 and payroll accruals, customer deposits, and refundable contributions in aid of  
17 construction, and are held constant at the historical 13-month average balance.

18

19 **Deferred Credits**

20 **Q179. What is included in Deferred Credits on lines 108 through 123 of Exhibit A-**  
21 **12, Schedule B4.2?**

22 A179. The December 2023 balance related to line 108 Regulatory Liability - Renewable  
23 Energy Program, was re-classified to short-term debt on my historical Exhibit A-2,  
24 Schedule B6.2. Other Deferred Credits on line 123 includes refundable customer

Line  
No.

1 advances, environmental reserves, and other accrued liabilities held constant at 13-  
2 month average historic levels.

3

4 **Q180. What is the Regulatory Liability – OPEB on line 110?**

5 A180. The OPEB liability was established pursuant to the Commission’s Order in Case  
6 No. U-17767. Consistent with the treatment of pension expense, negative OPEB  
7 expense, less amounts capitalized and transferred, are offset by a regulatory  
8 liability. In Case No. U-21297, the Commission ordered that the Company must  
9 amortize the OPEB regulatory liability of \$128.4 million as of December 2022 over  
10 a seven-year period. The projected balance includes additional deferrals due to  
11 projected negative OPEB expense offset by annual amortization of \$18.3 million.

12

13 **Q181. What is OPEB Capitalized on line 111?**

14 A181. As previously described regarding OPEB expense, this balance represents the  
15 capitalized non-service cost components of OPEB expense.

16

17 **Q182. What is the Pension Capitalized on line 112?**

18 A182. As previously described regarding pension expense, this balance represents the  
19 capitalized non-service cost components of pension expense.

20

21 **Q183. What is the Regulatory Liability – Low-Income Assistance on line 114?**

22 A183. As previously described regarding the Low-Income Assistance Tracker, the  
23 Company issued fewer LIA credits to customers than were reflected in the base in  
24 2023. The projected balance reflects the deferral through December 2024 and offset

Line  
No.

1 by cumulative amortization. The projected amortization is included in revenue on  
2 Exhibit A-13, Schedule C3, page 2, line 2.

3

4 **Q184. What is the Regulatory Liability – Incentives Tracker on line 115?**

5 A184. In Case No. U-20836, the Commission approved a recovery mechanism for  
6 incentive compensation related to operating metrics that provided for deferral  
7 treatment above or below the base amount, up to a maximum 100% target level, to  
8 be refunded or recovered in DTE Electric's next rate case. The continuation of the  
9 mechanism was approved in Case Nos. U-21297 and U-21534. Please refer to  
10 Exhibit A-13, Schedule C5.10.1. Line 3 shows the amounts deferred by calendar  
11 year. A regulatory asset of \$750,000 was deferred for 2022. In 2023, DTE Electric  
12 did not achieve 100% of its target levels based on performance and \$7.5 million,  
13 representing the amount below the approved base of \$12.7 million has been accrued  
14 to a regulatory liability.

15

16 In Case No. U-21297, the Commission set the approved base amount at \$10.1  
17 million, assuming the Company achieved approximately 52% of its targeted  
18 metrics. The Company's accrual for 2024 assumed it would achieve approximately  
19 100%; thus, a deferral was recorded for the difference between the actual results  
20 and the annual base amount of \$10.1 million. This amount from 2024 is netted  
21 against the regulatory liability. In Case No. U-21534, the Commission authorized  
22 the amortization of the 2022 and 2023 deferred amounts over five years. The  
23 projected balance reflects the actual deferral through December 2024 and is offset  
24 by cumulative amortization, assuming the Commission authorizes amortization of  
25 the 2024 layer starting in the projected test period.

Line  
No.

1   **Q185. What is the Regulatory Liability – Demand Response on line 116?**

2   A185. As previously described regarding the DR 2023 Reconciliation Case No. U-21658,  
3       2023 actual spend was lower than authorized by the Commission. The projected  
4       balance reflects the \$1.8 million accrual offset by accumulated amortization of \$0.6  
5       million.

6  
7   **Q186. What are the tax items on lines 119 through 121?**

8   A186. Witness Wisniewski supports lines 119 through 121. Accumulated Deferred  
9       Income Taxes represents timing differences in the recognition of tax expenses for  
10       the financial statements compared to the tax return. Both the federal and state  
11       deferred tax balances reflect the netting of Deferred Tax Assets (Account 190)  
12       against Deferred Tax Liabilities (Accounts 281, 282, and 283), consistent with the  
13       presentation in the cost of capital calculation.

14  
15       Deferred taxes on line 119 include the outstanding tax liability balance to account  
16       for tax benefits previously flowed through to ratepayers stemming from the 1993  
17       enactment of ASC 740 as previously discussed. It is offset by the Regulatory Asset  
18       (Recoverable Income Taxes) shown on Schedule B4.2, line 67. This accounting  
19       and rate treatment were approved by the Commission in Case No. U-10083.

20  
21       Accumulated Deferred Investment Tax Credits on line 120, supported by Witness  
22       Wisniewski, are deferred tax credits generated and utilized by the Company with  
23       the tax benefits flowing back to customers on the same basis as customers pay for  
24       the assets that generated these tax credits.



Line  
No.

1 The Tax Reform Regulatory Liability on line 121 results from the Tax Cuts and  
2 Jobs Act of 2017, which among other things, lowered the corporate Federal tax rate  
3 from 35% to 21%. The reduction in the tax rate required that all existing deferred  
4 tax balances be re-measured using the 21% rate. The reduction in deferred taxes  
5 was recorded to a regulatory liability to be refunded, generally, over the life of the  
6 items causing the deferred tax, primarily plant. However, it also reflects accelerated  
7 amortization of the liability per the Commission's April 8, 2021, Order in Case No.  
8 U-20835. Witness Wisniewski explains the calculation of the regulatory liability  
9 and the Company's refund schedule.

10

11 **Q187. What is the regulatory liability for Investment Tax Credits on line 122?**

12 A187. Witness Guillaumin explains and supports the capital expenditures for a battery  
13 storage asset at the former Trenton Channel power plant location. As described by  
14 Witness Wisniewski, the Company expects to earn investment tax credits (ITCs)  
15 related to this new asset pursuant to the 2022 Inflation Reduction Act (IRA). As  
16 further explained by Witness Lepczyk, the Company plans to transfer the ITCs to  
17 a third party at a small discount in 2027. Because the Company plans to transfer  
18 these ITCs to a third party, they are not expected to be subject to the normalization  
19 requirements of the Internal Revenue Code, which require ITC benefits be returned  
20 to customers over a period no less than the book life of an asset. The Company will  
21 propose an amortization period to give customers the benefit from this transaction  
22 by crediting tax expense and lowering the Company's revenue requirement in a  
23 future rate case. Therefore, the Company plans to defer the investment tax credits  
24 to a regulatory liability, as calculated by Witness Wisniewski.

Line  
No.

1 **IRM Impacts**

2 **Q188. How does the Infrastructure Recovery Mechanism impact the projected**  
3 **financials?**

4 A188. An overview of the mechanism is provided by Company Witness Willis. The  
5 Commission Order in Case No. U-21297 approved an IRM for December 2023  
6 through December 2025. The Commission Order in Case No. U-21534 approved  
7 an extension through 2026. The IRM capital expenditures and plant balances, the  
8 related costs and revenues, and the related debt and equity are excluded from my  
9 projected financial statements. This exclusion ensures that the revenue requirement  
10 for the IRM is separate and distinct from the revenue requirement for base rates.  
11 Company Witness Willis describes and supports the Company's proposal to extend  
12 the IRM through 2028.

13

14 **Q189. Will the IRM expenditures be permanently excluded from base?**

15 A189. No. IRM investments will be transferred into the Company's overall rate base after  
16 the investments have been made and put into service. The Company will reflect  
17 this in the first general rate case after the investments have been reviewed through  
18 an IRM reconciliation proceeding consistent with the Commission's Order in Case  
19 No. U-21297. Until transferred to the Company's overall rate base rates, IRM  
20 investments will be recovered through the IRM surcharge. Once the Commission  
21 approves the transfer of assets from the IRM mechanism to the Company's overall  
22 rate base, these assets will be removed from the IRM surcharge.

23

24 **Q190. Is the Company proposing to reduce its future recovery by the amount of plant**  
25 **that is being retired in this IRM program?**

Line  
No.

1 A190. No. When plant is retired, the original recorded cost of the plant is both credited to  
2 the plant in service accounts and debited to accumulated depreciation reserve; thus,  
3 there is no change in the net plant balance related to the retirement. With no change  
4 in net plant, there is no adjustment to the largest portion of the return-on-investment  
5 portion of the revenue requirement calculation. As depreciation rates are  
6 periodically adjusted in subsequent depreciation cases, the impact of any abnormal  
7 retirements will be incorporated.

8

9 **Q191. What would be the impact on customers if the IRM is approved but the**  
10 **Company does not spend the full amount of projected capital expenditures?**

11 A191. As explained by Witness Willis, the Company will record a regulatory liability for  
12 any over-recovery related to the IRM. The recording of any Regulatory Liability  
13 will be reviewed through an IRM reconciliation proceeding, consistent with the  
14 Commission's Order in Case No. U-21297. The Company will use account 254,  
15 Other Regulatory Liabilities, for that purpose.

16

17 **Other Accounting Requests**

18 **Q192. What accounting treatment are you proposing for merchant fees?**

19 A192. As described by Witness Foley, the Company is requesting recovery of merchant  
20 fees related to the existing debit/credit card payment option for residential  
21 customers in O&M expense. In his testimony, he requests that if O&M recovery is  
22 not approved, that the Commission grant deferral treatment of the fees until the  
23 Company can implement a change to the card payment process. I am requesting  
24 the use of account 182.3, Other Regulatory Assets, to defer the fees for inclusion in  
25 a future rate case.

Line  
No.

1 **Q193. What accounting treatment are you supporting for outage credits?**

2 A193. As described by Witness Leslie, the Commission directed the Company to defer  
3 certain outage credits in account 182.3, Other Regulatory Assets. No deferred costs  
4 are reflected in the instant case. If the cost becomes material, the Company will  
5 defer the expense and request recovery in a future rate case.

6

7 **Q194. What accounting treatment are you proposing for O&M costs at MERC?**

8 A194. As supported by Witness Milo, the Company expects to incur operating costs at  
9 MERC through mid-2026 and his O&M forecast reflects a reduction based on that  
10 assumption. The Company proposes deferring as a regulatory liability any O&M  
11 costs at MERC that continue to be recovered in rates above the actual amount  
12 incurred, until rates are reset in a future rate case.

13

14 **Q195. What accounting treatment are you requesting for certain debt issuance costs?**

15 A195. As described by Witness Lepczyk, the Company is in the process of securing  
16 financing of up to \$7.2 billion from the United States Department of Energy under  
17 the Inflation Reduction Act, Section 1706. Normally, issuance costs associated  
18 with debt financing are recorded to FERC account 181, Unamortized Debt Expense,  
19 and amortized over the life of the debt. Issuance costs include, but are not limited  
20 to, commitment fees, due diligence and legal expenses.

21

22 The Company is requesting recovery of the issuance costs via a regulatory asset if  
23 the Company does not reach financial close on this loan. I am requesting the use  
24 of account 182.3, Other Regulatory Assets, to defer the costs for inclusion in a

Line  
No.

1 future rate case. (If the loan closes, the expenses will be recorded to FERC account  
2 181 and amortized per standard accounting practices.)

3

4 **Summary**

5 **Q196. Can you summarize what Commission approvals the Company is requesting?**

6 A196. In addition to the forecasted costs and revenues included herein, the Company is  
7 requesting a continuation of the previously approved deferral treatment for Pension  
8 expense, OPEB expense, incentive expense, LIA/RIA credits, Ludington overhaul  
9 expense, PERC projects, and certain Charging Forward/(TEP) programs. I am also  
10 requesting approval to use account 182.3 for deferred merchant fees, account 254  
11 to record any over recovery of MERC operating costs, and account 182.3 for  
12 issuance costs related to the 1706 loan program, if the financing does not close.

13

14 **Q197. Does this complete your direct testimony?**

15 A197. 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-21860

QUALIFICATIONS  
AND  
DIRECT TESTIMONY  
OF  
SHERRI L. WISNIEWSKI

**DTE ELECTRIC COMPANY**  
**QUALIFICATIONS AND DIRECT TESTIMONY OF SHERRI L. WISNIEWSKI**

Line  
No.

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

2    A1.   My name is Sherri L. Wisniewski (she/her/hers). My business address is: One  
3           Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate  
4           Services, LLC, a subsidiary of DTE Energy Company (DTE Energy).

5

6   **Q2.    On whose behalf are you testifying?**

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

8

9   **Q3.    What is your educational background?**

10   A3.   I earned a Bachelor of Business Administration from Western Michigan University  
11           in 1993 and a Master of Business Administration from The University of Michigan  
12           in 1998.

13

14   **Q4.    What is your work experience?**

15   A4.   I have been with DTE Energy in the Tax Department since 1996 and became  
16           Director of Tax Operations in July 2016 and I am currently responsible for tax  
17           accounting, tax forecasting, and regulatory tax.

18

19   **Q5.    Have you previously sponsored testimony before the Michigan Public Service**  
20           **Commission (MPSC or Commission)?**

21   A5.   I have sponsored testimony in the following cases:

22           U-18232       DTE Electric REP Amended Plan

23           U-18232       DTE Electric 2020 Amended REP Plan - March 2020

24           U-18255       DTE Electric Rate Case

25           U-18999       DTE Gas Rate Case

Line  
No.

|    |         |                                                                   |
|----|---------|-------------------------------------------------------------------|
| 1  | U-20029 | DTE Electric EWR 2017 Reconciliation                              |
| 2  | U-20051 | DTE Electric 2017 TRM Reconciliation                              |
| 3  | U-20105 | DTE Electric Credit A Rate Case                                   |
| 4  | U-20106 | DTE Gas Credit A Rate Case                                        |
| 5  | U-20162 | DTE Electric Rate Case                                            |
| 6  | U-20172 | DTE Electric REP 2017 Reconciliation                              |
| 7  | U-20298 | DTE Gas Calculation C                                             |
| 8  | U-20484 | DTE Electric REP 2018 Reconciliation                              |
| 9  | U-20561 | DTE Electric Rate Case                                            |
| 10 | U-20642 | DTE Gas Rate Case                                                 |
| 11 | U-20723 | DTE Electric REP 2019 Reconciliation                              |
| 12 | U-20835 | DTE Electric Company for Accounting Approval to Accelerate        |
| 13 |         | Amortization of the Tax Cuts and Job Act Regulatory Liability for |
| 14 |         | Non-Plant Related Accumulated Deferred Income Taxes               |
| 15 | U-20851 | DTE Electric 2020 Amended REP Plan                                |
| 16 | U-20940 | DTE Gas Rate Case                                                 |
| 17 | U-21010 | DTE Electric 2020 REP Reconciliation                              |
| 18 | U-20836 | DTE Electric Rate Case                                            |
| 19 | U-21285 | DTE Electric 2022 Amended REP Plan                                |
| 20 | U-21198 | DTE Electric 2021 REP Reconciliation                              |
| 21 | U-21291 | DTE Gas Rate Case                                                 |
| 22 | U-21297 | DTE Electric Rate Case                                            |
| 23 | U-21353 | DTE Electric REP 2022 Reconciliation                              |
| 24 | U-21361 | DTE Electric 2023 Amended REP Plan                                |
| 25 | U-21534 | DTE Electric Rate Case                                            |



Line  
No.

|   |         |                                      |
|---|---------|--------------------------------------|
| 1 | U-21550 | DTE Electric 2023 REP Reconciliation |
| 2 | U-21662 | DTE Electric Amended REP             |

Line  
No.

1 **Purpose of Testimony**

2 **Q6. What is the purpose of your testimony in this proceeding?**

3 A6. The purpose of my testimony is to discuss and support the reasonableness of DTE  
4 Electric's Federal Income Tax (FIT), Michigan Corporate Income Tax (MCIT),  
5 municipal (city) income tax, property tax and other general taxes for the 2023  
6 calendar year historical period and the twelve months ending December 31, 2026,  
7 projected test period.

8

9 **Q7. Are you sponsoring any exhibits in this proceeding?**

10 A7. Yes. I am supporting the following exhibits:

| 11 | <u>Exhibit</u> | <u>Schedule</u> | <u>Description</u>                      |
|----|----------------|-----------------|-----------------------------------------|
| 12 | A-3            | C7              | Historical General Taxes                |
| 13 | A-3            | C8              | Historical Federal Income Taxes         |
| 14 | A-3            | C9              | Historical State and Local Income Taxes |
| 15 | A-3            | C10             | Historical Other Taxes                  |
| 16 | A-13           | C7              | Projected General Taxes – Other         |
| 17 | A-13           | C7.1            | Projected General Taxes – Property      |
| 18 | A-13           | C8              | Projected Federal Income Tax            |
| 19 | A-13           | C8.1            | Projected TCJA Regulatory Liability     |
| 20 | A-13           | C9              | Projected State Income Tax              |
| 21 | A-13           | C10             | Projected Local Income Tax              |

22

23 **Q8. Were these exhibits prepared by you or under your direction?**

24 A8. Yes, they were.

Line  
No.

1 **Q9. What income tax rates are you assuming in this instant case?**

2 A9. For the projected test period reflected in this case, I am assuming a FIT rate of 21%  
3 and a MCIT rate of 5.88% (6% statutory rate at 98% apportionment) and municipal  
4 income tax of 0.33%. The municipal income tax rate represents a composite rate  
5 including all cities in which DTE Electric has a municipal income tax obligation.

6

7 **HISTORIC PERIOD**

8 **Q10. How was the 2023 historical period property tax expense derived for the rate**  
9 **case?**

10 A10. The 2023 historical period property tax expense in Exhibit A-3, Schedule C7, line  
11 1, column (c) and Exhibit A-13, Schedule C7, line 1, column (b) of \$291.4 million  
12 represents property tax expense on all DTE Electric property. Exhibit A-13,  
13 Schedule C7, line 1, shows the walk from the \$291.4 million in column (b) to  
14 \$267.8 million adjusted historical property tax expense in column (e). Adjusted  
15 historical property tax expense of \$267.8 million was applicable to property  
16 reflected in DTE Electric's general rate case filings (referred to hereafter as general  
17 rate case property), which includes \$0.9 million for Midwest Energy Resources  
18 Company (MERC) and excludes \$24.5 million applicable to Renewable Energy  
19 Plan (REP) property. Property tax *expense* refers to the amount of property taxes  
20 deducted for book purposes. Property tax *liability* refers to the amount of property  
21 taxes payable to local governments. Because the Company expenses its property  
22 tax liability over a two-year period,<sup>1</sup> one will see a difference annually between  
23 liability and expense.

---

<sup>1</sup> The Company expenses its property tax liability over a two-year period, with the liability of each year being expensed 39% the current year and 61% the subsequent year. This two-year allocation methodology has been used for many years and is based, generally, on the fiscal years of the various taxing jurisdictions to which property taxes are paid.

Line  
No.

1 **Q11. How was the 2023 historical period payroll tax expense derived?**

2 A11. The 2023 historical period payroll tax expense in Exhibit A-3, Schedule C7, line 2,  
3 column (c) of \$32.5 million consists of Social Security and Medicare taxes referred  
4 to collectively as “FICA” as well as federal and Michigan state unemployment  
5 taxes. These payroll taxes for the historic period are before rate case and  
6 normalization adjustments and are derived from the Company’s payroll system  
7 based on individual employees’ wages up to a maximum taxable limit times a  
8 prescribed rate.

9

10 **Q12. What are the Other General Taxes reflected on Exhibit A-3, Schedule C7?**

11 A12. In addition to payroll taxes of \$32.5 million, Public Utility Assessment fees of  
12 \$13.0 million and Use Tax and Other tax totaling \$(0.2) million are included in the  
13 Total Other General Taxes. Total Other General Taxes of \$45.4 million as shown  
14 on Exhibit A-3, Schedule C7 are for DTE Electric as a whole. Total 2023 historical  
15 other general tax expense after rate case and normalization adjustments is \$46.5  
16 million as shown on Exhibit A-3, Schedule C1.1, which is supported by Company  
17 Witness Uzenski.

18

19 **Q13. Is there anything unique or unusual regarding 2023 historical period income**  
20 **tax expense?**

21 A13. The 2023 historical period income tax expense, which includes FIT expense, MCIT  
22 expense, and municipal income tax expense, is calculated in a manner consistent  
23 with the methodology utilized in Case No. U-21534. Income tax expense includes  
24 both current income taxes (taxes payable currently) and deferred taxes (taxes

Line  
No.

1 payable in the future). Historical income tax expense amounts are shown on  
2 Exhibit A-3, Schedules C8 and C9.

3

4 The income tax expense amounts shown on Exhibit A-3, Schedules C8 and C9  
5 reflect income tax expense for DTE Electric as a whole. These income tax expense  
6 amounts are adjusted for rate case, normalization, and other adjustments in Exhibit  
7 A-3, Schedule C1.1, which is supported by Company Witness Uzenski. Total 2023  
8 historical year income tax expense after the adjustments is \$187.4 million.

9

10 **Q14. What do the balance sheet reclassifications on Witness Uzenski's Exhibit A-2,**  
11 **Schedule B6.1, column (e) represent?**

12 A14. In Exhibit A-2, Schedule B6.1, column (e), there are two items being reclassified  
13 to line 119, Accumulated Deferred Income Taxes.

14

15 The first item is a reclassification of the Accumulated Deferred Income Tax Asset  
16 on line 67 to Accumulated Deferred Income Taxes on line 119. This is done for  
17 proper balance sheet presentation and is consistent with prior rate case filings.

18

19 The second item is a reclassification of a portion of the Accumulated Deferred  
20 Investment Tax Credit on line 120 to Accumulated Deferred Income Taxes on line  
21 119. This represents Investment Tax Credits (ITCs) DTE Electric generated but  
22 had not yet utilized as of 12/31/2023. Because these ITCs will be utilized in a future  
23 year, a deferred tax asset was recorded and is included in line 119. Because DTE  
24 Electric has not recognized the cash benefit of the ITCs, the Accumulated Deferred

Line  
No.

1 Investment Tax Credit for these credits must be reclassified to eliminate any impact  
2 it would have on the cost of capital. This is consistent with prior rate case filings.

3

4 **FORECAST PERIOD**

5 **Q15. What subjects will your testimony and exhibits cover related to the twelve**  
6 **months ending December 31, 2026, projected test period?**

7 A15. I am supporting the FIT, MCIT, Municipal Income Tax, Property Tax and Other  
8 general taxes shown on Exhibit A-13, Schedules C7 through C10. These schedules,  
9 which are primarily based on forecasted amounts sponsored by other Company  
10 witnesses, are used to derive the various tax expense amounts for the projected test  
11 period.

12

13 **Q16. How are Michigan property taxes assessed?**

14 A16. Michigan property tax is imposed annually by local governments on the taxable  
15 value of all real and tangible personal property, including construction work in  
16 progress (CWIP), unless specifically exempted by law. The liability for any given  
17 year is based on the taxable value of property on December 31 of the previous year,  
18 which is referred to as the assessment date. For example, the 2023 liability is based  
19 on the taxable value of property on December 31, 2022.

20

21 The taxable value is calculated by multiplying the true cash value (see below) of  
22 the property by 50%. The liability is then derived by multiplying the taxable value  
23 by the millage rate (can also be referred to as a tax rate). Millage rates vary  
24 throughout the state and represent the aggregate levies for all taxing units (county,  
25 township, city, village, and school districts) within which the property is located.

Line  
No.

1 The liability is billed in two parts, with one bill generally received in December  
2 (referred to as the winter bill) and the other bill generally received in June (referred  
3 to as the summer bill). The billing dates and allocation of the liability between the  
4 billing dates is driven by the fiscal year of the taxing jurisdiction and, therefore,  
5 will vary by jurisdiction.

6

7 **Q17. In the calculation of the property tax liability, what is ‘true cash value’ and**  
8 **how is it calculated?**

9 A17. True cash value is meant to represent fair market value and is determined by local  
10 assessors who apply guidelines set forth by the State Tax Commission (STC),  
11 which supervises the valuation and assessment of property. To determine true cash  
12 value, assessors will utilize multiplier tables established by the STC. The tables  
13 are designed to mimic the expected life cycle of the property. STC multipliers will  
14 change over the life of the property to represent the change in value over time driven  
15 by factors such as typical usage patterns and obsolescence. An STC multiplier  
16 enables an assessor to determine true cash value by multiplying the appropriate  
17 STC multiplier by the historical cost of the property instead of performing a  
18 comprehensive market value analysis every year.

19

20 **Q18. When does the Company know its property tax liability for any given year?**

21 A18. The Company files property tax returns (referred to as renditions) in late February  
22 and early March to report property on hand as of the assessment date (December  
23 31). A separate rendition is filed with each assessor in each location where property  
24 is owned. The liability is still an estimate at that time and will continue to be

Line  
No.

1 updated as the Company receives assessments from local assessors in March and  
2 April and bills in June and December.

3

4 **Q19. How are the 2023 and 2024 property tax liabilities reflected in your exhibits?**

5 A19. Exhibit A-13, Schedule C7.1 shows the 2023 and 2024 property tax liabilities in  
6 column (c) on lines 3 and 4, respectively.

7

8 The 2023 tax liability<sup>2</sup> of \$278.3 million (line 3, column (c)) represents the actual  
9 property taxes assessed and paid on all general rate case property on hand as of  
10 December 31, 2022.

11

12 The 2024 tax liability of \$293.6 million (line 4, column (c)) represents the estimated  
13 property taxes that will be assessed and paid on all general rate case property on  
14 hand as of December 31, 2023, based primarily on assessments received from local  
15 assessors.

16

17 **Q20. What is the projected 2025 property tax liability?**

18 A20. Exhibit A-13, Schedule C7.1, shows the projected 2025 property tax liability of  
19 \$330.3 million on line 54, column (c).

20

21 **Q21. How was the projected 2025 property Tax liability on Exhibit A-13, Schedule**  
22 **C7.1, line 54 calculated?**

---

<sup>2</sup> Property tax *liability* refers to the amount of property taxes payable to local governments, whereas property tax *expense* refers to the amount of property taxes deducted for book purposes. The Company expenses its property tax liability over a two-year period, with the liability of each year being expensed 39% the current year and 61% the subsequent year. The 2023 Property tax expense as stated in the historical section of my testimony was \$291.4 million.



Line  
No.

1 A21. This represents the projected property taxes that will be assessed and paid on all  
2 general rate case property projected to be on hand as of December 31, 2024. This  
3 is based on the 2024 estimated tax liability of \$293.6 million (line 52, column (c))  
4 plus the increase in liability projected for 2025 of \$36.8 million (line 53, column  
5 (c)). The increase in liability projected for 2025 is calculated in column (c) on lines  
6 25 through 50. The taxable value of 2024 net additions is estimated to be \$700.2  
7 million (line 35, column (c)), driven primarily by 2024 capital additions less  
8 retirements and reductions and nontaxable expenditures. It also takes into  
9 consideration the change in CWIP and applies first year STC multipliers to both  
10 the net additions and the change in CWIP. Annual inflation of real property on  
11 hand as of December 31, 2023, is estimated to be an increase in taxable value of  
12 \$24.1 million (line 41, column (c)). Annual obsolescence of personal property on  
13 hand as of December 31, 2023, is estimated to be a reduction in taxable value of  
14 \$73.9 million (line 47, column (c)). The estimated composite millage rate of 56.5  
15 is then applied to the net increase in taxable value of \$650.4 million (line 48,  
16 column (c)).

17

18 Capital additions and retirements for all periods presented are supported by  
19 Company Witnesses sponsoring Schedules B5 through B5.10 of Exhibit A-12.

20

21 **Q22. What is the projected 2026 property tax liability?**

22 A22. Exhibit A-13, Schedule C7.1, shows the projected 2026 property tax liability of  
23 \$373.4 million on line 56, column (e).

Line  
No.

1 **Q23. How was the projected 2026 property tax liability on Exhibit A-13, Schedule**  
2 **C7.1, line 56 calculated?**

3 A23. This represents the projected property taxes that will be assessed and paid on all  
4 general rate case property projected to be on hand at December 31, 2025. This is  
5 based on the 2025 projected tax liability of \$330.3 million (line 54, column (e))  
6 plus the increase in liability projected for 2026 of \$43.1 million (line 55, column  
7 (e)). The increase in liability projected for 2026 is calculated in column (e) on lines  
8 25 through 50. The taxable value of 2025 net additions is estimated to be \$810.8  
9 million (line 35, column (e)), driven primarily by 2025 capital additions less  
10 retirements and reductions and nontaxable expenditures. It also takes into  
11 consideration the change in CWIP and applies first year STC multipliers to both  
12 the net additions and the change in CWIP. Annual inflation of real property on  
13 hand as of December 31, 2024, is estimated to be an increase in taxable value of  
14 \$24.8 million (line 41, column (e)). Annual obsolescence of personal property on  
15 hand as of December 31, 2024, is estimated to be a reduction in taxable value of  
16 \$72.7 million (line 47, column (e)). The estimated composite millage rate of 56.5  
17 is then applied to the net increase in taxable value of \$762.9 million (line 48,  
18 column (e)).

19

20 **Q24. What is the amount of property tax expense the Company is seeking recovery**  
21 **of, and how is it calculated?**

22 A24. The Company is seeking recovery of property tax expense of \$348.0 million for the  
23 projected test period (January 1, 2026, through December 31, 2026), which is  
24 included in Exhibit A-13, Schedule C1, line 6, column (e) supported by Witness  
25 Uzenski. Property tax *expense* refers to the amount of property taxes deducted for

Line  
No.

1 book purposes. Property tax *liability* refers to the amount of property taxes payable  
2 to local governments. The Company expenses its property tax liability over a two-  
3 year period, with the liability of each year being expensed 39% the current year and  
4 61% the subsequent year. This two-year allocation methodology has been used for  
5 many years and is based, generally, on the fiscal years of the various taxing  
6 jurisdictions to which property taxes are paid.

7

8 The 2026 calendar year property tax expense of \$348.0 million (Exhibit A-13,  
9 Schedule C7.1, line 19, column (e)) represents 61% of the 2025 projected property  
10 tax liability and 39% of the 2026 projected property tax liability. Projected test  
11 period property tax expense is equal to the 2026 calendar year property tax expense  
12 of \$348.0 million.

13

14 **Q25. Will 2026 capital expenditures have an impact on the projected 2026 property**  
15 **tax liability or the amount of property tax expense the Company is seeking**  
16 **recovery of in this filing?**

17 A25. No. The property tax liability for any given year is based on the taxable value of  
18 property on December 31 of the previous year. This means that the 2026 property  
19 tax liability is based on the taxable value of property on December 31, 2025.  
20 Therefore, 2026 capital expenditures have no impact on the 2026 property tax  
21 liability.

22

23 The projected test period property tax expense represents 61% of the 2025 projected  
24 property tax liability and 39% of the 2026 projected property tax liability. Because

Line  
No.

1 the 2026 capital expenditures have no impact on the 2026 property tax liability,  
2 they also have no impact on the projected test period property tax expense.

3

4 **Q26. What is the Other Tax Expense portion of DTE Electric's operating expense?**

5 A26. DTE Electric is seeking recovery of Other Tax Expense for the projected test period  
6 of \$52.1 million. Other Tax expense consists of payroll taxes (\$37.6 million),  
7 Public Utility Assessment fees (\$14.7 million), and miscellaneous other taxes  
8 (negative \$0.2 million) as shown on Exhibit A-13, Schedule C7 on lines 2 through  
9 5 in column (j).

10

11 **Q27. How did you forecast the Other Tax Expense?**

12 A27. Payroll taxes generally follow O&M expense. Because DTE Electric's O&M  
13 forecast is driven primarily by inflation increases, payroll taxes have been  
14 forecasted by first incrementing the historic period actual amounts by DTE  
15 Electric's assumed annual wage inflation rate. Exhibit A-13, Schedule C5.15,  
16 which is supported by Witness Uzenski, lists inflation rates for the interim forecast  
17 and projected test periods. Projection adjustments were then made for estimated  
18 savings related to the Voluntary Separation Incentive Program (VSIP), estimated  
19 savings related to the planned retirement of operations at MERC, and an increase  
20 related to O&M labor. Witness Leslie explains the VSIP program and the  
21 associated savings in further detail, Witness Milo explains the planned retirement  
22 of operations at MERC, and Witness Uzenski supports the increase in O&M labor.

23

24 **Q28. How much total income tax expense is the Company seeking recovery of?**

Line  
No.

1 A28. DTE Electric is seeking recovery of total income tax expense of \$170.9 million.  
2 This is comprised of FIT expense of \$109.4 million and MCIT and municipal  
3 income tax expense of \$61.5 million.  
4

5 **Q29. How was the FIT Expense portion of DTE Electric's operating expense**  
6 **developed?**

7 A29. Exhibit A-13, Schedule C8, line 52 shows DTE Electric's FIT expense for the  
8 projected test period is \$109.4 million. Exhibit A-13, Schedule C8, illustrates that  
9 FIT expense is comprised of current FIT expense (line 5) and deferred FIT expense  
10 (line 6). Current FIT expense is zero, which is calculated based on taxable loss as  
11 shown on line 8 through 44. Deferred FIT expense is shown on lines 45 thru 51  
12 and is based on book versus tax temporary differences and the net operating loss  
13 (NOL) carryforward (line 45), annual amortization of several Deferred Debits and  
14 Credits (FAS 109, Investment Tax Credit (ITC), and the Tax Cuts and Jobs Act  
15 (TCJA) (lines 46 - 48)), R&D Tax Credit carryforward (line 49) and utilization of  
16 tax credits generated in prior years (line 50).  
17

18 **Q30. Is the overall methodology for amortizing the TCJA regulatory liability, as**  
19 **reflected in Exhibit A-13, Schedule C8.1, consistent with the MPSC Order**  
20 **received in Case No. U-21534?**

21 A30. Yes. Amortization for the projected test period January 1, 2026 through December  
22 31, 2026, reduces tax expense by \$48.9 million as reflected in Exhibit A-13,  
23 Schedule C8, line 48.

Line  
No.

1   **Q31. How was the MCIT expense portion of DTE Electric's operating expense**  
2       **developed?**

3   A31. Line 14 of Exhibit A-13, Schedule C9, shows DTE Electric's MCIT expense for  
4       the projected test period is \$58.5 million. Exhibit A-13, Schedule C9, illustrates  
5       that MCIT expense is comprised of current MCIT and deferred MCIT. Current  
6       MCIT is zero due to a MCIT NOL carryforward being generated in the projected  
7       test period, as reflected on Exhibit A-13, Schedule C9, line 7. Deferred MCIT is  
8       based on book versus tax temporary differences, NOL carryforward, and the annual  
9       amortization of the MCIT Deferred Debit. The amortization of the MCIT Deferred  
10      Debit includes the impacts of the Michigan tax law changes of 2008 and 2012 and  
11      the re-measurement of MCIT deferred tax balances at December 31, 2018.

12

13   **Q32. How was the Municipal Income Tax Expense portion of DTE Electric's**  
14       **operating expense developed?**

15   A32. Line 11 of Exhibit A-13, Schedule C10, shows DTE Electric's municipal income  
16      tax for the projected test period is \$3.0 million. Exhibit A-13, Schedule C10,  
17      illustrates that municipal income tax expense is comprised of current and deferred  
18      municipal income tax expenses. Current municipal income tax is zero, as reflected  
19      on Exhibit A-13, Schedule C10, line 7. Deferred municipal income tax is based on  
20      book versus tax temporary differences, NOL carryforward, and the annual  
21      amortization of the City of Detroit Deferred Debit that arose from the City of  
22      Detroit tax law change of 2012.

23

24   **Q33. Can you explain the investment tax credit (ITC) related to battery storage?**

Line  
No.

1 A33. The 2022 Inflation Reduction Act (IRA) provides an ITC on qualifying battery  
2 storage facilities equal to 30% of eligible capital as well as an incremental 10%  
3 bonus for projects located within an “Energy Community”. The ITC is generated  
4 when the facility is placed in service, and the tax basis of the facility must be  
5 reduced by 50% of the ITC. ITCs are not refundable credits, and there are limits to  
6 how many can be utilized each year to reduce income taxes payable on a tax return.  
7 Battery storage ITCs not used in the year generated can be transferred to an  
8 unrelated party or carried forward and used in a future year.

9

10 **Q34. Does the Company expect to generate ITC on the Trenton Channel Battery**  
11 **Energy Storage System (BESS) during the projected test period?**

12 A34. Yes. Approximately 80% of the Trenton Channel BESS capital of \$409.6 million  
13 that is supported by Witness Guillaumin is anticipated to be eligible for the 30%  
14 ITC as well as an incremental 10% bonus ITC given the project’s location within  
15 an “Energy Community”. This results in an estimated ITC of \$131.1 million.

16

17 **Q35. How is the ITC on the Trenton Channel BESS reflected in this case?**

18 A35. As discussed by Witness Lepczyk, DTE Electric expects to transfer this ITC to a  
19 third party at a 5% discount. The ITC of \$131.1 million, the discount on the transfer  
20 of \$6.6 million, and the tax impact of the 50% tax basis reduction of \$17.0 nets to  
21 \$107.5 million that is being recorded as a regulatory liability. This regulatory  
22 liability will be amortized over a period that the Company will propose in a future  
23 rate case, as discussed by Witness Uzenski.

Line  
No.

1    **Q36. Does this complete your direct testimony?**

2    A36. 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-21860

QUALIFICATIONS  
  
AND  
  
DIRECT TESTIMONY  
  
OF  
  
AARON WILLIS

**DTE ELECTRIC COMPANY**  
**QUALIFICATIONS AND DIRECT TESTIMONY OF AARON WILLIS**

Line  
No.

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

2   A1.   My name is Aaron Willis (he/him/his). My business address is One Energy Plaza,  
3        Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC,  
4        a subsidiary of DTE Energy Company (DTE Energy), as Director, Regulatory  
5        Affairs.

6

7   **Q2.   On whose behalf are you testifying?**

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

9

10   **Q3.   What is your educational background?**

11   A3.   I received a Bachelor of Arts in Political Science from the University of Michigan,  
12        a Master's in Environmental Management from the Yale School of Forestry and  
13        Environmental Studies, and a Master's in Business Administration from the  
14        University of Maryland.

15

16   **Q4.   What is your work experience?**

17   A4.   In 2009, I was employed by the US Army Corps of Engineers, Institute for Water  
18        Resources as Social Scientist. In this role, I supported enforcement of the Clean  
19        Water Act and engagement with domestic and international partners on a variety of  
20        water resources issues. In 2015, I was employed by Booz Allen Hamilton in their  
21        energy practice, providing support to commercial and federal clients on a variety  
22        of energy matters including market strategies, project development, and new energy  
23        technologies.

Line  
No.

1 In 2017, I began my employment with DTE Energy as an Associate in Corporate  
2 Strategy. In this role, I supported key operational and strategic work across the  
3 Company. I was promoted to Senior Associate in 2019 and transitioned to  
4 Corporate Development, where I supported the Company's financial strategy. In  
5 2020, I accepted a position in Regulatory Affairs supporting the Company's state  
6 regulatory strategy and engagement with the Michigan Public Service Commission  
7 (MPSC or Commission), MPSC Staff, and Michigan energy stakeholders. In 2021,  
8 I became Manager, Regulatory Economics, with responsibilities including the  
9 management of regulatory activities relative to DTE Electric's rate strategy,  
10 pricing, and load research. In 2024, I was promoted to Director, Regulatory Affairs.

11

12 **Q5. What are your current duties and responsibilities?**

13 A5. My responsibilities include the management of regulatory activities relative to DTE  
14 Electric's rate strategy, regulatory mechanisms, pricing, revenue requirements, cost  
15 of service, and load research.

16

17 **Q6. Have you previously sponsored testimony before the Michigan Public Service**  
18 **Commission?**

19 A6. Yes. I have sponsored testimony in the following cases:

- 20 • U-21163 XL High Load Factor Rate
- 21 • U-20836 DTE Electric 2022 General Rate Case
- 22 • U-21193 DTE Electric 2022 Integrated Resource Plan
- 23 • U-21306 Rider No. 16 Transition
- 24 • U-21338 DTE Electric 2023 Securitization
- 25 • U-21297 DTE Electric 2023 General Rate Case

Line  
No.

- |   |           |                                                     |
|---|-----------|-----------------------------------------------------|
| 1 | • U-18091 | DTE Electric 2024 PURPA Case                        |
| 2 | • U-21534 | DTE Electric 2024 General Rate Case                 |
| 3 | • U-21909 | DTE Electric Performance Based Ratemaking Mechanism |

Line  
No.

1 **Purpose of Testimony**

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

3 A7. The purpose of my testimony is to address the topics as outlined below: Power  
4 Supply Costs, Residential Rate Design, Investment Recovery Mechanism (IRM)  
5 Scope and Surcharge Design, and Other Tariff Changes.

- 6 • **Power Supply Costs:** Support total power supply costs for the 12-month period  
7 ending December 31, 2026.

8 ○ Power supply costs include the projected base transmission expense,  
9 and base fuel and purchased power expense necessary for the sales  
10 forecast. While maintaining the current Power Supply Cost Recovery  
11 (PSCR) base of 31.26 mills per kilowatt hour at the generation level, I  
12 am proposing to update the loss factor to 7.76%, which will result in a  
13 PSCR base of 33.69 mills per kilowatt hour at the sales level to facilitate  
14 recovery of the projected costs. The method is consistent with prior  
15 Commission Orders, including in the Company's most recent general  
16 rate case, Case No. U-21534.

- 17 • **Rate Design:** Support the proposed rate design and language modifications for  
18 the Company's rate schedules:

19 ○ *Residential:* (1) The development of capacity and non-capacity charges for  
20 each residential rate schedule based on the cost of service supported by  
21 Company Witness Cejas Goyanes; (2) design of distribution rates for all  
22 residential secondary rate schedules; (3) Senior Credit Forecast.  
23 ○ *All customers:* (1) Proposed Rider 18 outflow credits, (2) nuclear surcharge  
24 designed to collect the Proposed Nuclear Surcharge Revenue.

Line  
No.

- 1       • **Infrastructure Recovery Mechanism (IRM):**
- 2               ○ *Overall:* Describe and support the key components of a proposal that the
- 3               Company is putting forth in this case related to the scope and duration
- 4               of its Distribution Infrastructure Recovery Mechanism.
- 5               ○ *Surcharge Design:* Support pricing of the 2027 - 2029 IRM surcharge
- 6               based on the revenue requirement calculated by Company Witness
- 7               Vangilder and allocated by Company Witness Cejas Goyanes.
- 8       • **Other Tariff Changes:**
- 9               ○ Contribution in Aid of Construction (CIAC) for residential electric
- 10              vehicle charging equipment.
- 11              ○ Voltage-level CIAC for new customer connections.

12

13 **Q8. Are you sponsoring any exhibits in this proceeding?**

14 A8. Yes. I am supporting the following exhibits:

| 15 | <u>Exhibit</u> | <u>Schedule</u> | <u>Description</u>                                    |
|----|----------------|-----------------|-------------------------------------------------------|
| 16 | A-13           | C4              | Calculation of Power Supply Expenses                  |
| 17 | A-13           | C4.1            | Five Year Average Loss Factor                         |
| 18 | A-16           | F2              | Summary Present and Proposed Revenues by Rate         |
| 19 |                |                 | Schedule – 12 months ending December 31, 2026         |
| 20 | A-16           | F3              | Present and Proposed Revenues by Rate Schedule – 12   |
| 21 |                |                 | months ending December 31, 2026                       |
| 22 | A-16           | F4              | Comparison of Present and Proposed Monthly Bills – 12 |
| 23 |                |                 | months ending December 31, 2026                       |
| 24 | A-16           | F6              | Calculation of Nuclear Surcharge                      |
| 25 | A-16           | F7              | Calculation of Rider 18 Outflow Credits               |

Line  
No.

|   |      |    |                                                     |
|---|------|----|-----------------------------------------------------|
| 1 | A-16 | F8 | Proposed Tariff Sheets                              |
| 2 | A-33 | X1 | Distribution IRM Proposed Investment and In-Service |
| 3 |      |    | Levels for 2027 - 2029                              |
| 4 | A-33 | X2 | Alternate 2027 - 2029 Distribution IRM Investment   |
| 5 |      |    | Levels                                              |
| 6 | A-33 | X7 | IRM Surcharge Design                                |

7

8 With respect to Exhibit A-16, Schedule F3, I am sponsoring pages 1-11, and  
9 Company Witnesses Turner and Hartley are sponsoring the remaining sheets  
10 contained in the exhibit. With respect to Exhibit A-16, Schedule F4, I am  
11 sponsoring pages 1-21, and Company Witness Turner is sponsoring the remaining  
12 sheets contained in the exhibit.

13

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

15 A9. Yes, they were.

16

17 **Power Supply Costs**

18 **Q10. Is DTE Electric proposing to reset the base power supply cost in this**  
19 **proceeding?**

20 A10. No. The base power supply cost reflected in Exhibit A-13, Schedule C4 consists of  
21 two components: 1) base cost at generation, and 2) a loss factor. The Company is  
22 proposing to update the loss factor in this case consistent with the method approved  
23 in Case No. U-21534 and prior cases – it is not proposing any change to the base  
24 power supply cost at generation originally established by the Commission in its  
25 Order in Case No. U-15244. Since it was established, the amount of 31.26 mills per

Line  
No.

1 kilowatt hour has been maintained in each of the Company's subsequent general  
2 rate cases (Case Nos. U-15768, U-17767, U-18014, U-18255, U-20162, U-20561,  
3 U-20836, U-21297, and U-21534). I have applied a loss factor of 7.76% to this  
4 amount, which results in a total PSCR base at the sales level of 33.69 mills per  
5 kilowatt hour as reflected in Exhibit A-13, Schedule C4. If approved, this amount  
6 will become the basis for recovery of the power supply costs with the same effective  
7 date as other rate changes approved in this proceeding. This amount will be  
8 reflected in the annual PSCR reconciliation, where the actual monthly PSCR  
9 revenue is a function of the approved base and the PSCR sales.

10

11 **Q11. How did you determine the loss factor of 7.76%?**

12 A11. The loss factor of 7.76% is the average difference between the annual system output  
13 and sales over the last five years ending with the historic test year, 2019 through  
14 2023, as shown in Exhibit A-13, Schedule C4.1. This is the method approved by  
15 the Commission in the Company's last rate case (Case No. U-21534).

16

17 **Q12. Have you projected any under or over recovery of power supply costs in this**  
18 **proceeding?**

19 A12. No. For the purpose of the instant case, the power supply costs equal the associated  
20 power supply revenues so there is no projected under or over recovery. Any actual  
21 under or over recovery of power supply costs are reconciled annually in the PSCR  
22 reconciliation filings. For purposes of this filing, Company Witnesses Turner,  
23 Hartley, and I have calculated present revenues using the existing base rates  
24 approved in the Commission's Order in Case No. U-21534 dated January 23, 2025



Line  
No.

1 (January 25 Order). We have used a zero PSCR factor to calculate revenues for the  
2 projected test period.

3

4 **Q13. What does Exhibit A-13, Schedule C4 show?**

5 A13. This schedule calculates the power supply expense for the projected test period. As  
6 stated earlier, the power supply costs and revenues are equivalent in the instant  
7 case, so the projected costs are a function of the proposed PSCR base shown on line  
8 3 and the projected power supply sales volumes on line 5. The transmission expense  
9 on line 7 is the amount included in the current base, as originally approved in Case  
10 No. U-15244. The power supply costs attributable to specific Rider 10, Rider 3  
11 (sales shown together on line 16) and D13 sales (sales shown on line 17), are not  
12 subject to the PSCR. Line 18 reflects total retail sales less Rider 10, Rider 3, and  
13 D13. The corresponding costs are shown on Lines 21 and 22 for Rider 10 and Rider  
14 3, and line 23 for D13. The total expense for the test period including transmission  
15 expense is \$1,353 million, as shown on line 31. Lines 35 through line 40 show the  
16 split of the total power supply expense between capacity and non-capacity, based  
17 on the PA 295 and PURPA related generation costs, capacity purchases and the net  
18 energy market sales supported by Company Witness Burgdorf.

19

20 **Rate Design**

21 **Q14. What does Exhibit A-16, Schedule F2 show?**

22 A14. This exhibit summarizes present and proposed revenues by rate schedule for the  
23 12-month period ending December 31, 2026. Present revenues are based on rates  
24 approved in the January 2025 Order. The exhibit provides a comparison of total  
25 present and proposed revenues on page 2, present and proposed power supply

Line  
No.

1 revenues on page 3, and present and proposed distribution revenues on page 4. The  
2 proposed power supply revenues on page 3 provides a separate breakout of capacity  
3 and non-capacity related power supply revenues.

4  
5 **Q15. What does Exhibit A-16, Schedule F3 show?**

6 A15. This exhibit shows the present and proposed rate design and corresponding revenue  
7 by rate schedule based on the billing determinants for the 12-month period ending  
8 December 31, 2026. The various billing components are listed in column (a), and  
9 the respective billing determinants, including units of measure, are listed in column  
10 (b). The billing determinants were developed based on historical data and  
11 relationships, as well as known and measurable changes, and are consistent with  
12 Company Witness Leuker's sales forecast. The existing rates, as approved in the  
13 January 2025 Order, are in column (c), and are used to calculate the present  
14 revenues in column (d). The rates proposed in this proceeding are in column (e),  
15 with the resulting revenues in column (f).

16  
17 The only exceptions to the layout described above for residential is for page 9 of  
18 Exhibit A-16, Schedule F3. Page 9 contains the rate design for a residential rate  
19 schedule the Commission first approved in the Company's general rate Case No.  
20 U-21297, Rate Schedule D1.13 Overnight Savers TOD. This rate schedule is  
21 designed to be revenue neutral to the Company's proposed Rate Schedule D1.11 in  
22 this case. For this page of Exhibit A-16 Schedule F3, column (d) is the proposed  
23 Rate Schedule D1.11 revenue. Column (e) contains the rates being proposed for  
24 Rate Schedule D1.13, with the resulting revenues in column (f).

Line  
No.

1 **Residential Rate Design**

2 **Q16. What residential rate schedules does the Company currently offer?**

3 A16. The Company offers several rate schedules for residential customers:

- 4 • Rate Schedule D1 is the Company's former standard residential service rate,  
5 which is now titled the Non-Transmitting Meter rate.
- 6 • Rate Schedule D1.11 is a product with rates that vary depending on season  
7 and time of day and is the Company's standard residential service rate.
- 8 • Rate Schedule D1.13 is a product with rates that vary depending on season  
9 and time of day and is available on an optional basis to residential  
10 customers.
- 11 • Rate Schedule D1.1 is a separately metered interruptible space conditioning  
12 service rate.
- 13 • Rate Schedule D1.2 is a product with rates that vary depending on season  
14 and time of day.
- 15 • Rate Schedule D1.7 is a separately metered rate available for supplemental  
16 geothermal electric service with rates dependent on season and time of day.
- 17 • Rate Schedule D1.8 is a dynamic peak pricing product that has three pricing  
18 periods based on time of day and that is periodically subject to critical peak  
19 pricing.
- 20 • Rate Schedule D1.9 is a separately metered product for supplemental  
21 service to charge electric vehicles.
- 22 • Rate Schedule D2 was available to customers for all electric service if all  
23 space heating was total electric and installed on a permanent basis. It is now  
24 available only to dwellings being served on the rate prior to December 17,  
25 2015.

Line  
No.

- 1 • Rate Schedule D5 is a separately metered interruptible electric water
- 2 heating product.

3

4 **Q17. What is the basis for the Company's proposed residential rate levels in this**  
5 **proceeding?**

6 A17. The basis for the proposed rate levels are the functionalized power supply and  
7 distribution deficiency/sufficiency amounts supported by Company Witness Cejas  
8 Goyanes as shown in his Exhibit A-16, Schedule F1.1, page 2 (for power supply)  
9 and his Exhibit A-16, Schedule F1.2, page 1 (for distribution). The proposed  
10 residential power supply and distribution charges were designed to meet the power  
11 supply and distribution deficiencies shown in these exhibits. The proposed  
12 residential power supply capacity and non-capacity rates were designed to recover  
13 the revenues pursuant to Company Witness Cejas Goyanes's Exhibit A-16,  
14 Schedule F1.5, which shows how much of the power supply revenue requirement  
15 for each rate class is capacity and non-capacity related.

16

17 Within the power supply cost of service, Company Witness Cejas Goyanes  
18 identifies three separate residential cost classes: "D1.11/Other", "D1.2", and "D2".  
19 All current residential rate schedules except D1.2 and D2 are included in  
20 D1.11/Other. For the D1.11/Other rate schedules, the power supply deficiency was  
21 allocated based on each rate schedule's percentage contribution to the present  
22 D1.11/Other power supply revenue. For those rate schedules with their own cost of  
23 service class (D1.2 and D2), the deficiency was directly allocated to the  
24 corresponding class. This is the same method used to develop the approved  
25 residential power supply rates in the Company's last rate case, Case No. U-21534.

Line  
No.

1   **Q18.   What is the Company’s proposed residential distribution rate design?**

2   A18.   In the Company’s rate case filed in 2014, Case No. U-17767, MPSC Staff  
3           recommended, and the Commission approved, variable distribution rates designed  
4           such that all customers in the Residential class would have the same rate, with the  
5           caveat that a cap was applied to limit the increase of any specific variable  
6           distribution rate. This method was again proposed and approved in each of the  
7           Company’s subsequent rate cases. The Company designed the variable distribution  
8           rates for each residential rate schedule in this case using this same premise. The  
9           Residential class rate schedules now all have the same distribution rate, and thus no  
10          cap on any individual Residential Secondary rate schedule’s distribution rate is  
11          applied in this case. The one exception is Rate Schedule D1.13, which has variable  
12          distribution rates designed consistent with the Orders in Case Nos. U-21297 and U-  
13          21534.

14

15   **Q19.   What does Exhibit A-16, Schedule F4 show?**

16   A19.   This exhibit shows a comparison of typical monthly bills by rate schedule based on  
17          present and proposed rates. For each rate schedule, the exhibit calculates the  
18          amount of a bill under existing rates and proposed rates across a broad range of  
19          energy consumption levels. The difference is representative of the impact of the  
20          proposed rate changes.

Line  
No.

1 Residential Senior Credit

2 **Q20. Is the Company forecasting an increase in the number of customers that will**  
3 **receive the residential senior citizen provision credit?**

4 A20. Yes. As described in my Exhibit A-16, Schedule F3, and using the same method as  
5 previously approved by the Commission, the Company is forecasting that 157,680  
6 total customers will receive the senior credit in the projected test year. The  
7 Company continues to see growth in customers utilizing the senior credit and the  
8 prior year trends suggest the increase will continue into the projected test year.  
9 Table 1 below shows the growth in senior credits applied over the last three years.

10

11 **Table 1 Historical Senior Credit Count**

12

| Month | 2022   | 2023    | 2024    |
|-------|--------|---------|---------|
| Jan   | 93,885 | 101,497 | 122,417 |
| Feb   | 94,040 | 103,588 | 123,860 |
| Mar   | 94,318 | 106,056 | 124,895 |
| Apr   | 94,153 | 108,087 | 125,818 |
| May   | 93,843 | 109,135 | 126,565 |
| Jun   | 93,896 | 110,001 | 127,202 |
| Jul   | 95,449 | 110,946 | 127,924 |
| Aug   | 95,795 | 112,062 | 128,620 |
| Sep   | 96,080 | 113,885 | 129,129 |
| Oct   | 96,558 | 117,250 | 129,547 |
| Nov   | 97,132 | 118,319 | 129,505 |
| Dec   | 98,281 | 119,732 | 129,797 |

13

14 **Q21. In the Company's most recent rate case, Case No. U-21534, what did the**  
15 **Commission order with respect to senior credits?**

16 A21. In its January 2025 Order, the Commission concurred with the Company's  
17 forecasting approach, concluding that the "Commission ultimately finds DTE

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1 Electric's reliance on actual enrollment numbers for the RSC to be more  
2 compelling"<sup>1</sup> and therefore approved the Company's filed number of 104,224. The  
3 Company's proposal in this case utilizes the same methodology.

4

5 **Nuclear Surcharge**

6 **Q22. What does Exhibit A-16, Schedule F6 show?**

7 A22. The Company's proposed nuclear surcharge is designed to collect the Proposed  
8 Nuclear Surcharge Revenue. Exhibit A-16, Schedule F6 shows the calculation of  
9 the Nuclear Surcharge, which recovers costs associated with nuclear site security  
10 & radiation protection, and the funding for nuclear decommissioning and low-level  
11 radioactive waste disposal. The proposed nuclear surcharge change is due to  
12 decreases in site security and radiation protection costs as supported by Company  
13 Witness Davis and higher forecasted jurisdictional sales.

14

15 **Rider 18 Outflow Credits**

16 **Q23. What does Exhibit A-16, Schedule F7, pages 1 through 2 show?**

17 A23. In Case No. U-20836, the Commission approved the Staff's method to calculate the  
18 outflow credit for customers taking service under Rider 18 (Distributed  
19 Generation). That same calculation method was utilized by the Company and once  
20 again approved in its last general rate case, Case No. U-21534. The outflow credit  
21 is based on power supply rates. Pages 1 and 2 of this exhibit show the calculation  
22 of the proposed outflow rates for each rate schedule by adding the non-capacity rate  
23 (column b) and capacity rate (column c). The outflow credits are calculated using

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<sup>1</sup> Case No. U-21534, January 23, 2025 Order, Pg 416.

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1 the same methodology proposed by Staff and approved by the Commission in Case  
2 Nos. U-20836, U-21297, and U-21534.

3

4 **Q24. Do the power supply outflow credits calculated on Exhibit A-16, Schedule F7**  
5 **and shown on Exhibit A-16, Schedule F8 (Sheet Nos. D-115.00 and 116.00),**  
6 **include the current PSCR factor?**

7 A24. No. Given the more frequent changes in the PSCR factor, for administrative  
8 convenience, the PSCR factor is not included. However, as stated in the currently  
9 approved Rate Book on Sheet No. D-114.00, when calculating the actual outflow  
10 credit applied to customer bills, the Company will add or subtract the current PSCR  
11 factor (which is shown on Sheet No. C-62.00) to the rates shown on Sheet Nos. D-  
12 115.00 and D-116.00. Rate Schedule D13 outflow credits would not be adjusted  
13 by PSCR as those customers are not subject to PSCR.

14

15 **Infrastructure Recovery Mechanism (IRM)**

16 **Q25. Can you please summarize the history of the Company's current Distribution**  
17 **IRM?**

18 A25. Yes. The Company's Distribution IRM was first authorized in the Commission's  
19 December 1, 2023 Order in Case No. U-21297 (December 2023 Order). In that  
20 Order, the Commission approved a roughly two-year IRM, starting on December  
21 1, 2023, and running through calendar year 2025. The Commission authorized IRM  
22 treatment for five capital programs totaling \$61.9 million of capital investment in  
23 2024 and \$290.1 million of capital investment in 2025. The Commission further  
24 authorized new annual IRM planning and reconciliation processes, including



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1 providing direction that a contested reconciliation proceeding should occur at the  
2 end of each IRM plan year.

3 In Case No. U-21534, the Company proposed a two-year extension of the IRM  
4 running through calendar year 2027, including total IRM capital investment of  
5 \$530.0 million in 2026 and \$720.0 million in 2027. The Company proposed that  
6 starting in 2026 the scope of the previously authorized “4.8 kV Circuit Automation”  
7 program be broadened to “Distribution Automation”, and that Pole and Pole Top  
8 Maintenance and Modernization (PTMM) be authorized for IRM treatment. The  
9 Company proposed specific capital investment amounts for each program.

10

11 In its January 2025 Order, the Commission approved a partial extension of the  
12 previously approved 2025 investment levels. Specifically, the Commission  
13 approved \$104 million of IRM capital investment in 2026 among Subtransmission  
14 Redesign and Rebuild, Breaker Replacement, URD Replacement, and Distribution  
15 Automation. The Commission declined to approve Conversions and PTMM as part  
16 of the 2026 IRM authorization. The Commission further approved a change from  
17 “4.8kV Circuit Automation” to a broader “Distribution Automation” program.

18

19 **Q26. What is the current status of the Company’s Distribution IRM?**

20 A26. At the time of filing the Company is currently executing against the 2025 IRM Plan  
21 that was posted on August 30, 2024 (amended on October 9, 2024) and discussed  
22 during a stakeholder session on October 30, 2024.

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1 Further, the Company filed the 2024 IRM Reconciliation on March 28, 2025, in  
2 Case No. U-21845.

3

4 **Q27. Is the Company proposing to roll in any previously authorized IRM capital to**  
5 **its overall rate base in this case?**

6 A27. No. As discussed previously, in its December 2023 Order the Commission provided  
7 direction that a contested reconciliation proceeding should occur after the  
8 conclusion of each IRM year. As such, DTE Electric will propose that IRM capital  
9 investments be transferred into the Company's overall rate base in its first general  
10 rate case after the conclusion of the reconciliation proceeding that addressed the  
11 capital investment. This approach avoids having the same capital investment being  
12 addressed in both a general rate case and a reconciliation proceeding at the same  
13 time.

14

15 As it relates to 2024 IRM capital investment, the Company filed a reconciliation on  
16 March 28, 2025, in Case No. U-21845. The Company will propose that the  
17 investments addressed in that proceeding be transferred into its overall rate base in  
18 the first general rate case filed following the conclusion of Case No. U-21845 and  
19 will reflect any findings of that case.

20

21 In the instant case, the Company is proposing recovery of investments made during  
22 the 2024 IRM Plan year, but which were beyond the authorized IRM levels – these  
23 investments are incremental to the approved IRM amounts and are not recovered  
24 in the IRM surcharge. These investments are supported by Company Witnesses

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1 Stowe, Robinson, and Rademacher, and Exhibit A-12, Schedule B.5.4.8 provides  
2 additional detail on the inclusions in the instant case.

3

4 **Q28. What is the Company proposing in this case related to its Distribution IRM?**

5 A28. The Company is making proposals for two distinct periods.

- 6 • A primary and alternative proposal for 2027 – 2029, beyond the projected  
7 test year in the instant case; and  
8 • An alternative option for 2026, the projected test year in this case – this  
9 option expands the 2026 IRM to include the full amount sought for recovery  
10 in the instant case should the Commission find it appropriate to approve the  
11 capital in the IRM instead of base rates.

12 In addition, the Company is proposing an enhanced stakeholder engagement  
13 process.

14

15 **Q29. What are the customer benefits associated with the Distribution IRM?**

16 A29. The Company's original IRM proposal in Case No. U-21297 described four key  
17 benefits of the IRM, which were reiterated in Case No. U-21534. They are (1)  
18 increased accountability, (2) review and input, (3) increased transparency, and (4)  
19 investment certainty. These benefits remain true today, and as the Company looks  
20 ahead to future investments to support the goal of improved reliability for its  
21 customers, the IRM remains a key mechanism to achieve those goals.

- 22 • *Increased accountability.* The Company's filing in Case No. U-21845  
23 provides actual project level cost and unit cost for the completed 2024 IRM  
24 year and compares this information to what was projected in the 2024 IRM  
25 Plan filing

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- 1           • *Review and input.* The Company has completed two cycles of IRM Plan
- 2           development and engagement.
- 3                 ○ The 2024 IRM Plan was filed on February 7, 2024, in Case No. U-
- 4                 21297 and the Company hosted a Stakeholder Forum on February
- 5                 23, 2024 to review the proposed plan and receive stakeholder
- 6                 feedback. All parties to Case No. U-21297 were invited to the
- 7                 forum.
- 8                 ○ The 2025 IRM Plan was initially filed on August 30, 2024, in Case
- 9                 No. U-21297 and the Company hosted a Stakeholder Forum on
- 10                October 30, 2024, to review the proposed plan and receive
- 11                stakeholder feedback. The combined service list from Case Nos. U-
- 12                21297 and U-21534 were invited to the forum.
- 13           • *Increased transparency.* The IRM Plan provides project level metrics which
- 14           are more detailed and more specific than in rate cases, and the
- 15           Reconciliation requires the Company to demonstrate any variance between
- 16           the Plan and actual investments
- 17           • *Certainty of investment.* The IRM requires investments be made in specific
- 18           programs and at specified amounts. If the authorized, program-specific
- 19           investment levels are not achieved, customers are refunded the difference.

20

21   **Q30. How does the Company recover capital investments absent the IRM?**

22   A30. All else equal, investments not proposed for recovery in the IRM would be

23   proposed for recovery in base rates as the Company's overall investment plans are

24   not contingent on IRM treatment – the IRM is one form of cost recovery that brings

25   with it an increased level of transparency and accountability as described above.

Line  
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1   **Q31. Do other jurisdictions utilize capital recovery mechanisms outside of rate**  
2       **cases?**

3   A31. Yes. As of 2022, 21 states plus the District of Columbia had approved an electric  
4       distribution capital adjustment clause or rider. While differing in the specific detail,  
5       approval mechanisms, size, and capital supported relative to the Company's IRM,  
6       in the aggregate they demonstrate broad support for the recovery of distribution  
7       investments outside of traditional rate case approaches.

8

9   **2027 – 2029 IRM Primary Proposal and Alternative**

10   **Q32. Can you please describe the Company's primary IRM proposal for 2027 –**  
11       **2029?**

12   A32. The Company is proposing to extend the IRM through calendar year 2029,  
13       including new investment authorizations for 2027, 2028, and 2029 as described  
14       below. This includes continued authorization for existing programs, as well as new  
15       authorization for the Pole and Pole Top Maintenance and Modernization (PTMM)  
16       and System Cable programs. As can be seen in Table 2 below, most of the  
17       Company's proposed IRM authorization increases are focused on PTMM and  
18       Distribution Automation. This is consistent with the Company's long-term  
19       investment plans to meet its reliability objectives, as discussed by Company  
20       Witnesses Stowe, Robinson, and Rademacher.

21

22       The Company is proposing a level of capital investment and maximum in-servicing  
23       amount for each program and year. The full detail of the Company's proposed  
24       investment and in-service levels is captured in Exhibit A-33, Schedule X1, and is  
25       summarized in Table 2. The specific programs and investment amounts are

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1 supported by their respective Company Witnesses, including Witness Stowe for  
2 Subtransmission, Witness Robinson for Breaker, URD, System Cable, and PTMM,  
3 and Witness Rademacher for Automation.

4

5

**Table 2 – Proposed IRM Investment Levels (\$M)**

|                                      | Previously Approved |              |              | Proposed     |              |                |
|--------------------------------------|---------------------|--------------|--------------|--------------|--------------|----------------|
| Capital Program                      | 2024                | 2025         | 2026         | 2027         | 2028         | 2029           |
| Conversions                          | 1.6                 | 185.8        | 0            | 0            | 0            | 0              |
| Subtransmission Redesign & Rebuild   | 5.5                 | 53.8         | 53.8         | 105          | 115          | 120            |
| Breaker Replacement                  | 13.7                | 12.6         | 12.6         | 15           | 22           | 26             |
| URD Replacement                      | 14.6                | 13.5         | 13.5         | 15           | 20           | 26             |
| System Cable                         | n/a                 | n/a          | n/a          | 25           | 30           | 34             |
| Distribution Automation <sup>2</sup> | 26.4                | 24.4         | 24.4         | 165          | 250          | 320            |
| PTMM                                 | n/a                 | n/a          | n/a          | 263.4        | 376.8        | 482.6          |
| <b>Total</b>                         | <b>61.9</b>         | <b>290.1</b> | <b>104.3</b> | <b>588.4</b> | <b>813.8</b> | <b>1,008.6</b> |

6

7 The Company is not proposing any modifications to the annual reconciliation  
8 process of the Distribution IRM approved by the Commission through its  
9 December 2023 Order and affirmed in its January 2025 Order. However, the  
10 Company is proposing an update to the revenue requirement calculation to better  
11 align the IRM with base ratemaking - Company Witness Vangilder further  
12 addresses this change. The Company is not proposing any other modifications to  
13 the underlying mechanics relative to the December 2023 and January 2025 Orders.

<sup>2</sup> Authorized as “4.8 kV Circuit Automation” for IRM Years 2024 and 2025.

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1 In their testimony, Company Witness Vangilder supports the revenue requirement  
2 associated with the Company's proposed IRM investments and Company Witness  
3 Cejas Goyanes supports the cost-of-service treatment. I support the rate design of  
4 the surcharges to collect the allocated revenue requirement.

5  
6 **Q33. Why is a three-year IRM authorization appropriate?**

7 A33. The customer benefits associated with the IRM, the conclusion of the Distribution  
8 Audit in Case No. U-21305, and the Company's enhanced stakeholder engagement  
9 make this an appropriate time for the Commission to authorize an IRM for three  
10 years.

11  
12 In its January 2025 Order, the Commission noted that a one-year extension was  
13 appropriate to "achieves[sic] a reasonable balance between avoiding a disruptive  
14 lapse in the IRM and the Staff's argument that the findings of the distribution audit  
15 in Case No. U-21305 and the PBR docket in Case No. U-21400 should be  
16 incorporated into the next IRM."<sup>3</sup> As discussed in detail by Company Witness Chiu,  
17 the Company's distribution plans in this case (including its proposed IRM) are  
18 reflective of the findings of the Distribution Audit conducted in Case No. U-21305.  
19 In addition, PBR is being concurrently addressed in Case No. U-21400 with the  
20 Company's proposal filed on April 15, 2025, in Case No. U-21909 – as such the  
21 Company is not including a PBR proposal in the instant case.

22  
23 Beyond PBR and the Distribution Audit, the Company is continuing to focus on  
24 environmental justice in its investment planning and believes that its proposed

---

<sup>3</sup> January 2025 Order, Pp 301-302.

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1 investments for the IRM are well supported by environmental justice (EJ) and the  
2 EJ adjustments to investment prioritization as described by Company Witness  
3 Kryscynski.

4  
5 **Q34. What is the Company's proposed enhanced IRM stakeholder process?**

6 A34. The Company recognizes the value of stakeholder engagement and planning  
7 transparency in the IRM planning process, particularly as it grows to the level and  
8 scope proposed by the Company. As such, the Company believes it is important to  
9 provide additional opportunities for input in the IRM process and is proposing two  
10 such updates to the IRM process.

11 • *IRM Technical Conference.* The 2027 – 2029 expansion of the IRM  
12 provides an opportunity to enhance the Company's planning approaches  
13 and consideration of stakeholder feedback. The intent of the Technical  
14 Conference would be to describe the Company's existing approaches to  
15 selection and prioritization, as well as solicit and discuss additional  
16 stakeholder feedback well before the expanded IRM Plan Years. The  
17 Company intends to host this discussion in October 2025 in conjunction  
18 with the 2026 IRM Plan Stakeholder session that is part of the current IRM  
19 process.

20 • *Initial Stakeholder Meetings.* The approved IRM process calls for the filing  
21 of the IRM Plan at least four months before the year begins and a  
22 stakeholder meeting at least two months before the year begins. Beginning  
23 with the 2027 Plan, the Company proposes to add a stakeholder meeting to  
24 be held before the Plan is filed. This discussion, held by the end of June



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1 each year, will allow an opportunity for stakeholder input while the Plan is  
2 in development.

3

4 **Q35. Why is the Company including PTMM in its IRM proposal?**

5 A35. As described by Company Witness Robinson, PTMM is a key program supporting  
6 reliability improvements on the system and which will grow over the next several  
7 years. In addition, as described by Company Witnesses Chiu and Robinson, the  
8 distribution audit supported the role of the PTMM program in achieving improved  
9 reliability outcomes. In addition, as described by Company Witness Kryscynski,  
10 the Company utilizes environmental justice as an input into prioritizing these  
11 investments. As such, it is appropriate to include this important and growing  
12 program in the IRM.

13

14 **Q36. Why is the Company additionally including System Cable in its IRM**  
15 **proposal?**

16 A36. As described by Company Witness Robinson, System Cable and URD make up the  
17 Underground System Investment in System Equipment Replacement program. The  
18 Commission has previously approved URD within the IRM and it is appropriate to  
19 support the full underground portion of the System Equipment Replacement  
20 program in the IRM.

21

22 In addition, and as expanded upon by Company Witness Robinson, the January  
23 2025 Order supported the Company's investments in System Cable and the benefits  
24 those investments have on customer reliability.

Line  
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1   **Q37. Is the Company proposing an alternative option for the 2027 – 2029 IRM?**

2   A37. Yes. The Company believes that the proposal discussed above is reasonable and  
3       would bring with it benefits to transparency, customer protections, and long-term  
4       stability and certainty in planning. At the same time, the Company recognizes that  
5       the Commission and/or other stakeholders, while acknowledging the benefits of the  
6       IRM, may nonetheless desire a slower ramp of IRM investments to ensure IRM-  
7       related processes (e.g., reconciliation) are working as intended. As such, the  
8       Company is including an alternative 2027 – 2029 IRM proposal with a more  
9       gradual increase in IRM treatment for key program investment levels and overall.  
10      The Company’s alternative 2027 – 2029 IRM proposal does not change what the  
11      Company believes are appropriate investment levels for the programs – it only  
12      reduces the portion of the investments which would be recovered in the IRM. The  
13      alternative maintains the same spending levels in URD, Breakers, and System  
14      Cable compared to the primary proposal discussed above but reflects 50% of the  
15      spending levels proposed above for Distribution Automation, PTMM, and  
16      Subtransmission. These investments are expanded upon in the Company’s Exhibit  
17      A-33, Schedules X2 and X5, and are summarized in Table 3 below.

Line  
No.

1 **Table 3 – Proposed IRM Investment Levels for Alternative Option (\$M)**

2

|                                             | Previously Approved |              |              | Alternative Option |              |              |
|---------------------------------------------|---------------------|--------------|--------------|--------------------|--------------|--------------|
| Capital Program                             | 2024                | 2025         | 2026         | 2027               | 2028         | 2029         |
| Conversions                                 | 1.6                 | 185.8        | 0            | 0                  | 0            | 0            |
| Subtransmission Redesign & Rebuild          | 5.5                 | 53.8         | 53.8         | 52.5               | 57.5         | 60.0         |
| Breaker Replacement                         | 13.7                | 12.6         | 12.6         | 15.0               | 22.0         | 26.0         |
| URD Replacement                             | 14.6                | 13.5         | 13.5         | 15.0               | 20.0         | 26.0         |
| System Cable                                | n/a                 | n/a          | n/a          | 25.0               | 30.0         | 34.0         |
| Distribution Automation <sup>4</sup>        | 26.4                | 24.4         | 24.4         | 82.5               | 125.0        | 160.0        |
| Pole & Pole Top Maintenance & Modernization | n/a                 | n/a          | n/a          | 131.7              | 188.4        | 241.3        |
| <b>Total</b>                                | <b>61.9</b>         | <b>290.1</b> | <b>104.3</b> | <b>321.7</b>       | <b>442.9</b> | <b>547.3</b> |

3

4 **Q38. Do you believe the slower ramp rate for the 2027-2029 IRM is necessary?**

5 A38. No. The Company's IRM reconciliation filed on March 28, 2025, in Case No. U-  
6 21845 provides evidence that the process developed by the Commission and  
7 originally adopted in Case No. U-21297 is functioning as intended and providing  
8 the expected customer benefits. The enhanced stakeholder process proposed by the  
9 Company in this case provides further opportunity for stakeholder engagement as  
10 the IRM moves into future years.

<sup>4</sup> Authorized as "4.8 kV Circuit Automation" for IRM Years 2024 and 2025.

Line  
No.

1     **2026 IRM Option**

2     **Q39. What is the Company proposing for 2026?**

3     A39. As described by Company Witness Chiu and other witnesses, and reflected in the  
4           Company's exhibits, the Company is maintaining focus on investments in key  
5           strategic distribution programs in 2026. The Company's primary proposal for 2026,  
6           and reflected in its capital exhibits, is to execute on the previously approved IRM  
7           and recover all other proposed investments in base rates.

8  
9           However, while the Company is prepared to execute on that plan, it appreciates that  
10          the IRM includes accountability considerations that the Commission may find  
11          appropriate to mitigate any execution risk it sees. As such, we believe an alternative  
12          approach is to increase 2026 IRM authorization to mitigate any execution concerns  
13          while also allowing the Company to invest at required levels.

14  
15          The alternative 2026 IRM would include the full capital amounts for the below  
16          programs, including the addition of PTMM to the IRM and expanded IRM support  
17          for Subtransmission and Distribution Automation. In total, the 2026 IRM would  
18          provide for the investment levels reflected in Table 4 below and with in-servicing  
19          assumptions consistent with current approvals.

Line  
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1

**Table 4 – Alternative 2026 Proposed IRM Investment Levels (\$M)**

| Capital Program                             | 2026<br>Approved | 2026<br>Alternative |
|---------------------------------------------|------------------|---------------------|
| Subtransmission Redesign & Rebuild          | 53.8             | 100.0               |
| Breaker Replacement                         | 12.6             | 12.6                |
| URD Replacement                             | 13.5             | 13.5                |
| Distribution Automation <sup>5</sup>        | 24.4             | 140.0               |
| Pole & Pole Top Maintenance & Modernization | n/a              | 200.0               |
| <b>Total</b>                                | <b>104.3</b>     | <b>466.1</b>        |

2

3 **Q40. How are approved IRM investments recovered in the absence of an extension**  
4 **of the program or the roll in of assets to rate base in a general rate case?**

5 A40. Capital investments generate a revenue requirement, which in the case of IRM  
6 investment is initially recovered through the IRM surcharge and eventually through  
7 base rates following the reconciliation proceeding. As such, an IRM surcharge  
8 remains applicable to recover investment costs until such time that the recovery is  
9 moved to base rates, even if new IRM investments are not approved or executed  
10 during that time. More specifically, the IRM surcharge should reflect the actual  
11 approved revenue requirement of the underlying investments which have not yet  
12 been moved into base rates. This includes previously in-serviced amounts, and any  
13 future in-servicing associated with approved capital investment.

---

<sup>5</sup> Authorized as “4.8 kV Circuit Automation” for IRM Years 2024 and 2025.

Line  
No.

1 IRM Surcharge Design

2 **Q41. What is the basis for your proposed surcharge design?**

3 A41. The proposed IRM includes exclusively distribution investments, and therefore it  
4 is most appropriate to design the surcharge consistent with distribution rate design  
5 generally. Company Witness Cejas Goyanes provided IRM revenue requirements  
6 allocated among the existing distribution cost of service classes, which include  
7 Residential Secondary, Commercial Secondary, Primary, and Subtransmission, and  
8 four classes related to lighting. Consistent with the IRM surcharge rate design  
9 approved in Case No. U-21534 and the testimony of Company Witnesses Vangilder  
10 and Cejas Goyanes, I designed surcharges for each distribution cost of service class  
11 and rate schedule (as applicable), as reflected in Exhibit A-33, Schedule X7. Plan  
12 Years 2027, 2028, and 2029 reflect the primary IRM proposal and associated  
13 revenue requirement as described above.

14

15 Other Tariff Changes

16 **Q42. What does Exhibit A-16, Schedule F8 show?**

17 A42. This exhibit contains the proposed residential rate and tariff sheet changes which  
18 result from the pricing changes and other proposals described above and additional  
19 proposals described below.

20

21 **Q43. Are you sponsoring any changes to the tariff sheets?**

22 A43. Yes.

Line  
No.

1   **Q44. Are you proposing any updates to the Contribution in Aid of Construction**  
2       **(CIAC) standard allowance table?**

3   A44. Yes. I am proposing updates to the CIAC standard allowance table for customers  
4       with new or expanded load greater than 1000 kW consistent with the method  
5       approved in Case No. U-21534.

6  
7   **Q45. Is the Company proposing any tariff changes relative to CIAC for electric**  
8       **vehicles?**

9   A45. Yes. In its January 2025 Order, the Commission directed the Company to modify  
10       tariff sheet no. C-27.00, using Consumers Energy sheet D-14.00 as guidance, to  
11       establish a limited waiver for CIAC which may arise from residential EV charger  
12       installation. As further directed by the Commission, the Company held a discussion  
13       with Staff and interested parties March 19, 2025. The Company proposes to add  
14       Section C6.1 (16) with the following language, which includes input from the  
15       stakeholder discussion:

16           *“Residential minimum service is 10 kW of connected load. Service for*  
17           *residential electric vehicle charging is not considered in the minimum service.*  
18           *Electric vehicle charging equipment exceeding 9.6 kW of demand at the meter,*  
19           *or total connected load exceeding 10 kW (excluding electric vehicle charging*  
20           *equipment), may be subject to additional charges in accordance with the*  
21           *Section C6.”*

22

23   **Q46. Are you proposing any other changes to the Company’s rate book?**

24   A46. Yes. I am sponsoring the following changes to the rate book, reflected in Exhibit  
25       A-16, Schedule F8.

Line  
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- 1 • CIAC update regarding impacts of service voltage on customer cost. This is
- 2 further discussed by Company Witness Stowe and is included as a proposed
- 3 C6.1 (17) of the rate book.
- 4 • The elimination of Rate Schedule D1.6. In its January 2025 Order, the
- 5 Commission approved the Company's request to retire Rate Schedule D1.6 and
- 6 to transition customers to Rate Schedule D1.11 by the end of the projected test
- 7 year in that case. Accordingly, in this case the Company is proposing to
- 8 eliminate Rate Schedule D1.6.
- 9 • Updating the Low Income Assistance (LIA) Credit language to specify it is a
- 10 per customer per month credit. This change clarifies the credit can be obtained
- 11 once per customer and is consistent with language used for other approved
- 12 residential credits (the Residential Income Assistance (RIA) Provision and
- 13 Residential Senior Citizen Provision). This change maintains consistency with
- 14 other language in the same sections (e.g, Sheet No. D-7.00) which characterize
- 15 the LIA credit as limited to 32,000 customers, and not meters.

16

17 **Q47. Does this conclude your testimony?**

18 A47. Yes.



**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-21860

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

RODRIGO CEJAS GOYANES

**DTE ELECTRIC COMPANY**  
**QUALIFICATIONS AND DIRECT TESTIMONY OF RODRIGO CEJAS GOYANES**

Line  
No.

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

2    A1.    My name is Rodrigo Cejas Goyanes (he/him/his). My business address is One  
3           Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate  
4           Services, LLC, a subsidiary of DTE Energy Company (DTE Energy), as Consultant  
5           – Regulatory Economics in the Revenue Requirements Department of Regulatory  
6           Affairs.

7  
8    **Q2.    On whose behalf are you testifying?**

9    A2.    I am testifying on behalf of DTE Electric Company (DTE Electric or Company).  
10

11   **Q3.    What is your educational background?**

12   A3.    I graduated from the University of Buenos Aires, City of Buenos Aires, Argentina,  
13           with a degree as a Certified Public Accountant in 1992. Concurrently, I graduated  
14           with a Specialization in Taxes. In 2003, I received a Master of Business  
15           Administration with a Major in Finance and Management and Strategy from the  
16           Kellogg School of Management, Northwestern University, Evanston, Illinois.

17  
18   **Q4.    Have you completed any seminars or other training courses?**

19   A4.    Yes, I have. I attended training organized by Electric Utility Consultants, Inc,  
20           (EUCI) on utility cost of service and ratemaking, and demand response. Also, I  
21           specifically completed the Advanced Cost Allocation and Rate Design course,  
22           focused on cost allocation, conducted by the Institute of Public Utilities at Michigan  
23           State University.

Line  
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1   **Q5.   What is your work experience?**

2   A5.   I held a position as manager in the Tax Department of PwC (formerly known as  
3       PricewaterhouseCoopers) from 1993 to 1998, advising businesses and individuals  
4       on tax planning, and multiple tax matters in merger and acquisition transactions.  
5       Afterwards, I owned and managed an independent accounting service practice,  
6       advising individual clients on tax matters until 2001. I performed both roles in  
7       Buenos Aires, Argentina.

8

9       In 2003, I joined DTE Electric as a financial consultant in the graduate development  
10      program where I was responsible for evaluating and reporting electric sales and  
11      economic forecasts, implementing the systematization of tax credit requests, and  
12      assisting in the completion of bond offerings led by the treasury department.

13

14      In 2007, I accepted an internal position as Associate, and later Senior Associate, in  
15      DTE Energy's Power and Industrial group. In this role, I evaluated multiple  
16      investment opportunities in the competitive energy landscape from a financial and  
17      strategic point of view and performed budgeting and financial performance  
18      evaluation of the landfill gas and coal mine methane business units.

19

20      In 2014, I accepted a Senior Associate position on the Strategy team in DTE  
21      Electric, focusing primarily on supporting the Business Planning and Development  
22      department's testimonies in the Company's general rate cases before the Michigan  
23      Public Service Commission (MPSC or Commission). In addition, I performed long  
24      term financial feasibility of some of the Company's generation units under potential

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1 plant retirement scenarios, and concurrently, compiled and presented internal  
2 metrics and scorecard reports to senior management.

3

4 In 2018, I accepted a position as Strategy and Project Specialist in the Demand  
5 Response (DR) and Energy Waste Reduction (EWR) Strategy group. With respect  
6 to DR, my responsibility centered around the strategic and financial evaluation and  
7 planning of DR programs and pilots within DTE Electric. Specifically, my role  
8 focused on evaluating the market and regulatory framework for DR and providing  
9 development, operational and financial analysis support of the existing demand  
10 response programs and future pilots. I sponsored the Company's DR programs and  
11 pilots in various regulatory proceedings such as DTE Electric's rate cases and DR  
12 reconciliation cases.

13

14 From 2021 to August 2024, I joined the Integrated Resource Planning (IRP) group  
15 as Supervisor. I led the financial analysis and evaluation of potential resources for  
16 further consideration in IRP analyses. In this capacity as subject matter expert, I  
17 sponsored testimony in the DTE Electric's U-21193 IRP Case, in which I supported  
18 and validated IRP inputs and assumptions in the modeling and proceeding stages.  
19 During the respective regulatory proceedings, I also organized and led workshops  
20 for various stakeholders.

21

22 **Q6. What are your current duties and responsibilities?**

23 A6. As a Consultant - Regulatory Economics in DTE Energy's Regulatory Affairs  
24 Organization, I am responsible for the preparation and determination of revenue

Line  
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1 requirement, cost of service and rate design studies for regulatory filings, along  
2 with the complementary regulatory analysis and research.

3

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

6 A7. Yes. I have sponsored testimony and exhibits before the MPSC in the following  
7 DTE Electric cases:

8 U-20521 DTE Electric 2017-2018 Demand Response Reconciliation Case

9 U-20561 DTE Electric 2019 General Rate Case

10 U-20793 DTE Electric 2019 Demand Response Reconciliation Case

11 U-21044 DTE Electric 2020 Demand Response Reconciliation Case

12 U-21193 DTE Electric 2022 Integrated Resource Plan

13

14 **Purpose of Testimony**

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

16 A8. The purpose of my testimony is to present the Unbundled Cost of Service (UCOS)  
17 studies for DTE Electric's projected test year ending December 31, 2026. In  
18 addition, I support revenue requirement calculations for: (1) customer-related costs,  
19 (2) capacity charge by customer class, and (3) Infrastructure Recovery Mechanism  
20 (IRM) by voltage class.

21

22 **Q9. Are you sponsoring any exhibits in this proceeding?**

23 A9. Yes. I am supporting the following exhibits:

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| 1  | <u>Exhibit</u> | <u>Schedule</u> | <u>Description</u>                              |
|----|----------------|-----------------|-------------------------------------------------|
| 2  | A-16           | F1.1            | UCOS, Production by Customer Class,             |
| 3  |                |                 | TME December 31, 2026                           |
| 4  | A-16           | F1.2            | UCOS, Distribution by Voltage Class,            |
| 5  |                |                 | TME December 31, 2026                           |
| 6  | A-16           | F1.3            | UCOS, Functionalization and Allocation Overview |
| 7  | A-16           | F1.4            | Customer Charges by Voltage Class               |
| 8  | A-16           | F1.5            | Capacity Charge Revenue Requirement by Customer |
| 9  |                |                 | Class / SRM Capacity Charge                     |
| 10 | A-33           | X6              | IRM - Distribution Operations - Revenue         |
| 11 |                |                 | Requirement by Voltage Class                    |

12

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

14 A10. Yes, they were.

15

16 **Q11. Can you provide an overview of your testimony and recommendations in this**  
17 **proceeding?**

18 A11. Below is a summary of my testimony and recommendations:

- 19 • DTE Electric's forecasted test year UCOS studies incorporate the allocation
- 20 methodologies, which are generally summarized in Table 1. In this context, in
- 21 which CP stands for Coincident Peak, 12 represents an average of twelve
- 22 months, and 4 represents an average of the four summer months, June through
- 23 September;

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1

**Table 1. Summary of Allocation Methodologies in UCOS**

| <b>Cost Type</b> | <b>Proposed Method</b>                   |
|------------------|------------------------------------------|
| Production Plant | 4CP 75-0-25                              |
| Transmission O&M | 12CP 100-0-0                             |
| Fuel             | 12CP 0-0-100                             |
| Distribution     | Various (by voltage class)               |
| Customer-related | Various; Uncollectibles by total revenue |

2

3

4

5

6

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14

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16

17 **Q12. How is your testimony organized?**

18 A12. My testimony consists of the following six parts:

19 Part I – Forecast Unbundled Cost of Service Studies

20 Part II – Cost Allocation Methods

21 Part III – Customer Charge Costs

22 Part IV – Capacity Charge Revenue Requirement and SRM Capacity Charge

Line  
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1 Part V – IRM Distribution Revenue Requirement by Voltage Class

2

3 **Part I: Forecast Unbundled Cost of Service Studies**

4 **Q13. What is a fully allocated embedded UCOS?**

5 A13. A UCOS allocates all items of utility property and cost to determine the fully  
6 allocated embedded cost of service for each consolidated customer class of service  
7 and shows each customer class's share of costs by major function, such as Power  
8 Supply and Distribution.

9

10 **Q14. What is the objective of a UCOS?**

11 A14. The objective of a UCOS is to assign all costs required to serve customers among  
12 each customer class in a fair and equitable manner. This assignment of costs  
13 reflects the engineering and operating characteristics of the electric utility system  
14 and generally results in the costs of the system being allocated to those who caused  
15 the costs to be incurred.

16

17 **Q15. What process steps are typically performed in developing a UCOS?**

18 A15. The typical process to develop a UCOS consists of three steps: functionalization,  
19 classification, and allocation. Functionalization assigns all costs to the major  
20 functions, i.e., Power Supply and Distribution. Classification divides these costs  
21 into customer-related costs, demand-related costs, and energy-related costs. The  
22 sum of these three types of costs within a given class is the cost to serve that specific  
23 class. The last step, allocation, apportions the cost classifications to the respective  
24 customer classes based upon each class's responsibility for the incurrence of these  
25 costs.



Line  
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1 **Q16. What functions did you use in the cost studies?**

2 A16. The major utility functions used in the cost studies are Power Supply (Generation  
3 and Transmission) and Distribution. Power Supply includes costs associated with  
4 the Company's generating plants, fuel, purchased power and the expense associated  
5 with transmission services provided to DTE Electric by the Midcontinent  
6 Independent System Operator (MISO) and the International Transmission  
7 Company (ITC). Distribution includes the costs associated with the Company's  
8 distribution system that generally operates at voltages of 40 kV and below.  
9 Additionally, it includes customer service costs.

10

11 **Q17. How does the UCOS functionalize DTE Electric's costs?**

12 A17. In Exhibit A-16, Schedule F1.3 page 1 titled "Functionalization and Allocation  
13 Overview", I present an overview of the approach used to functionalize the  
14 Company's costs. The MPSC Uniform System of Accounts (USofA) governs  
15 utility accounting for ratemaking purposes and serves as the basis for  
16 functionalizing direct costs. For example, the USofA requires utilities to record  
17 generating plant costs in accounts 310 through 359 and the associated operation  
18 and maintenance (O&M) expense in accounts 500 through 557. These costs are  
19 directly assigned to the power supply function. Similarly, the USofA requires  
20 utilities to record distribution plant costs in accounts 360 through 373 and O&M  
21 costs in accounts 580 through 598 that are directly assigned to the distribution  
22 function.

23 The O&M costs in accounts associated with providing customer service are directly  
24 assigned to distribution because they apply whether a customer receives power  
25 supply from DTE Electric or an alternative electric supplier (AES). Because DTE

Line  
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1 Electric has divested its transmission plant, the only USofA accounts designated  
2 for transmission utilized by DTE Electric are the plant costs associated with  
3 generator step-up transformers. These costs are directly assigned to power supply.  
4 In addition, power supply includes the expense charged to account 565,  
5 “Transmission of Electricity by Others” including MISO charges. The property tax  
6 associated with production plant is directly assigned to power supply based on tax  
7 information provided by the Company’s Property Tax Department. A share of the  
8 property tax associated with general and intangible plant is allocated to power  
9 supply in proportion to the power supply-related general and intangible plant and  
10 the remaining balance is assigned to distribution. Indirect costs are comprised of  
11 general and intangible plant costs recorded in accounts 303 and 389 through 399,  
12 Administrative and General (A&G) expense in accounts 920 through 935, taxes,  
13 and working capital. The study also includes a credit for miscellaneous revenue,  
14 which is applied to the appropriate functional component based on a combination  
15 of direct assignment and allocation.

16

17 The Company functionalized General and Intangible (G&I) plant in the Forecast  
18 UCOS following the G&I direct assignment study utilized in Case No. U-21534.

19

20 **Q18. How are the remaining indirect costs and miscellaneous revenues**  
21 **functionalized in the Forecast UCOS?**

22 A18. A&G expense is functionalized using the direct labor cost. Working capital is  
23 functionalized using allocators appropriate to each of the asset and liability line  
24 items. For example, fuel inventory is directly assigned to power supply and

Line  
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1 accounts receivable is functionalized based on net plant. Miscellaneous revenue is  
2 functionalized using a combination of direct assignment and allocation.

3

4 **Q19. What is shown on pages 2 to 28 of Exhibit A-16, Schedule F1.3?**

5 A19. Pages 2 through 28 of Schedule F1.3, "Functionalization and Allocation Overview"  
6 provide a detailed list of the functionalization factors and allocation methodologies  
7 used in the development of the UCOS study. The column titled "Func. Factor"  
8 identifies the functionalization method applied to the cost or revenue on that  
9 specific line. The "Prod Alloc" and "Dist Alloc" columns identify the allocation  
10 number being applied, and the "Prod Alloc Description" and "Dist Alloc  
11 Description" columns show a brief description of the allocation method.

12

13 **Q20. How does the Forecast UCOS allocate costs to the various customer classes?**

14 A20. In general, the allocation schedules used for each function are intended to reflect  
15 the load that utilizes the infrastructure associated with that function.

16

17 **Q21. What method was used to allocate production plant-related costs and  
18 transmission O&M costs in the Forecast UCOS?**

19 A21. The Forecast UCOS used the 4CP 75-0-25 method of cost allocation for production  
20 plant-related costs and 12CP 100-0-0 for transmission O&M costs, both of which  
21 are the same methods as those approved in Case No. U-21534. For plant-related  
22 costs, the first component is the average of the four monthly coincident peaks  
23 weighted 75%, the second component is the energy use coincident with the MISO  
24 on-peak period weighted 0%, and the third component is the total energy use  
25 weighted 25%, i.e., 4CP 75-0-25. For transmission O&M, the first component is

Line  
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1 the average of the 12 monthly coincident peaks weighted 100%, the second  
2 component is the energy use coincident with the MISO on-peak period weighted  
3 0%, and the third component is the total energy use weighted 0%, i.e., 12CP 100-  
4 0-0.

5

6 **Q22. Does the UCOS develop costs for each individual rate schedule?**

7 A22. No, it does not. The allocation process apportions costs to classes of service that  
8 are comprised of one or more individual rate schedules.

9

10 **Q23. How are the allocation schedules used in the UCOS developed?**

11 A23. The allocation schedules in the UCOS are either developed externally to the UCOS  
12 model or generated internally in the UCOS model. The externally developed  
13 allocation schedules are based on customer class parameters, such as the number of  
14 customers, customer energy use and customer demand, and serve as inputs to the  
15 UCOS. The internally generated allocation schedules are calculated within the  
16 UCOS model and are based on previously allocated plant investment and/or O&M  
17 expense. An example of an internal allocation schedule is schedule 521,  
18 "Distribution Plant-In-Service." This schedule reflects the sum of the class  
19 allocations of distribution plant in service from each USofA account, some of which  
20 are further subdivided by voltage level.

21

22 **Q24. What is the source for the externally developed allocation schedules used in**  
23 **the UCOS?**

24 A24. The UCOS contains 16 basic externally developed allocation schedules. Of these  
25 16 schedules, 11 are developed and supplied by Company Witness Gerdes and are

Line  
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1 described in his testimony. I develop the other five schedules organized in four  
2 groups: 1) Schedule 800 is based on the number of customers in each class, derived  
3 using data from the Company's billing system, 2) Schedules 370T and 370A are  
4 based on the number of meters (traditional and advanced metering infrastructure  
5 (AMI), respectively) associated with each class and the approximate average cost  
6 of the metering equipment associated with each class, 3) Schedule 370C is used to  
7 allocate meter related costs; this is a combination of Schedules 370T and 370A, and  
8 4) Schedule 402, total revenues by class, is an aggregate of the production and  
9 distribution present revenues (allocators 400 and 401), and is used to allocate  
10 uncollectible expense.

11

12 **Q25. How are Distribution System costs allocated within the UCOS?**

13 A25. The direct distribution costs are allocated based on Schedules 201 - 205. The plant-  
14 related costs are allocated on the schedule appropriate to the voltage level at which  
15 the equipment operates. Distribution O&M expense is allocated based on the  
16 corresponding plant-related cost. For example, overhead lines maintenance  
17 expense (account 593) is allocated based on the sum of plant-in-service for poles  
18 and fixtures (account 364A), overhead conductors (account 365A), and overhead  
19 services (account 369A). The cost of some components within distribution, such  
20 as those associated with single customer substations and street-lighting, are directly  
21 assigned to the voltage cost of service class.

22

23 **Q26. How are the indirect costs allocated within the UCOS?**

24 A26. As stated in my discussion of functionalization, indirect costs are comprised of  
25 general and software plant costs recorded in accounts 303 and 389 through 399,

Line  
No.

1 A&G expense in accounts 920 through 935, taxes, and working capital. The  
2 functionalized general and intangible plant costs are allocated based on the  
3 corresponding functional plant in service. In other words, the general and  
4 intangible plant costs associated with power supply are allocated based on  
5 production plant in service. The general and intangible costs associated with  
6 distribution are allocated based on distribution plant in service. Property taxes are  
7 allocated based on the corresponding functional plant in service. The  
8 functionalized A&G and payroll taxes are allocated based on the corresponding  
9 functional labor ratios. The working capital allocations are driven by the numerous  
10 allocators associated with each of the line items that comprise working capital;  
11 many of those line items are the sum of several other lines.

12

13 **Q27. What forecast test year was used for the forecast UCOS?**

14 A27. The forecast test year is 12 months ending December 31, 2026.

15

16 **Q28. What is the main source of the financial information used to produce the**  
17 **forecast UCOS?**

18 A28. I used the financial information supplied by Company Witness Uzenski.

19

20 **Q29. Do the levels of historic investment for each of the distribution accounts within**  
21 **the Cost of Service match the figures as they are typically presented in the**  
22 **Company's financial records and Form P-521?**

23 A29. Not entirely. Although the total distribution investment matches the Company's  
24 financial records, the levels of investment for some distribution accounts within the  
25 UCOS do not match. These accounts do not match because I break out separately

Line  
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1 the cost of equipment that operates at sub-transmission voltage (24/40 kV) and  
2 apply allocation methods that reflect the engineering and operating characteristics  
3 of the associated equipment and expense. This redistribution of investment to the  
4 accounts in which it was classified prior to the Company's reclassification of 24/40  
5 kV from 350 series accounts (Transmission) to 360 accounts (Distribution) is  
6 necessary to properly allocate the associated costs. A reclassification for  
7 accounting purposes does not change the engineering and operating characteristics  
8 of the associated equipment and expense.

9

10 **Q30. Why did the Company reclassify the 24/40 kV investment in the first place?**

11 A30. This reclassification was the result of the Order in MPSC Case No. U-11337 and  
12 was pursued to comply with FERC Order 888.

13

14 **Q31. What does Exhibit A-16, Schedule F1.1 show?**

15 A31. Schedule F1.1, "Unbundled Cost of Service, Production by Customer Class TME  
16 December 31, 2026" summarizes the results of the Year Ended December 31, 2026,  
17 UCOS for Production. It shows the production related revenue  
18 deficiency/(sufficiency) associated with each consolidated cost of service rate class.  
19 This exhibit shows the Company experienced a base production revenue deficiency  
20 of \$121.7 million as shown on page 1, line 27, col. (a) of Schedule F1.1. This  
21 deficiency includes an additional \$141.1 million revenue deficiency related to the  
22 Monroe Regulatory Asset. The revenue deficiency related to the Monroe  
23 Regulatory Asset is calculated by Company Witness Vangilder and is reflected on  
24 line 10 of Exhibit A-11, Schedule A1. I functionalized the Monroe Regulatory  
25 Asset revenue deficiency as production because it consists of production plant costs

Line  
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1 and allocated it to various customer classes utilizing the same allocator used to  
2 allocate production plant costs (4CP 75-0-25).

3

4 **Q32. Can you explain the Rider 10 Tax Gross-Up Adjustment on line 29 of Exhibit**  
5 **A-16, Schedule F1.1?**

6 A32. The Rider 10 (R10) tax gross-up adjustment on line 29 of Exhibit A-16, Schedule  
7 F1.1 is a calculation that was approved by the Commission on page 298 of the Order  
8 in Case No. U-21297 dated December 1, 2023. While the net impact of this  
9 adjustment to total production revenue requirement is zero, it is a necessary step to  
10 eliminate the R10 administrative charge, as required by the Commission on page  
11 431 of the Order in Case No. U-20836 dated November 18, 2022. The methodology  
12 proposed in the instant case is consistent with the calculation utilized in the rates  
13 approved by the Commission in their Order in Case No. U-21534 dated January 23,  
14 2025.

15

16 **Q33. What does Exhibit A-16, Schedule F1.2 show?**

17 A33. Schedule F1.2, "Unbundled Cost of Service, Distribution by Voltage Class TME  
18 December 31, 2026" summarizes the results of the year ending December 31, 2026,  
19 UCOS for Distribution. It shows the distribution related revenue  
20 deficiency/(sufficiency) associated with each cost of service voltage class. This  
21 exhibit shows the Company experienced a base distribution revenue deficiency of  
22 \$452.3 million as shown on page 1, line 27, col. (a) of Schedule F1.2. This  
23 deficiency includes an additional \$11.9 million revenue deficiency related to the  
24 Tree Trim Surge. This revenue deficiency related to the return on the Tree Trim  
25 Regulatory Asset is calculated by Company Witness Vangilder and is reflected on



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1 line 9 of Exhibit A-11, Schedule A1. I functionalized the Tree Trim Surge as  
2 distribution because it is associated with the expenses in O&M account 593  
3 (Maintenance of Overhead Lines) and allocated it to various voltage classes using  
4 the same allocator used to allocate account 593.

5

6 **Q34. What are the results shown on Exhibit A-16, Schedules F1.1 and F1.2?**

7 A34. The sum of the base revenue deficiencies on line 27 of Schedules F1.1 and F1.2  
8 equals \$574.1 million and matches the total revenue deficiency on Exhibit A-11,  
9 Schedule A-1, supported by Company Witness Vangilder. The base revenue  
10 deficiency is then adjusted by D13 incremental revenues totaling \$0 as shown on  
11 line 28 of each schedule in Exhibit A-16 (F1.1 and F1.2). to arrive at the total  
12 revenue deficiency/(sufficiency) for ratemaking purposes on line 30 and total base  
13 revenue requirement on line 31. Lines 30 and 31 of Exhibit A-16 Schedule F1.1  
14 and Schedule F1.2 are used by Company Witnesses Turner, Willis, and Hartley to  
15 calculate rates.

16

17 **Part II: Cost Allocation Methods**

18 **Q35. Are the cost allocation methods used to produce the forecast UCOS consistent**  
19 **with those approved by the Commission in Case No. U-21534?**

20 A35. Yes.

21

22 **Q36. What allocation methods did you use for the forecast UCOS in this**  
23 **proceeding?**

Line  
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1 A36. I performed UCOS studies for the forecast test year based on the proposed  
2 allocation methods summarized in Table 2. These allocation methods are the same  
3 as those approved in Case No. U-21534:  
4

5 **Table 2. Summary of Allocation Methodologies in UCOS**

| <b>Cost Type</b> | <b>Proposed Method</b>                   |
|------------------|------------------------------------------|
| Production Plant | 4CP 75-0-25                              |
| Transmission O&M | 12CP 100-0-0                             |
| Fuel             | 12CP 0-0-100                             |
| Distribution     | Various (by voltage class)               |
| Customer-related | Various; Uncollectibles by total revenue |

6

7 **Q37. What allocation method are you using for Production Plant?**

8 A37. I continue using the 4CP 75-0-25 method approved in the Commission's January  
9 23, 2025, Order in Case No. U-21534. This method has been approved in DTE  
10 Electric's last eight general rate cases (e.g., Case Nos. U-17767, U-18014, U-  
11 18255, U-20162, U-20561, U-20836, U-21297 and U-21534).  
12

13 **Q38. What allocation method are you using for Transmission O&M?**

14 A38. The transmission system that serves DTE Electric's service territory is owned by  
15 ITC. DTE Electric's share of the cost of providing transmission service to its  
16 customers is determined based upon a 12CP load ratio share. Therefore, an  
17 allocation basis that relies on the 12CP 100% demand is reflective of cost causation  
18 and was utilized in the final rates approved in the Commission's Order in Case No.  
19 U-21534 dated January 23, 2025.  
20

21 **Q39. What is DTE Electric's allocation methodology for distribution?**

Line  
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1 A39. The Company uses three allocation bases for distribution: demand, customer, and  
2 those based on special studies. Demand based allocators are used for poles, wires,  
3 conduit, substations, transformers, and other equipment that comprise the  
4 distribution system. Customer based allocators are used for service drops and  
5 billing. A special study was utilized to develop the basis for allocating meters. The  
6 proposed allocation method selected for distribution allocates distribution by  
7 voltage class. Specifically, distribution is broken into residential secondary,  
8 commercial secondary, primary, sub-transmission, transmission, and lighting (E-1  
9 Street Lighting, D-9 Outdoor Protective Lighting (OPL), and E-2 Traffic Signals).  
10 Distribution allocation methods in the instant case are consistent with those  
11 approved in the Commission's Order in Case No. U-21534 dated January 23, 2025.

12

13 **Q40. Why is lighting maintained as a separate class as opposed to being grouped by**  
14 **voltage?**

15 A40. Unlike the distribution service for other classes, the lighting class has a significant  
16 amount of dedicated infrastructure costs that should be directly assigned.

17

18 **Q41. What determines cost causation for distribution?**

19 A41. For distribution, the parameters used to design and build the system determine cost  
20 causation. The principal system design parameters are the geographic area to be  
21 covered, and the maximum demand placed on the system at a given voltage level.  
22 Because rebuilding a circuit is expensive, distribution planning must consider  
23 future load growth and reliability. Also, many of the components of the distribution  
24 system are standardized to achieve efficiencies. Consequently, circuits initially  
25 have extra capacity, but once demand reaches a certain threshold, either the circuit

Line  
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1 configuration must be changed, or the components replaced with components  
2 having greater capacity. To meet reliability criteria, distribution planning engineers  
3 sometimes add alternate lines and transformers. This redundancy maximizes, to  
4 the degree practical, the Company's ability to maintain service in the face of storms  
5 and other outage related events. Because of the need to consider future growth,  
6 reliability, and standardized components, the capacity of the system will generally  
7 support loads greater than those initially experienced. Therefore, once installed,  
8 distribution system costs are generally not affected by increases or decreases in  
9 either demand or energy until the circuit limit (demand threshold) is approached.  
10 However, when viewed prospectively, distribution system design cost is caused  
11 (driven) by the number of customers served and the maximum demand placed on  
12 the system at a given voltage level.

13

14 **Q42. How did you produce UCOS by voltage level?**

15 A42. I used the allocation schedules developed by Company Witness Gerdes and  
16 distribution revenues by voltage for customers served at voltage levels primary and  
17 above developed by Company Witness Turner. In addition, I performed  
18 calculations to break out the UCOS inputs that I prepare by voltage level. I used  
19 these inputs to produce the proposed UCOS that allocates and displays costs by  
20 voltage level.

21

22 **Q43. How are you allocating costs associated with uncollectible expense?**

23 A43. The costs associated with uncollectible expense are allocated based on total  
24 revenues, as previously discussed. This allocation method is consistent with the

Line  
No.

1 methodology utilized in the final rates approved by the Commission's Order in  
2 Case No. U-21534 dated January 23, 2025.

3

4 **Q44. How are you allocating merchant fees within Account 903?**

5 A44. Consistent with the Company's last rate case, Case No. U-21534, residential  
6 merchant fees are directly assigned to the residential secondary class and  
7 commercial merchant fees are directly assigned to the commercial secondary class  
8 in the Company's UCOS. This methodology ensures that no cross subsidization  
9 occurs across cost-of-service rate classes related to merchant fees.

10

11 **Q45. What allocation changes did the Commission adopt in Case No. U-21534?**

12 A45. In the January 23, 2025 Order in Case No. U-21534, the Commission approved the  
13 use of the 4CP 75-0-25 allocation for purchased power capacity costs. In addition,  
14 the Commission directed the Company to submit a new allocator for fuel costs to  
15 ensure consistency in the allocation of purchased power energy and fuel costs.

16

17 **Q46. Are you using the same allocation method for purchased power capacity costs**  
18 **as ordered by the Commission in the preparation of the forecast UCOS in the**  
19 **instant case?**

20 A46. Yes. I use the allocator 255 (4CP 75-0-25) for the allocation of purchased power  
21 capacity costs in the forecast UCOS.

22

23 **Q47. Are you submitting a new allocator for fuel costs as directed by the**  
24 **Commission in the preparation of the forecast UCOS in the instant case?**

Line  
No.

1 A47. Yes. The Company has updated the fuel cost allocator from 12CP 10-0-90  
2 (allocator 192) to 12CP 0-0-100 (allocator 111). This change adheres to the  
3 Commission's Order in Case No. U-21534, which mandates aligning the allocation  
4 of fuel costs with purchased power energy costs, the latter previously allocated  
5 using allocator 111.

6

7 **Part III: Customer Charge Costs**

8 **Q48. How are the costs included within distribution for customer charges classified?**

9 A48. The Electric Utility Cost Allocation Manual, National Association of Regulatory  
10 Utility Commissioners (NARUC Manual) classifies both distribution plant and  
11 expenses as being either demand-related, customer-related, or a combination of the  
12 two (Electric Utility Cost Allocation Manual, NARUC, January 1992). Chapter 6  
13 of the NARUC Manual titled "Classification and Allocation of Distribution Plant"  
14 includes Table 6-1 "Classification of Distribution Plant" and Table 6-2  
15 "Classification of Distribution Expenses". Within both tables and Chapter 6, the  
16 only cost classification types identified are demand and customer; energy is not  
17 listed as a basis for classifying any portion of distribution-related cost. The only  
18 energy-related costs identified are production-related.

19

20 **Q49. Can you describe Exhibit A-16, Schedule F1.4 "Customer Charges by Voltage**  
21 **Class"?**

22 A49. Exhibit A-16, Schedule F1.4 is a one-page exhibit that calculates monthly customer  
23 charges for each voltage level, using the Staff's method approved in the  
24 Commission's January 23, 2025 Order in Case No. U-21534. The related costs are  
25 detailed on the same Exhibit A-16, Schedule F1.4.

Line  
No.

1   **Q50. How did you determine which costs to include on Exhibit A-16, Schedule F1.4**  
2       **“Customer Charges by Voltage Class”?**

3   A50. I included the same cost items reflected on Staff’s Exhibit S-6, Schedule F1.4, from  
4       Case No. U-21534 supported by Staff Witness Pung. I have reflected all the same  
5       line items as Staff’s Exhibit S-6, Schedule F1.4 from Case No. U-21534, with  
6       updated numbers from the proposed UCOS for distribution reflected in this instant  
7       case.

8

9   **Part IV: Capacity Charge Revenue Requirement and State Reliability Mechanism**  
10   **(SRM) Capacity Charge**

11   **Q51. What costs have you included in your calculation of capacity revenue**  
12       **requirement reflected on Exhibit A-16, Schedule F1.5?**

13   A51. The capacity revenue requirement includes all Production related costs per Exhibit  
14       A-16, Schedule F1.1, except fuel, variable O&M, MERC, and certain purchased  
15       power costs explained later in my testimony. This method is consistent with the  
16       methodology approved in the Commission’s Order in Case No. U-21534 dated  
17       January 23, 2025.

18

19   **Q52. Can you describe in more detail the costs reflected on Exhibit A-16, Schedule**  
20       **F1.5, page 1 of 6?**

21   A52. Line 1 of Exhibit A-16, Schedule F1.5, page 1 of 6 exactly matches line 31 from  
22       Exhibit A-16, Schedule F1.1 (UCOS Production). Line 2 is a reduction to the  
23       revenue requirement for fuel included in the Production UCOS. Line 3 is a  
24       reduction for MERC revenue requirement, which is calculated on line 9 of page 6  
25       of the Exhibit A-16 Schedule F1.5. Lines 4 and 5 are a reduction to the revenue

Line  
No.

1 requirement for non-capacity related purchased power. Line 6 is a reduction to the  
2 revenue requirement for variable O&M. Line 9 is a adjustment in revenue  
3 requirement for projected energy sales revenue net of fuel-related costs including  
4 reconciliation, calculated by Company Witness Burgdorf on line 25 of page 1 of  
5 Exhibit A-26, Schedule P3. Line 11 is the calculated total capacity charge revenue  
6 requirement.

7

8 **Q53. How did you calculate MERC revenue requirement on line 3 of the Exhibit A-**  
9 **16, Schedule F1.5, page 1?**

10 A53. This calculation is consistent with the methodology utilized in the final SRM  
11 capacity charge approved by the Commission in the January 23, 2025 Order in Case  
12 No. U-21534. This calculation can be found on page 6 of the same exhibit. MERC  
13 net plant is calculated on lines 1 through 4. I then multiplied net plant by the  
14 weighted average cost of capital on line 5 to determine the return on net plant. Line  
15 7 represents MERC depreciation expense, and line 8 represents MERC property  
16 tax. Line 6 through 8 are summed to calculate the MERC revenue requirement on  
17 line 9.

18

19 **Q54. Did you reduce the capacity charge revenue requirement for any non-capacity**  
20 **related purchased power?**

21 A54. Yes. On lines 4 and 5 on page 1 of Exhibit A-16 Schedule F1.5, I reduced the  
22 capacity charge revenue requirement for non-capacity related purchased power.  
23 The reason for this adjustment is that these costs are not capacity-related; rather,  
24 these purchased power costs are for energy purchased from MISO for Rider 3 and  
25 Rider 10 (line 4) and other energy related purchased power (line 5). For this reason,



Line  
No.

1 the \$466.3 million purchased power expense identified on page 1 line 7 of Exhibit  
2 A-16, Schedule F1.1 is considered to be all capacity except for the \$30.1 million  
3 directly assigned to Rider 10 and \$0.6 million assigned to Rider 3 (which is  
4 included with D11) and \$274.1 million of other energy-related costs. The \$30.8  
5 million non-capacity cost is equal to the sum of the R10 MISO Pricing Option costs  
6 listed on line 21 of Exhibit A-13, Schedule C4 and Voltage Level Adder costs listed  
7 on line 22 of Exhibit A-13, Schedule C4, sponsored by Company Witness Willis.  
8 The \$274.1 million of other energy-related purchased power is the difference  
9 between the capacity related purchased power costs of \$161.4 million calculated by  
10 Witness Burgdorf on line 7, column b of Exhibit A-26, Schedule P3, and the total  
11 remaining purchased power costs of \$435.5 million (\$466.3 million less \$30.8  
12 million directly assigned to D11 and Rider 10).

13

14 **Q55. Did you make any other adjustments?**

15 A55. Yes. I also adjusted for variable O&M on page 1 line 6 of Exhibit A-16, Schedule  
16 F1.5.

17

18 **Q56. Which costs did you include on line 6 of Exhibit A-16, Schedule F1.5 for**  
19 **variable O&M?**

20 A56. I calculated variable O&M on Exhibit A-16, Schedule F1.5, page 5. I included the  
21 costs in Account 501 (Fuel Handling) and the non-labor portions of Accounts 502  
22 (Steam Expenses), 505 (Electric Operation Expenses), 519 (Coolants and Water),  
23 520 (Steam Expenses), 538 (Electric Maintenance Expenses) and 548 (Peaker  
24 Expenses).

Line  
No.

1 **Q57. Why did you only include the non-labor portion in variable O&M for accounts**  
2 **other than 501?**

3 A57. The NARUC Manual describes the classification of production plant in Chapter 4.  
4 According to this Chapter, accounts 502, 505, 519 and 538 should be classified  
5 between demand and energy based on labor expenses and materials expenses.  
6 Labor expenses are considered demand-related, while material expenses are  
7 considered energy-related. Therefore, I determined that only the material related  
8 costs are variable, and that accounts 520 and 548 should be handled in the same  
9 manner. On page 35 in Chapter 4, the NARUC Manual states:

10

11 *Production plant costs are either fixed or variable. Fixed production*  
12 *costs are those revenue requirements associated with generating plant*  
13 *owned by the utility, including cost of capital, depreciation, taxes, and*  
14 *fixed O&M. Variable costs are fuel costs, purchased power costs and*  
15 *some O&M expenses. Fixed production costs vary with capacity*  
16 *additions, not with energy produced from given plant capacity, and are*  
17 *classified as demand-related. Variable production costs change with the*  
18 *amount of energy produced, delivered, or purchased and are classified*  
19 *as energy-related.*

20

21 **Q58. Why did you only include the above accounts in variable O&M?**

22 A58. Based on my review of the descriptions of the various production O&M accounts,  
23 only the chosen accounts appear to be variable. The descriptions for these accounts  
24 include variable material costs such as lubricants, chemicals, and water.

25

26 **Q59. How did you allocate the Capacity Charge revenue requirement to the various**  
27 **rate classes on Exhibit A-16 Schedule F1.5, pages 1 through 4?**

28 A59. I allocate the Capacity Charge revenue requirement to the various rate classes using  
29 the 200B (4CP) allocator, excluding Rider 10. This methodology was most recently

Line  
No.

1 approved in the Commission's Order in Case No. U-21534. The values for this  
2 allocation schedule are listed on Line 20 of pages 1-4 of Exhibit A-16 Schedule  
3 F1.5. Line 23 of Schedule F1.5 reflects the amounts allocated to customer classes  
4 and is calculated by multiplying line 20 by the total Capacity Charge revenue  
5 requirement of \$2,224.2 million on line 11, divided by 100. Line 24 is the Non-  
6 Capacity revenue requirement and is the difference between line 23 and the total  
7 production revenue requirement on line 25. Line 25, total production revenue  
8 requirement, is equal to line 31 of Exhibit A-16, Schedule F1.1.

9

10 **Q60. Can you describe the SRM Capacity Charge calculation shown in the Exhibit?**

11 A60. The SRM capacity charge calculation starts with the capacity revenue requirement  
12 on line 11 of the exhibit. The calculation of this revenue requirement was  
13 previously described above in my testimony. The capacity in MW derived from the  
14 Company's 2023 10-K filing is shown on line 13. The SRM Capacity Charge per  
15 MW-Year is calculated on line 15 by dividing line 11 by line 13 and multiplying  
16 by 1,000. This SRM Capacity Charge per MW-Day on line 17 is then calculated  
17 by dividing line 15 by 365 days.

18

19 **Part V: IRM Revenue Requirement**

20 **Q61. What is reflected on Exhibit A-33, Schedule X6?**

21 A61. Exhibit A-33, Schedule X6, is a one-page exhibit that reflects the allocation of the  
22 distribution related IRM revenue requirement to the various voltage classes.

23

24 **Q62. What is the source of information utilized in the allocation performed in**  
25 **Exhibit A-33, Schedule X6?**

Line  
No.

1 A62. The total IRM revenue requirement amounts per period detailed in column a, lines  
2 2-4 are sourced from Exhibit A-33, Schedule X4, page 1 that is supported by  
3 Company Witness Vangilder.

4  
5 **Q63. Has the Company applied the allocation methodology approved in prior DTE**  
6 **Electric rate case orders?**

7 A63. Yes. The method used to allocate IRM revenue requirement is consistent with the  
8 methodology approved by the Commission's Order in Case No. U-21534 dated  
9 January 23, 2025.

10

11 **Q64. How did you allocate the proposed distribution related IRM revenue**  
12 **requirement to the various rate classes for 2027, 2028 and 2029 on Exhibit A-**  
13 **33, Schedule X6?**

14 A64. I allocated the proposed distribution related IRM revenue requirement to the  
15 voltage classes for years 2027, 2028 and 2029 using allocation schedule 521T, a  
16 variant of allocator 521, which was modified to exclude transmission. Allocator  
17 521 is calculated within the UCOS and is equal to each voltage classes' share of  
18 distribution related plant. The allocator 521T is used because the components of  
19 the IRM revenue requirement are all plant or plant related. The value of the  
20 allocator is listed on line 1 of Schedule X6. Each voltage classes' share is calculated  
21 by multiplying the total proposed distribution related IRM revenue requirements  
22 listed on column (a), lines 2 (2027) through line 4 (2029) in Schedule X6 by the  
23 allocation percentages on line 1. The proposed IRM revenue requirements listed on  
24 column (a), lines 2 through 4 of Exhibit A-33 Schedule X6 are calculated on line

Line  
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- 1 41, columns (f) through (h) on page 1 of Exhibit A-33, Schedule X4 sponsored by
- 2 Company Witness Vangilder.
- 3
- 4 **Q65. Does this complete your direct testimony?**
- 5 A65. 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-21860

QUALIFICATIONS  
  
AND  
  
DIRECT TESTIMONY  
  
OF  
  
QUINN GERDES

**DTE ELECTRIC COMPANY**  
**QUALIFICATIONS AND DIRECT TESTIMONY OF QUINN GERDES**

Line  
No.

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

2     A1.     My name is Quinn Gerdes (he/him/his). My business address is One Energy Plaza,  
3             Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC,  
4             a subsidiary of DTE Energy Company (DTE Energy), as a Senior Strategist,  
5             Regulatory Affairs.

6

7     **Q2.     On whose behalf are you testifying?**

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

9

10    **Q3.     What is your educational background?**

11    A3.     I received a Bachelor of Arts in Applied Mathematics from the University of Illinois  
12             Urbana Champaign.

13

14    **Q4.     What is your work experience?**

15    A4.     In 2020, I was employed by Accenture, LLC as a Management Consultant in their  
16             Utilities practice. In this role, I supported and advised investor-owned utilities with  
17             the execution of IT infrastructure implementations, developing market strategies  
18             for new energy technologies like renewable based hydrogen. Additionally, I  
19             supported State Energy Offices with grant writing and the development of low-  
20             income electrification programs. In 2024, I began my employment with DTE  
21             Energy as a Senior Strategist in Regulatory Affairs.

22

23    **Q5.     What are your current duties and responsibilities?**

24    A5.     My responsibilities include the development of forecast allocation schedules as  
25             well as supporting activities related to the execution of DTE Electric's rate strategy.

Line  
No.

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

3 A6. No.

4

5 **Purpose of Testimony**

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

7 A7. The purpose of my testimony is to address Forecast Allocation Schedules and  
8 present analysis on the transition of Rate Schedule D1.6 customers to Rate Schedule  
9 D1.11.

10 • **Forecast Allocation Schedules:** Support the allocation schedules and  
11 methodology utilized by the Company for the 12-month period ending  
12 December 31, 2026.

13 • **D1.6 Rate Schedule Transition Analysis:** Detail the methods and results of  
14 analysis done on the transition of Rate Schedule D1.6 customers to Rate  
15 Schedule D1.11, responsive to the requirements set forth by the Commission in  
16 Case No. U-21534.

17

18 **Q8. Are you sponsoring any exhibits in this proceeding?**

19 A8. Yes. I am supporting the following exhibits:

| Exhibit | Schedule | Description                                                                  |
|---------|----------|------------------------------------------------------------------------------|
| A-5     | E2       | Cost of Service Allocation Methodology Diagram                               |
| A-5     | E3       | Allocation Schedule Description                                              |
| A-17    | G1.1     | Forecast Energy Allocation Schedules – 12 months<br>ending December 31, 2026 |

24



|   |      |      |                                                  |
|---|------|------|--------------------------------------------------|
| 1 | A-17 | G1.2 | Demand and Energy Allocation Percentages by Rate |
| 2 |      |      | Class                                            |

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

6

## 8

11 A10. Yes. To aid in understanding and to avoid confusion, I am defining the following  
12 terms that I use throughout my testimony:

- Customer Class or Class of Service: A set of customers with similar characteristics who have been grouped for the purpose of setting an applicable rate for electric service.
- Total System Analysis (TSA): The study of all customer classes that identifies the hourly demand values for all hours of the year. This is the foundation of allocation schedules.
- Energy: The total kilowatt-hours (kWh) or megawatt-hours (MWh) supplied to or used by an individual customer or customer class.
- Demand: The rate at which electric energy is used at a given instant or averaged over a designated time interval. Typically, demand is expressed in kilowatts (kW) or megawatts (MW).
- Service Area System Peak Demand: The highest hourly demand for all customers (full service and choice) served on the DTE Electric distribution

Line  
No.

- 1 system within a specific period (day, month, year, etc.). Service Area
- 2 System Peak Demand is commonly referred to as the ‘system peak.’
- 3     ▪ Bundled Peak Demand: The highest hourly demand for all full service
- 4 customers served by DTE Electric’s production system within a specific
- 5 period (day, month, year, etc.). Bundled Peak Demand is commonly
- 6 referred to as ‘bundled peak.’
- 7     ▪ Coincident Peak Demand (CP): The demand of any customer class within a
- 8 specific period (day, month, year, etc.) that occurs at the same time as the
- 9 system peak or the bundled peak demand for the same period.
- 10    ▪ 12CP: The demand value derived by averaging the actual demand values
- 11 registered on the monthly system bundled peak hours for January through
- 12 December for each customer class.
- 13    ▪ 4CP: The demand value derived by averaging the actual demand values
- 14 registered on the monthly bundled peak hours for June through September
- 15 for each customer class.
- 16    ▪ Non-Coincident Peak Demand: The maximum demand of any customer
- 17 class within a specific period but not necessarily occurring at the time of the
- 18 system peak demand for that period.
- 19    ▪ Losses: A term used to define the difference between the electrical energy
- 20 delivered to a customer (or a given point on the electrical distribution
- 21 system) and the amount of electrical energy that must be generated at the
- 22 power plant to serve that customer. In other words, losses refer to the
- 23 difference in the amount of power generated from the power plant and the
- 24 point of delivery.

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Line  
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1     **Q11. What are the data sources for the allocation schedules?**

2     A11. The forecasted test year allocation schedules are based on 2023 customer class sales  
3           data obtained from the 2023 Total System Analysis (TSA). The forecast allocation  
4           schedules are based on the energy sales forecast for the residential, commercial,  
5           and industrial classes supported by Company Witness Leuker. Additionally, the  
6           street lighting and traffic signals sales forecast is supported by Company Witness  
7           Hartley, and the forecast billing determinants supported in my exhibits. These sales  
8           levels are shown with losses on Exhibit A-17, Schedule G1.1.

9

10    **Q12. What is the purpose of the allocation schedules you have developed?**

11    A12. The allocation schedules are developed using customer class sales, data from  
12           Advanced Metering Infrastructure (AMI), and quantitative methods to determine  
13           the extent (expressed as a percentage) that each customer class uses the various  
14           portions of the electrical system. In this case, the customer class usage percentages  
15           determined in the allocation schedules are one of the inputs used by Company  
16           Witness Cejas Goyanes to determine customer class cost responsibility.

17

18           Since not all customer classes utilize the full distribution system to take delivery of  
19           electrical service, the allocation schedules are developed to assign only the portions  
20           of the system used by each customer class. Exhibit A-5, Schedule E2, includes a  
21           diagram which reflects the applicability of allocation schedules to customer class.

22

23    **Q13. How did you develop the allocation schedules?**

24    A13. I developed 13 forecast allocation schedules for use in cost-of-service studies as  
25           described in Exhibit A-5, Schedule E3. Each schedule was designed to allocate

Line  
No.

1 costs based on each customer class's utilization of a particular part of the electrical  
2 system, which is the industry standard practice for developing allocation schedules.

3  
4 Schedule 100, shown in Exhibit A-17, Schedule G1.2, is based on the class's  
5 forecasted energy consumption. The remaining 12 allocation schedules described  
6 in Exhibit A-5, Schedule E3, are based on the forecasted demand that each customer  
7 class places on the various portions of the electrical system. The allocation  
8 schedule numbers and the associated portion of the electrical system they represent  
9 are shown schematically on Exhibit A-5, Schedule E2.

10

11 **Q14. Why does the measurement basis differ for each allocation schedule?**

12 A14. The measurement basis for each allocation schedule is based on the design and  
13 service requirements for each portion of the electrical system. Specifically,  
14 forecasted energy is used for Power Plant Energy Production (Schedule 100) to  
15 serve customers. As customers use energy, they create a demand (rate at which  
16 energy is used and/or delivered) on the system.

17

18 The output capacity of power plant production is designed considering the peak  
19 demand requirements of the production system, measured as the bundled peak  
20 demand. Production Schedule 200A is measured based on forecasted bundled 12  
21 CP, while Schedule 200B is measured based on the forecasted bundled 4CP.  
22 Schedule 201 – Input to Transmission Substation is based on the forecasted 12CP  
23 of the of the Service Area.

Line  
No.

1 Schedules 202A, 202B, 202C, 203A, 203B, 203C, 204, and 205 refer to substations,  
2 high voltage lines, and transformers, which are designed to carry the maximum load  
3 required by the customer classes they serve, regardless of whether the class  
4 maximum demand occurs at the same time or a different time as the system peak.  
5 The forecasted non-coincident peak and individual customer maximum peak  
6 demand are the measurement bases for these allocation schedules.

7

8 Low voltage secondary lines are designed to serve the absolute maximum demand  
9 level of the customers they feed. Therefore, Schedule 300 is based on the forecasted  
10 sum of the individual customer maximum demands.

11

12 **Q15. How was the 2023 TSA used to develop the demand values determined for the**  
13 **forecast allocation schedules?**

14 A15. The basis for the forecast allocation schedules developed for this instant case are  
15 the forecasted net sales values presented in Company Witness Leuker's Exhibit A-  
16 15, Schedule E1. However, because Company Witness Leuker's system peak  
17 demand forecast does not include the associated customer class level demand  
18 values necessary for allocation schedule development, it was necessary to develop  
19 these corresponding demand values by customer class. This was achieved by  
20 applying historical load factors to the forecast energy values using industry standard  
21 load research principles to derive demand values using energy and load factor.  
22 Therefore, forecast demands were calculated by dividing the net forecast energy  
23 values (without losses) by the product of the historic load factor and annual hours

Line  
No.

1   **Q16. How were the appropriate historic load factors determined?**

2   A16. A 5-year average load factor was derived from years 2019-2023 and used for each  
3       cost-of-service class.

4

5   **Q17. Why is using the 5-year average historical load factor a better representation**  
6       **of the class's performance than the actual 2023 historic load factor?**

7   A17. Using the 5-year average load factor accounts for any abnormalities in any single  
8       year and smooths out any variability due to weather, or other anomalies such as  
9       economic conditions.

10

11   **Q18. Why is using average historical load factors a reasonable method of**  
12       **determining forecast demand values?**

13   A18. Using average historical load factors is a reasonable method for determining load  
14       factor because there is a mathematical relationship between energy, load factor, and  
15       demand. Forecasting demand is necessarily a function of forecasted sales and  
16       forecasted load factors. Utilizing load factors to forecast demand values maintains  
17       the relationship between energy and demand.

18

19   **Q19. How did you develop the forecast allocation schedules?**

20   A19. I applied the 5-year average load factors to the forecasted energy sales received  
21       from Company Witness Leuker. This method produced the forecast schedules for  
22       the period from January 2026 to December 2026, as shown in Exhibit A-17,  
23       Schedule G1.1.

Line  
No.

1     **Q20. How are line losses used in forecast allocation schedules?**

2     A20. Line loss factors are used as a multiplier in allocation schedules to increase the  
3           energy or demand value for a given schedule to reflect the amount of production  
4           needed to serve the customer class. Line losses were measured by voltage level,  
5           allowing allocation schedules to accurately reflect demands on the system caused  
6           by different classes of customers.

7  
8     **Q21. Are the allocation schedules defined in your testimony developed using**  
9           **established principles and methods?**

10    A21. Yes. I used the industry recognized and accepted load research principles. The  
11           methods I used are consistent with those used by the Company in all its electric  
12           general rate cases filed since 2014.

13

14     **Analysis of Rate Schedule D1.6 Transition to D1.11**

15     **Q22. Why are you providing this analysis?**

16    A22. In Case No. U-21297, the Company proposed to transition customers served under  
17           Rate Schedule D1.6 to the standard residential Rate Schedule D1.11 and expand  
18           the low-income assistance (LIA) credit to all residential base rates beyond just Rate  
19           Schedule D1.6. The Commission's Order in Case No. U-21297 dated December 1,  
20           2023, pages 312-313, declined to adopt the proposal and directed the Company to:

21

22                   [C]onduct an impact study comporting to the DAAOs' recommended report  
23                   outline before retiring Rate Schedule D1.6 and transitioning customers to  
24                   Rate Schedule D1.11.

25

26           Subsequently, the Company provided the impact study in Case No. U-21534. Based  
27           on the findings, the Commission approved the transition of Rate Schedule D1.6 to



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1 Rate Schedule D1.11 and the expanded availability of the LIA credit. In the January  
2 23, 2025 Order in Case No. U-21534, pages 394 and 468, the Commission directed  
3 the Company:

4  
5 [I]n its next general rate case, DTE Electric shall include, in relation to the  
6 transition from Rate Schedule D1.6 to Rate Schedule D1.11, an analysis of  
7 shutoff information, an analysis of the factors impacting household ability  
8 to shift usage, and regression analyses.  
9

10 I am supporting the Company's responsive regression analysis and the analysis of  
11 factors impacting household ability to shift usage. Company Witness Sparks  
12 discusses the related shutoff analysis.  
13

14 **Q23. What bill impact analysis did the Company provide in Case No. U-21534?**

15 A23. The analysis compared the actual annual bills of 2022 Rate Schedule D1.6  
16 customers (not including credits) to the equivalent bill on Rate Schedule D1.11  
17 calculated using their actual 2022 usage. It found that nearly two-thirds of Rate  
18 Schedule D1.6 customers would have had a reduced bill on Rate Schedule D1.11.  
19

20 **Q24. What were the analysis requirements set forth in the Commission's January**  
21 **23, 2025 Order issued in Case No. U-21534?**

22 A24. On page 394 of the January 23, 2025 Order in Case No. U-21534, the Commission  
23 directed DTE Electric to perform an analysis of shutoff information, factors  
24 impacting customers' ability to shift usage and a regression analysis.  
25

26 To ensure the Company is being responsive to the Commission's requirement on  
27 regression analysis, the Company referenced guidance from Case No. U-21297.  
28 Therefore, the Company reviewed DAAO Witness Koeppel's recommendations

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1 and used his recommendations on pages 65-66 of his revised direct testimony in  
2 Case No. U-21297 (Koeppel, 6T 4021-4022) to further enumerate the requirements  
3 for the regression analysis:

4  
5 [U]tilizing spatial analysis of census tracts and regression analysis to determine  
6 if income, race, assistance program participation, and other factors are  
7 associated with costs shifts from the transition to D1.11.  
8

9 Ability to shift usage

10 **Q25. What approach did you use to analyze the factors impacting a customer's**  
11 **ability to shift usage?**

12 A25. I analyzed the results from surveys conducted during the Company's Advanced  
13 Customer Pricing Pilot (ACPP). The ACPP was a pilot program approved by the  
14 Commission prior to the implementation of Rate Schedule D1.11. It tested two  
15 time-of-use (TOU) rates along with an opt-in and opt-out strategy for enrollment  
16 and 220,000 customers were selected for participation. It also segmented and  
17 assessed low-income customers both through usage statistics and survey response.  
18 The discussion here is centered on the customer surveys.

19

20 **Q26. What type of surveying was done during the ACPP?**

21 A26. DTE Electric contracted with a vendor who conducted four surveys on enrollment,  
22 dropout, and post-cooling and post-heating behaviors. The surveys sought to  
23 measure the pilot's impacts on customer behavior, knowledge and energy usage.

24

25 **Q27. How do the results of these surveys pertain to the requirement to "assess the**  
26 **factors affecting a customer's ability to shift their usage"?**

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1 A27. The ACPP's post-cooling and post-heating surveys sought to understand how  
2 customers use their appliances and what factors affect their ability to shift the  
3 appliance use. The survey segmented responses by non-low-income and low-  
4 income customers and asked about their willingness to change behaviors,  
5 knowledge and awareness, and technology use and motivations.

6

7 **Q28. How many responses did the Company receive?**

8 A28. There were 2,213 responses to the post-cooling and post-heating surveys or  
9 approximately a 23% response rate. Of the responses to the surveys, approximately  
10 10 – 12% of respondents were classified as low income, depending on the survey  
11 and question.

12

13 **Q29. Did the low-income customers surveyed suggest different energy usage**  
14 **patterns than non-low-income customers?**

15 A29. Yes. The results found that non-low-income customers more frequently used their  
16 appliances during the peak hours of 3 - 7 PM. The only exception was the clothes  
17 washer; low-income customers responded with a 14% higher rate of using this  
18 appliance during peak hours.

19

20 Of the customers that made no adjustments to their thermostat behaviors during the  
21 winter period of the program, low-income customers responses indicated they were  
22 16% less likely than non-low-income customers to have their thermostat set to an  
23 energy efficient program. This group of low income customers were also 10% more  
24 likely to be setting their thermostats to a single temperature.

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1 Some of this disparity in thermostat behavior could be explained by the fact that  
2 the survey responses also found that, as a whole, low-income customers surveyed  
3 were 20% less likely to have a smart or programmable thermostat.

4

5 **Q30. What did low-income customers say about their desire to shift their usage?**

6 A30. Low-income customers, as a whole, had a desire to shift their usage. They were 1%  
7 - 5% more likely than non low-income customers to start all heating conservation  
8 and shifting actions like setting temperatures lower at peak usage times, setting a  
9 thermostat schedule while they sleep, opening/closing curtains to naturally warm  
10 their dwelling, closing the attic, basement, exterior doors and running ceiling fans  
11 at low speeds.

12

13 **Q31. What conclusions can be drawn from the survey results?**

14 A31. The surveys indicate that low-income customers have a desire to shift usage and  
15 are capable of shifting usage. This aligns with the Company's in-development  
16 outreach to existing D1.6 customers that will support the transition to D1.11.

17

18 Regression Analysis

19 **Q32. Are there any technical terms used in your analysis that may require**  
20 **explanation?**

21 A32. Yes. To aid in the understanding and to avoid confusion, I am defining the  
22 following terms that I will use in this section of my testimony:

23       ▪ Population Density: The number of persons per square mile by census tract.

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- 1           ▪   MiEJ Screen Composite Score: A composite score that “measures the
- 2                   relative environmental risk factors in communities”<sup>1</sup> at the census tract level
- 3                   created by Michigan’s Department of Environment, Great Lakes, and
- 4                   Energy (EGLE).
- 5           ▪   Multiple variable regression model: A linear regression model testing the
- 6                   relationship between one dependent and multiple independent variables.
- 7           ▪   P-Value: The result of a statistical significance test ranging from 0 to 1
- 8                   describing the likelihood of obtaining the observed data under the null
- 9                   hypothesis (i.e. no effect or difference). Results with a p-value of less than
- 10                  0.05 are considered statistically significant, meaning the results are likely
- 11                  not due to random chance.
- 12           ▪   R-Square: A coefficient of determination ranging from 0 to 1 which
- 13                   measures how well a regression model fits the data, indicating the
- 14                   proportion of variance in the dependent variable that can be explained by
- 15                   the independent variable(s) in the model. A value of 1 is considered a
- 16                   perfect fit.
- 17           ▪   Multicollinearity: When two or more of the independent variables in a
- 18                   multiple regression model are correlated with one another.
- 19           ▪   Variance Inflation Factor (VIF): A test to identify if there is
- 20                   multicollinearity in a regression model. A value of 1 is interpreted as no
- 21                   intercorrelation. There is no industry standard to evaluate moderate and
- 22                   high levels of intercorrelation. For the purposes of this study, I’ve adopted
- 23                   the recommendation of Penn State’s Eberly College of Science which is a

---

<sup>1</sup> [MiEJScreen Factsheet](https://www.michigan.gov/egle/-/media/Project/Websites/egle/Documents/Maps-Data/MiEJScreen/MiEJScreen-Factsheet.pdf), available at (<https://www.michigan.gov/egle/-/media/Project/Websites/egle/Documents/Maps-Data/MiEJScreen/MiEJScreen-Factsheet.pdf>) accessed on March 28, 2025.

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1 value exceeding 4 warrants further investigation and a value greater than 10  
2 indicates a serious sign of multicollinearity requiring correction.<sup>2</sup>

3

4 **Q33. What approach did you use to develop the regression analysis?**

5 A33. I conducted a multiple variable regression analysis using the percent difference in  
6 bills of a customer's D1.6 and D1.11 bill in 2022 as my dependent variable. The  
7 independent variables for the model were 2022 Usage in kWh, Population Density  
8 and the MiEJ Screen Composite Scores. Usage was at the customer level and the  
9 latter two were at the census tract level the customer resided in. The use of 2022  
10 data and bill differences is consistent with the bill impact analysis provided by the  
11 Company in Case No. U-21534 and the Commission's approval of the transition in  
12 that case.

13

14 **Q34. What were the datasets you used to perform your analysis?**

15 A34. I used several input datasets.

- 16 • The bill impact dataset Company Witness Willis prepared in Case No. U-  
17 21534 to identify a customer's 2022 Usage and the percentage difference in  
18 bills between D1.6 and D1.11 in 2022.
- 19 • The Census Bureau's Geocoder tool was used to identify the census tract a  
20 customer resides in.
- 21 • The American Community Survey (ACS) 5-year 2022 Michigan  
22 Demographic Data and Topologically Integrated Geographic Encoding and  
23 Referencing (TIGER) 2024 files at the census tract level were used to  
24 determine the census tracts Population Density.

---

<sup>2</sup> Penn State Eberly College of Sciences Applied Regression Analysis Course, available at <https://online.stat.psu.edu/stat462/node/180/> accessed on March 28, 2025.

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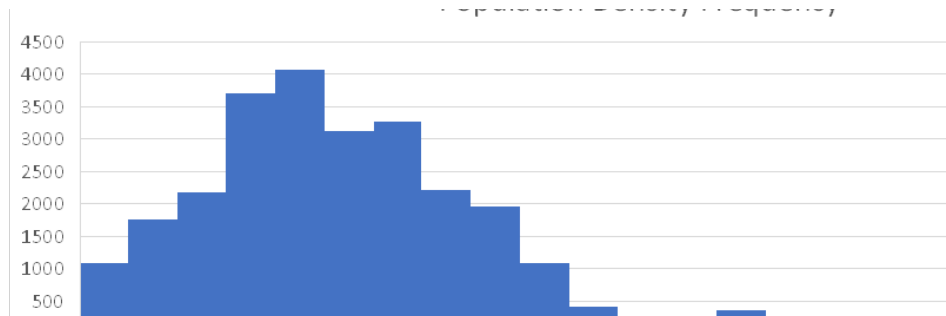
- Michigan's Department of Environment, Great Lakes and Energy (EGLE) MiEJ Screen Composite Scores at the census tract level were used.

**Q35. Did you modify the data prior to conducting the regressions?**

A35. Yes. I removed approximately 300 of the initial 26,175 records due to missing data, such as the Census Bureau's Geocoder not returning a census tract or lack of demographic data in the ACS 5-year survey.

Additionally, I excluded approximately 250 records to account for outliers in Population Density and 2022 Usage data. One example can be observed in Figure 1 below which is a histogram of the population density records showing that there are potential outliers in records that are greater than 16,000.

**Figure 1 : Histogram of population density records**



This observation is further confirmed when examining the records by their percentiles. The increase between the 99% to 100% percentile is three times the increase of the prior percentiles, an increase from 15,187 to 23,158, indicating records in the 99% - 100% could impact the results.

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1 **Q36. Is there anything you would like to note about this analysis?**

2 A36. Yes. The regression analysis I conducted is a retrospective study, comparing usage,  
3 population density and MiEJ scores of customers to their 2022 actual and modeled  
4 bills. Unlike the ACPP, for example, it does not include random sampling nor does  
5 it create new data; rather it utilizes existing data to identify the presence and  
6 significance of any correlations in the data.

7  
8 **Q37. What were the results of the multivariable regression model?**

9 A37. The model produced an overall p-value of 0 indicating statistical significance. The  
10 R-Square was 0.418904, meaning that the regression equation explains  
11 approximately 41.9% of the variance in data. The p-value results for individual  
12 variables in the model were all less than 0.05, indicating they all are statistically  
13 significant predictors for a customer's modeled percent bill difference between  
14 D1.6 and D1.11 in 2022.

| <i>Variable</i>      | <i>P-value</i> |
|----------------------|----------------|
| Population Density   | 4.99794E-11    |
| MiEJ Composite Score | 0              |
| 2022 Usage           | 0              |

15  
16  
17 Calculating the VIF scores<sup>3</sup> to check for multicollinearity between the variables the  
18 values are near 1 indicating little intercorrelation between our independent  
19 variables affecting the results.

---

<sup>3</sup> Variance Inflation Factor a test to identify if there is multicollinearity in a regression model.



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| <i>Variable</i>      | <i>VIF Score</i> |
|----------------------|------------------|
| Population Density   | 1.1073           |
| MiEJ Composite Score | 1.1097           |
| 2022 Usage           | 1.0037           |

1

2

The linear coefficients of the model indicate negative correlations between a customer's 2022 Annual Usage and the MiEJ Screen Composite Score of their census tract.

4

5

| <i>Variable</i>      | <i>Coefficient</i> |
|----------------------|--------------------|
| Population Density   | 0.0000001          |
| MiEJ Composite Score | -0.0000993         |
| 2022 Usage           | -0.0000012         |

6

**Q38. What conclusions, if any, did you draw from this analysis?**

8

A38. The average D1.6 customer represented in the 2022 data, would be expected to have a 0.17% lower bill on D1.11. However, the independent variables do not fully predict a customer's percentage bill change between D1.6 and D1.11 in 2022 – the model accounts for 41.9% of the variance. Moreover, while the results highlight a correlation between the independent and dependent variables, the independent variables impact is small - 1 percentile increases to variables lead to <0.1% changes in the customer bill.

15

16

Among the variables tested, a customer's 2022 usage had the largest impact on the percentage change in a customer's bill when comparing D1.6 and D1.11. Holding constant the other two variables, Population Density and MiEJ Screen Score, a one percentile increase in 2022 usage corresponds to bill reduction of 0.029% when

17

18

19

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1 moving from D1.6 to D1.11. Using the average monthly 2022 D1.6 bill of \$134.91,  
2 this effect translates to an \$0.04 in bill savings. MiEJ Screen Score has a 0.008%  
3 decrease and Population Density has a 0.001% increase for every one percentile  
4 increase in their respective variables.

5

6 Customers did not need to have above average usage in order to have a lower bill  
7 on D1.11. Again, first holding the other two variables constant at their median  
8 values of a population density of approximately 5,000 persons per square mile and  
9 a MiEJ Composite Score of 89 then a yearly usage of higher than 6,000 kWh in  
10 2022 corresponded to a lower bill on D1.11, which is lower than the median value  
11 of 7,250 kWh.

12

13 **Q39. Does this conclude your testimony?**

14 A39. Yes.

**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-21860

QUALIFICATIONS  
  
AND  
  
DIRECT TESTIMONY  
  
OF  
  
ANTHONY L. TURNER

**DTE ELECTRIC COMPANY**  
**QUALIFICATIONS AND DIRECT TESTIMONY OF ANTHONY L. TURNER**

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

2       A1.    My name is Anthony L. Turner (he/him/his), One Energy Plaza, Detroit,  
3               Michigan 48226. I am employed by DTE Energy Corporate Services LLC, a  
4               subsidiary of DTE Energy Company (DTE Energy), within Regulatory Affairs  
5               as a Senior Strategist.

6

7       **Q2.    On whose behalf are you testifying?**

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

9

10      **Q3.    What is your educational background?**

11      A3.    I graduated from Wayne State University with a Bachelor of Science in Business  
12               Administration with a concentration in Finance.

13

14      **Q4.    What is your work experience?**

15      A4.    I have been employed by DTE Energy since 2015 and have occupied several  
16               different positions of increasing responsibility. I started in the Customer Service  
17               organization with a focus on providing billing support to small-medium business  
18               customers to resolve and troubleshoot billing irregularities. In 2017, I  
19               transitioned to the System Compliance group and was responsible for executing  
20               monthly Sarbanes Oxley (SOX) controls on the billing system to ensure  
21               compliance with the Company's billing rules set forth by the Michigan Public  
22               Service Commission (MPSC or Commission). In 2019, I was promoted to Senior  
23               Analyst in System Management. In this role, I provided rate case implementation  
24               support as well as support to the overall Customer Service IT Portfolio. Most  
25               recently, in 2024, I joined Regulatory Affairs as a Senior Strategist.

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1       **Q5.    What are your current duties and responsibilities?**

2       A5.   My current responsibilities include the development and administration of  
3           Company tariffs, rules, and regulations. I am also responsible for developing and  
4           recommending pricing and rate design policy for commercial and industrial rates  
5           and providing regulatory support to other business units.

6

7       **Q6.    Have you completed any seminars or other training courses?**

8       A6.   Yes. I attended the Edison Electric Institute (EEI) Electric Rates Course: Rates  
9           in a Changing Industry in July 2024.

10

11       **Q7.    Have you previously sponsored testimony before the Michigan Public**  
12           **Service Commission?**

13       A7.   Yes, I have sponsored testimony for Case No. U-21643 (Outage Credit Waiver).

Line  
No.

1 **Purpose of Testimony**

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

3 A8. The purpose of my testimony is to address:

- 4 • **Rate Design:** Support the proposed rate design and language modifications  
5 for the Company's rate schedules:
- 6 ○ *Commercial secondary:* (1) The development of capacity and non-capacity  
7 charges for each commercial secondary rate schedule based on the cost of  
8 service supported by Company Witness Cejas Goyanes; and (2) design of  
9 distribution rates for all commercial secondary rate schedules.
- 10 ○ *Primary:* (1) The development of capacity and non-capacity charges for  
11 each primary rate schedule based on the cost of service supported by  
12 Company Witness Cejas Goyanes; (2) design of distribution rates for all  
13 primary rate schedules; and (3) development of power supply rates for Rate  
14 Schedule D13.
- 15 ○ *Commercial and Industrial Rate Tariff Changes:* (1) Amendments to the  
16 tariff as it relates to Rate Schedules D3.11 and D14; and (2) updates to the  
17 power supply capacity language for applicable rates and riders.

18

19 **Q9. Are you sponsoring any exhibits in this proceeding?**

20 A9. Yes. I am supporting the following exhibits:

| 21 | <u>Exhibit</u> | <u>Schedule</u> | <u>Description</u>                               |
|----|----------------|-----------------|--------------------------------------------------|
| 22 | A-16           | F3              | Present and Proposed Revenues by Rate Schedule – |
| 23 |                |                 | 12 months ending December 31, 2026               |
| 24 | A-16           | F4              | Comparison of Present and Proposed Monthly Bills |
| 25 |                |                 | – 12 months ending December 31, 2026             |

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1           A-16       F5           Calculation of Voltage Level Distribution Charges

2           A-16       F8           Proposed Tariff Sheets

3

4           With regard to Exhibit A-16, Schedule F3, I am sponsoring pages 12-45,  
5           Company Witness Willis is sponsoring pages 1-11, and Company Witness  
6           Hartley is sponsoring the remaining sheets contained in the exhibit. With regard  
7           to Exhibit A-16 Schedule F4, I am sponsoring pages 22-60 and Company  
8           Witness Willis is sponsoring pages 1-21.

9

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

11       A10. Yes, they were.

12

13       **Rate Design**

14       **Q11. What does Exhibit A-16, Schedule F3 show?**

15       A11. This exhibit presents the current and proposed rate design along with the  
16       corresponding revenue by rate schedule based on the billing determinants for the  
17       12-month period ending December 31, 2026. The various billing components  
18       are listed in column (a), and the respective billing determinants, including units  
19       of measure, are listed in column (b). These billing determinants were developed  
20       based on historical data and relationships, as well as known and measurable  
21       changes, and are consistent with Company Witness Leuker's sales forecast. The  
22       existing rates, as approved by the MPSC's Order in Case No. U-21534 on  
23       January 23, 2025, are in column (c), and are used to calculate the present  
24       revenues in column (d). The rates proposed in this proceeding are in column (e),  
25       with the resulting revenues in column (f).

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1 The only exceptions to the above structure are on pages 21 and 36-37 of Exhibit A-  
2 16, Schedule F3. These pages contain the rate designs for the Company's  
3 commercial and primary time of use rates approved in the last general rate case, U-  
4 21534. Page 21 contains the rate design for commercial time of use Rate Schedule  
5 D3.11 (designed revenue neutral to Rate Schedule D3). Pages 36-37 contain the  
6 rate design for primary time of use Rate Schedule D14 (designed revenue neutral  
7 to Rate Schedule D11). For these pages of Exhibit A-16 Schedule F3, column (d)  
8 shows the proposed revenue of the corresponding revenue neutral rate, Rate  
9 Schedules D3 and D11 respectively. Column (e) contains the proposed rates for  
10 Rate Schedules D3.11 and D14, with the resulting revenues in column (f). A  
11 comparison of the totals in columns (d) and (f) on these pages show the rate  
12 schedules are designed to be revenue neutral to the proposed D3 and D11 Rate  
13 Schedules, respectively.

14

15 **Q12. Are there any changes to rate design which apply to both commercial**  
16 **secondary and primary rates?**

17 A12. Yes. In its December 1, 2023, Order in Case No. U-21297, the Commission  
18 directed the Company to maintain the current ratio between power supply  
19 demand and energy rates for Rate Schedules D4, D6.2 and D11. The  
20 Commission's Order stated, "*that the current ratio between demand and energy*  
21 *charges for Rate Schedules D4, D6.2, and D11 should be maintained...*"<sup>1</sup>

22

23 The approach was intended to mitigate the impacts of volatility in the capacity  
24 and non-capacity allocations and the resulting volatility in the overall ratio of

---

<sup>1</sup> December 1, 2023 Order in Case No. U-21297, Pg 328.



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1 demand and energy-based rates. The ratio considers total power supply revenues  
2 (i.e., both capacity and non-capacity revenues).

3  
4 Power supply capacity revenue has historically been collected entirely through  
5 demand charges on these rate schedules, however the capacity revenue  
6 requirements for these rate schedules in the instant case exceeded the current  
7 demand share of the present demand to energy ratios. Using Rate Schedule D4  
8 as an example, though the concept applies equally to Rate Schedules D11 and  
9 D6.2:

- 10 • The capacity portion of the production revenue requirement in the instant  
11 case is 64%.
- 12 • The current demand/energy split for Rate Schedule D4, using present  
13 revenue, is 53% demand and 47% energy.
- 14 • Historically, all Rate Schedule D4 capacity costs have been recovered  
15 through demand charges, however in this case the capacity allocations  
16 exceed the present demand ratio. Aligning the two constraints (allocations  
17 and demand ratio) requires either:
  - 18 1. A portion of the capacity costs be recovered on a volumetric basis, or
  - 19 2. A negative non-capacity demand charge.

20 The Company is proposing in this case that a portion of the capacity costs be  
21 recovered on a volumetric basis on the relevant rate schedules. This approach is  
22 more appropriate than negative rates and maintains alignment with the  
23 allocations of capacity and non-capacity costs and also maintains designing  
24 power supply rates such that the present ratio recovered via demand versus  
25 energy rates is held constant which aligns with the rate design methodology

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1 established in Case No. U-21297 (and again used in the approved rate design in  
2 Case No. U-21534).

3

4 **Commercial Secondary Rate Design**

5 **Q13. Can you please provide a brief description of each of the Company's**  
6 **commercial secondary rate schedules?**

7 A13. Yes, the following descriptions are in the order shown in Exhibit A-16, Schedule  
8 F3.

- 9 • Rate Schedule D1.1 is a separately metered interruptible space conditioning  
10 service rate.
- 11 • Rate Schedule D1.7 is a separately metered rate available for supplemental  
12 geothermal electric service with rates dependent on season and time of day.
- 13 • Rate Schedule D1.8 is a dynamic peak pricing product with three time of  
14 day pricing periods and is periodically subject to critical peak pricing.
- 15 • Rate Schedule D1.9 is a separately metered product for service to charge  
16 electric vehicles.
- 17 • Rate Schedule D3 is the Company's general service rate for non-residential  
18 customers.
- 19 • Rate Schedule D3.1 is an unmetered general service rate available to  
20 customers for loads which are impractical to meter.
- 21 • Rate Schedule D3.2 is a secondary educational rate available for school,  
22 college, or university customer locations.
- 23 • Rate Schedule D3.3 is available to customers desiring interruptible service.
- 24 • Rate Schedule D3.5 is a Company owned charging service and includes  
25 on/off peak non-capacity energy charges and a session fee.

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- 1 • Rate Schedule D3.11 is an optional time of use rate with rates that vary
- 2 depending on season and time of day and was approved in Case No. U-
- 3 21534; it will be available to customers no later than June 1, 2025.
- 4 • Rate Schedule D4 is the Company's large general service rate and includes
- 5 a demand charge.
- 6 • Rate Schedule D5 is an interruptible electric water heating rate available to
- 7 commercial customers based on certain size criteria.
- 8 • Rate Schedule E1.1 is for any metered energy provided to municipality-
- 9 owned streetlights.
- 10 • Rate Schedule Rider 7 is available to customers with high intensity lighting
- 11 requirements, such as greenhouses.
- 12 • Finally, Rate Schedule Rider 8 is available to customers with total electric
- 13 commercial space conditioning needs.

14

15 **Q14. What is the basis for the Company's proposed commercial secondary rates**  
16 **in this proceeding?**

17 A14. The proposed commercial secondary power supply and distribution charges  
18 were designed to meet their respective deficiencies shown in Company Witness  
19 Cejas Goyanes' Exhibit A-16, Schedule F1.1, page 2 (for power supply) and  
20 Exhibit A-16, Schedule F1.2, page 1 (for distribution). The proposed power  
21 supply capacity and non-capacity rates were designed to recover the revenues  
22 pursuant to Company Witness Cejas Goyanes' Exhibit A-16, Schedule F1.5,  
23 which shows how much of the power supply revenue requirement for each rate  
24 class is related to capacity and non-capacity costs.

Line  
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1       **Q15. How are the power supply revenue targets allocated in your rate design?**

2       A15. I followed the same methodology utilized in Case No. U-21534 to allocate both  
3           the capacity and non-capacity power supply revenue requirements to the  
4           individual tariffs within the secondary class. In his cost-of-service analysis,  
5           Company Witness Cejas Goyanes identifies three separate cost classes: one  
6           specific to Rate Schedule D3.2, one specific to Rate Schedule D4, and one to  
7           capture Rate Schedule D3 and all remaining rate schedules. The revenue  
8           requirements for D3.2 and D4 are assigned directly to the respective class. The  
9           revenue requirement for the D3 and other subgroup is further allocated based on  
10          each tariff's percentage contribution to the total present power supply revenue  
11          for that same subgroup.

12

13       **Q16. How were the commercial secondary energy rates determined?**

14       A16. With the exception of rate schedules D3.5 and D4, all commercial secondary  
15          power supply rates are energy based. After allocating the revenue targets to each  
16          individual rate schedule as discussed earlier, I used the capacity and non-  
17          capacity targets for each rate schedule to determine the capacity and non-  
18          capacity energy rates, respectively. The rate structure for Rate Schedule D3.5  
19          has a non-capacity energy charge based on time of use and a session fee which  
20          includes power supply capacity and is based on the demand rating of the  
21          charging station consistent with the approved rate design in Case No. U-21534.  
22          Consistent with Case Nos. U-21297 and U-21534, the rate structure for Rate  
23          Schedule D4 was designed to maintain the existing ratio between demand and  
24          energy charges. For Rate Schedule D4 the current relationship for power supply  
25          charges is 53% demand and 47% energy. While the capacity revenue

Line  
No.

1 requirement has historically been collected entirely as a demand charge, the  
2 power supply capacity requirement outlined by Witness Cejas Goyanes exceeds  
3 the current demand share of the demand to energy ratio. Consequently, the power  
4 supply capacity revenue requirement was designed to be recovered as a demand  
5 charge to the fullest extent possible without disrupting the relationship between  
6 demand and energy. The remaining capacity requirement is designed as two  
7 energy-based rates which mirror the current non-capacity energy charges in  
8 structure. Given the demand share of the demand to energy ratio is entirely  
9 accounted for by the capacity rates, the non-capacity revenue requirement is  
10 recovered using two energy-based rates, dependent on the total hours use of  
11 demand. This approach is applied to maintain the balance between demand and  
12 energy charges, which is consistent with the approved rate design methodology  
13 used in Case Nos. U-21297 and U-21534.

14

15 **Q17. How does Company Witness Cejas Goyanes' revenue deficiency/sufficiency**  
16 **for distribution presented in this instant case impact your rate design?**

17 A17. My rate design in this instant case is consistent with the rate design methodology  
18 used by the MPSC Staff to calculate rates which were approved by the  
19 Commission in Case Nos. U-18014, U-18255, U-20105, U-20162, U-20561, U-  
20 20836, U-21297, and most recently, U-21534. In each of these cases, both the  
21 Company and MPSC Staff maintained the position that if the customers are  
22 similar enough to be classified together, their distribution rates should also be  
23 similar to the extent possible.

Line  
No.

1      **Q18. Are you proposing changes to the secondary service charges in this case?**

2      A18. No.

3

4      **Primary Rate Design**

5      **Q19. Can you please provide a brief description of each of the Company's**  
6      **primary customer rate schedules?**

7      A19. Yes, the Company offers several primary rates.

- 8              • Rate Schedule D11 is the Company's main primary rate schedule and is  
9              available to customers served at primary, sub-transmission, or transmission  
10             voltage.
- 11             • Rate Schedule D6.2 is available to educational institution customer  
12             locations (schools, colleges, or universities) desiring service at primary,  
13             sub-transmission, or transmission voltage.
- 14             • Rate Schedule D8 is the Company's primary voltage interruptible rate  
15             which is limited to 300 megawatts.
- 16             • Rate Schedule D10 is the Company's all-electric school building rate  
17             (including electric space and water heating).
- 18             • Rate Schedule D12 is the Company's Experimental Large Customer Low  
19             Peak Demand Supply rate.
- 20             • Rate Schedule D13 is the Company's XL Large Industrial Rate.
- 21             • Rate Schedule D14 is an optional time of use rate with power supply rates  
22             that vary depending on season and time of day and was approved in Cas No.  
23             U-21534; it will be available to customers no later than December 31, 2025.

Line  
No.

- 1           • Riders 1.1 and 1.2 are specific interruptible rates for customers operating
- 2           electric furnaces for metal melting (Rider 1.1) or using electric heat as an
- 3           integral part of manufacturing (Rider 1.2).
- 4           • The Company's Rider 3 rate provides standby service for various customers
- 5           with generation facilities operating in parallel with the Company's system.
- 6           • Rider 10 is an interruptible supply rate available to customers with larger
- 7           interruptible loads.

8

9           **Q20. How were the capacity and non-capacity charges determined for the**  
10           **primary rate schedules?**

11          A20. My proposed primary rate designs result in power supply rates which are set  
12          equal to cost-to-serve. Company Witness Cejas Goyanes determined the  
13          capacity and non-capacity revenue requirements for each cost-of-service class,  
14          which are shown in his Exhibit A-16, Schedule F1.5.

15

16          For primary rates with billing demand components, capacity rates were designed  
17          to collect the total capacity revenue requirement through the billing demand  
18          charges to the extent that they did not disrupt the rates' current demand to energy  
19          ratio. Where the capacity revenue requirement exceeded the demand share of the  
20          demand to energy ratio, an energy charge was used to collect the remaining  
21          capacity revenue requirement. For primary rates that do not have billing demand  
22          components, capacity rates were designed to collect the capacity revenue  
23          requirement through energy charges. Generally, non-capacity rates were  
24          designed to recover the non-capacity revenue requirement through energy and/or

Line  
No.

1 demand charges. Rate Schedule D14 collects its capacity and non-capacity  
2 revenue through seasonal, time varying, energy-based charges.

3

4 **Q21. Did the Commission provide direction on Rate Schedule D14 rate design in**  
5 **Case No. U-21534?**

6 A21. Yes. In its January 23, 2025 Order in Case No. U-21534, the Commission  
7 directed the Company to propose a modification to Rate Schedule D14 with an  
8 on-peak window of time that is sufficiently shorter than eight hours following  
9 consultation with interested parties. The Company met with interested parties on  
10 March 18, 2025, and is including a proposal for a revised D14 on-peak period in  
11 this case, consistent with the January 23, 2025 Order.

12

13 **Q22. What are the proposed power supply time of use pricing periods for D14?**

14 A22. There are two elements to the D14 time of use pricing – the seasonal variation  
15 and the on-peak period. The Company is not proposing any change to the  
16 seasonality of the rate. The Company is proposing an updated on-peak period of  
17 1:00 – 6:00pm weekdays, excluding holidays, compared to the existing D14  
18 11:00 am – 7:00 pm, excluding holidays, on-peak period. The on-peak hours  
19 remain constant across the year to support customer understanding and to  
20 maintain simplicity in the Company's rates.

21

- Season

22

- Summer pricing in effect June – September

23

- Non-summer pricing in effect from October – May

24

- Time of day



Line  
No.

- 1                           ○ On-peak from 1:00pm – 6:00pm, Monday – Friday, excluding
- 2                           holidays
- 3                           ○ Off-peak in all other hours
- 4

5       **Q23. What is the basis for the 1:00 – 6:00pm on-peak period?**

6       A23. On page 430 of the January 23, 2025, Order in Case No. U-21534, the  
 7       Commission directed the Company to “*propose in its next rate case a revenue-*  
 8       *neutral rate with an on-peak window of time that is shorter than eight hours and*  
 9       *that is based on both system peak and class peak, consistent with the method*  
 10       *used to develop the on-peak window for the residential and commercial TOU*  
 11       *rates*”. The Company compiled and analyzed system and primary class peak  
 12       hour count data from the period of 2020-2024 to develop the proposed on-peak  
 13       period. The proposed on-peak period of 1:00pm-6:00pm aligns with both the  
 14       system coincident peaks during the summer months<sup>1</sup> as well as the primary class  
 15       peaks in the summer months. Considering the 2020 – 2024 period, all the  
 16       summer system peaks considered occurred within the proposed on-peak hours,  
 17       and 18 of the 20 summer primary class peaks occurred within the on-peak period.  
 18       This alignment ensures the on-peak period reflects the periods of highest use on  
 19       the system and the highest system use of this customer group.

20

21       **Q24. How did you develop the determinants and the power supply pricing**  
 22       **differential between the peak periods and the seasons?**

23       A24. I allocated determinants to each pricing period based on (1) historic D11 actuals  
 24       and (2) an assumed on-peak to off-peak shift of 8.2% for the summer months

---

<sup>1</sup> June, July, August, September.

Line  
No.

1 and 3.3% for the non-summer months. This shift is consistent with the D3.11  
2 shift proposed by the Company in Case No. U-21534 and approved by the  
3 Commission in its January 23, 2025 Order. For power supply pricing  
4 differentials, I utilized the relative difference in LMP for the years 2021-2023  
5 between the periods and seasons. This is consistent with the method approved  
6 by the Commission for Rate Schedules D3.11 and D1.11, which varies power  
7 supply costs using the relative difference in LMP.

8  
9 **Q25. How were the Distribution charges determined for the primary rate**  
10 **schedules?**

11 A25. The Company's proposed primary delivery rates are cost based by voltage level,  
12 utilizing the distribution base revenue deficiency/sufficiency levels by voltage  
13 class shown in Exhibit A-16, Schedule F1.2 and sponsored by Company Witness  
14 Cejas Goyanes. Exhibit A-16, Schedule F5 shows the development of the  
15 voltage level Distribution Demand Charges for the primary tariffs.

16  
17 The present (U-21534 Base Rates) base delivery revenue by voltage level for  
18 each rate schedule is shown in column (a). The base delivery revenue includes  
19 all revenues from service charges, distribution energy and demand charges, and  
20 substation credits. The cost-based deficiency/sufficiency for each service  
21 voltage level, from Exhibit A-16, Schedule F1.2, sponsored by Company  
22 Witness Cejas Goyanes, are shown in column (b). Column (c) shows the total  
23 proposed base delivery revenue to be collected from each voltage level, which  
24 is the sum of columns (a) and (b).

Line  
No.

1 Columns (d) and (e) show the proposed service charge revenue and substation  
2 credits. Columns (d) and (e) are subtracted from column (c) to determine the  
3 amount of base delivery revenue to be collected in distribution demand charges,  
4 shown in column (f). The distribution demand revenue in column (f) is then  
5 divided by the distribution demands in column (g) to determine the distribution  
6 demand charges by voltage level, as shown in column (h).

7

8 **Q26. Will all primary customers pay the same \$/kW distribution charges (i.e., an**  
9 **equivalent amount as shown in column (h))?**

10 A26. All primary rates will have the same \$/kW charges shown in column (h) with the  
11 exception of Rate Schedule D10 and riders R1.1 and R1.2, which have energy-  
12 based delivery charges. For Rate Schedule D10 and riders R1.1 and R1.2, I have  
13 calculated energy charges equivalent to the proposed voltage level distribution  
14 charges. Additionally, Rate Schedule D13 is a primary rate schedule with  
15 energy-based delivery charges and is discussed below.

16

17 **Q27. How is Rate Schedule D12 designed?**

18 A27. Rate Schedule D12 is designed to have increases consistent with Rate Schedule  
19 D11. Given that there are no present or forecasted sales on D12, this method is  
20 considered appropriate. The power supply rates for D12 are increased at the  
21 same percentage increase as those for D11. Additionally, the distribution rates  
22 are consistent with the voltage level rates applicable to all primary service  
23 customers.

Line  
No.

1       **Q28. How is Rate Schedule D13 designed?**

2       A28. The proposed design is consistent with the approved design in Case No. U-21534  
3           and utilizes Blue Water Energy Center (BWEC) as a proxy indication of  
4           marginal cost to serve. The proposed capacity rates maintain the levelized cost  
5           of BWEC capacity approved by the Commission in successive cases, including  
6           Case No. U-21534, and remain unchanged.

7  
8           The proposed non-capacity rates utilize BWEC proxy costs based on a fixed heat  
9           rate assumption, which is unchanged from Case No. U-21534, forecasted natural  
10          gas costs as described in the Company's direct testimony and exhibits in Case  
11          No. U-21594<sup>1</sup>, and a non-fuel O&M assumption. Proposed transmission rates  
12          reflect the incremental cost of transmission to the Company resulting from  
13          projected D13 load.

14  
15          The proposed administrative charge reflects the incremental cost to administer  
16          the Rate Schedule and is unchanged. Distribution rates are consistent with the  
17          voltage level distribution rates for primary, sub transmission, and transmission  
18          voltage. Distribution rates are designed as volumetric, assuming a 75% load  
19          factor. The customer charge is consistent with those proposed for all primary  
20          customers.

21

22       **Q29. Are you proposing changes to the primary rate service charges?**

23       A29. No.

---

<sup>1</sup> Case No. U-21594, Exhibit A-14, CY 2026.

Line  
No.

1       **Q30. Are you proposing any new primary rate schedules?**

2       A30. No.

3

4       **Q31. What does Exhibit A-16, Schedule F4 show?**

5       A31. This exhibit provides a comparison of typical monthly bills by rate schedule  
6           based on current and proposed rates. For each rate schedule, the exhibit  
7           calculates the bill amounts under existing rates and proposed rates across a broad  
8           range of consumption levels. The differences between these amounts illustrate  
9           the impact of the proposed rate changes. I sponsor pages 22-60 of this exhibit  
10          which cover rate schedules for which I designed the Company's proposed rates.

11

12       **Q32. What does Exhibit A-16, Schedule F8 show?**

13       A32. This exhibit presents the proposed rate and tariff sheet changes resulting from  
14          the pricing adjustments and proposals described earlier in my testimony, as well  
15          as additional proposals described below.

16

17       **Commercial and Industrial Rate Tariff Changes**

18       **Q33. Are you sponsoring any new tariff sheets?**

19       A33. No.

20

21       **Q34. Are you proposing any changes to the primary tariff language?**

22       A34. Yes. As described in my testimony, I am proposing the following changes to the  
23          primary tariff language:

- 24               • An update to the pricing periods for the on and off-peak hours for Rate  
25               Schedule D14.

Line  
No.

- 1 • An addition of capacity energy charge language for applicable rate
- 2 schedules D11, D6.2, D8, and Rider 3.

3

4 **Q35. Are you proposing any other changes to the primary tariff language?**

5 A35. Yes. I am proposing to incorporate Rate Schedule D14 into the existing  
6 applicability language for Rider 1.1, Rider 1.2, and Rider 3. This is consistent  
7 with Rate Schedule D11 and was inadvertently left out of the Company's initial  
8 tariff filing in Case No. U-21534. I am also proposing to add the following  
9 sentence to the availability of Rate Schedule D14, which similarly was  
10 inadvertently left out of the Company's initial tariff filing.

- 11 ○ *"This rate is not available for service in conjunction with the Primary*
- 12 *Supply Rate".*

13

14 **Q36. Are you proposing any changes to the commercial secondary tariff**  
15 **language?**

16 A36. Yes. I am proposing to incorporate Rate Schedule D3.11 into existing  
17 applicability language for Rider 1.1, Rider 1.2, Rider 3, Rider 7, and Rider 8.  
18 This is consistent with Rate Schedule D3 and was inadvertently left out of the  
19 Company's initial tariff filing in Case No. U-21534. I am also proposing  
20 language for capacity energy charges to be added to Rate Schedule D4 as  
21 described earlier in my testimony.

22

23 **Q37. Are you proposing any other changes to the Company's rate book?**

24 A37. Yes. I am proposing the below language to be added to the availability of Rate  
25 Schedule D3.11. This language is consistent with existing language in Rate

Line  
No.

1 Schedule D3 availability and was inadvertently left out of the Company's initial  
2 tariff filing in Case No. U-21534.

3 • "This rate is not available for service in conjunction with *the General*  
4 *Service Rate or* Large General Service Rate except when used exclusively  
5 to serve electric vehicle service equipment."

6 • "*This rate is not available to customers desiring service through one meter*  
7 *for residential purposes to a single or double occupancy dwelling unit.*"

8

9 **Q38. Does this conclude your testimony?**

10 A38. Yes.

**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-21860

QUALIFICATIONS  
  
AND  
  
DIRECT TESTIMONY  
  
OF  
  
KIRK M. VANGILDER



**DTE ELECTRIC COMPANY**  
**QUALIFICATIONS AND DIRECT TESTIMONY OF KIRK M. VANGILDER**

Line  
No.

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

2   A1.   My name is Kirk M. Vangilder (he/him/his). My business address is One Energy  
3           Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate  
4           Services, LLC, a subsidiary of DTE Energy Company (DTE Energy), within the  
5           Regulatory Affairs organization as a Principal Financial Analyst for Revenue  
6           Requirements.

7  
8   **Q2.   On whose behalf are you testifying?**

9   A2.   I am testifying on behalf of DTE Electric Company (DTE Electric or Company).  
10

11   **Q3.   What is your educational background?**

12   A3.   I received a Bachelor of Arts Degree in Accounting from Michigan State  
13           University's Eli Broad College of Business in 2004 and a Master of Science Degree  
14           in Accounting from Michigan State University's Eli Broad Graduate School of  
15           Management in 2006.  
16

17   **Q4.   Have you completed any seminars or other training courses?**

18   A4.   Yes, I have. I completed a utility finance and ratemaking course taught by Excidian,  
19           LLC. Additionally, I attended trainings hosted by Electric Utility Consultants, Inc,  
20           (EUCI) on utility cost of service and ratemaking. I also completed the ratemaking  
21           program conducted by the Institute of Public Utilities at Michigan State University.  
22

23   **Q5.   What is your work experience?**

24   A5.   From 2006 to 2011, I practiced public accounting with the international accounting  
25           firm Grant Thornton LLP where I had positions of increasing responsibility.

Line  
No.

1 During this time, I received my Certified Public Accountant license. In October  
2 2011, I joined DTE Energy as a Financial Auditor in the Audit Services department.  
3 In March 2013 I was promoted to Senior Financial Auditor, where I performed  
4 substantive testing and controls testing to support DTE Energy's financial  
5 statement audits and regulatory filings process. In August 2014, I accepted a  
6 position within DTE Energy's Controllers organization as a Senior Business  
7 Financial Analyst with responsibility for various accounting, budgeting, and  
8 reporting activities for DTE Gas, including financial and revenue requirement  
9 modeling. In 2018, I transferred to Regulatory Affairs as a Senior Rate Analyst in  
10 their Revenue Requirements group, and in 2019 I was promoted to my current  
11 position as Principal Financial Analyst.

12

13 **Q6. Do you hold any certifications or are you a member of any professional**  
14 **organizations?**

15 A6. I received my Certified Public Accountant license in 2008 and I am currently a  
16 registered accountant within the State of Michigan.

17

18 **Q7. What are your current duties and responsibilities?**

19 A7. As a Principal Financial Analyst for Revenue Requirements within DTE Energy's  
20 Regulatory Affairs organization, I am responsible for revenue requirement studies  
21 for regulatory filings, regulatory analysis and research, and for supporting certain  
22 MPSC filings, such as general rate cases.

23

24 **Q8. Have you previously sponsored testimony before the Michigan Public Service**  
25 **Commission (MPSC or Commission)?**

Line  
No.

- 1     A8.     Yes, I have. I have sponsored testimony in the following cases:
- 2             U-20373         DTE Electric 2020-2021 EWR Plan
- 3             U-20373-A     DTE Electric 2020-2021 Amended EWR Plan
- 4             U-20429         DTE Gas 2020-2021 EWR Plan
- 5             U-20642         DTE Gas 2019 Main Rate Case
- 6             U-20703         DTE Electric 2019 EWR Reconciliation
- 7             U-20708         DTE Gas 2019 EWR Reconciliation
- 8             U-20711         DTE Electric 2019 PLD/TRM Reconciliation
- 9             U-20836         DTE Electric 2022 General Rate Case
- 10            U-20876         DTE Electric 2022-2023 EWR Plan
- 11            U-20881         DTE Gas 2022-2023 EWR Plan
- 12            U-20940         DTE Gas 2021 General Rate Case
- 13            U-20987         DTE Electric 2020 PLD/TRM Reconciliation
- 14            U-21206         DTE Electric & DTE Gas 2021 EWR Reconciliation
- 15            U-21242         DTE Electric 2021 Demand Response Reconciliation
- 16            U-21291         DTE Gas 2024 General Rate Case
- 17            U-21297         DTE Electric 2023 General Rate Case
- 18            U-21307         DTE Electric 2021 & 2022 PLD/TRM Reconciliations
- 19            U-21313         DTE Electric & DTE Gas 2022 EWR Reconciliation
- 20            U-21403         DTE Electric 2022 Demand Response Reconciliation
- 21            U-21534         DTE Electric 2024 General Rate Case
- 22            U-21658         DTE Electric 2023 Demand Response Reconciliation
- 23            U-21662         DTE Electric 2024 Amended REP Plan
- 24            U-21845         DTE Electric 2024 IRM Reconciliation

Line  
No.

1 **Purpose of Testimony**

2 **Q9. What is the purpose of your testimony in this proceeding?**

3 A9. I am providing testimony related to the historical and the projected sections of this  
4 rate case filing. In Section A – Historical Test Period, I am supporting DTE  
5 Electric's historical revenue deficiency for the twelve months ended December 31,  
6 2023. In preparing my rate case exhibits, I relied on financial information supplied  
7 by Company Witnesses Uzenski and Lepczyk. I am sponsoring the derivation of  
8 the historical overall rate of return, Net Operating Income (NOI) adjustments for  
9 interest synchronization and income tax savings, and the revenue conversion factor.

10

11 In Section B – Projected Test Period, I am sponsoring DTE Electric's projected  
12 revenue deficiency for the twelve months ending December 31, 2026, as well as the  
13 derivation of the projected overall rate of return, the NOI adjustments for interest  
14 synchronization and income tax savings, and the projected revenue conversion  
15 factor. I also calculate the incremental revenue requirement for DTE Electric's  
16 Tree Trim Regulatory Asset, and the return on DTE Electric's Monroe Regulatory  
17 Asset. Lastly, I am supporting the calculation of the incremental revenue  
18 requirements for DTE Electric's Infrastructure Recovery Mechanism (IRM) and  
19 DTE Electric's alternative IRM proposal.

20

21 **Q10. Are you sponsoring any exhibits in this proceeding?**

22 A10. Yes. I am supporting the following historical and projected exhibits:

23 Section A – Historical Test Period Ended December 31, 2023

24 Exhibit              Schedule              Description

25 A-1                      A1                      Historical Revenue Deficiency (Sufficiency)

Line  
No.

|    |                                                            |                 |                                                 |
|----|------------------------------------------------------------|-----------------|-------------------------------------------------|
| 1  | A-2                                                        | B1              | Historical Rate Base                            |
| 2  | A-3                                                        | C2              | Historical Revenue Conversion Factor            |
| 3  | A-3                                                        | C12             | Historical Tax Effect of Interest Allowed in    |
| 4  |                                                            |                 | Ratemaking Formula                              |
| 5  | A-3                                                        | C13             | Historical Tax Effect of Interest               |
| 6  |                                                            |                 | Synchronization Adjustment                      |
| 7  | A-4                                                        | D1              | Historical Rate of Return Summary               |
| 8  |                                                            |                 |                                                 |
| 9  | Section B – Projected Test Period Ending December 31, 2026 |                 |                                                 |
| 10 | <u>Exhibit</u>                                             | <u>Schedule</u> | <u>Description</u>                              |
| 11 | A-11                                                       | A1              | Projected Revenue Deficiency (Sufficiency)      |
| 12 | A-11                                                       | A1.1            | Tree Trim Regulatory Asset – Return On          |
| 13 | A-11                                                       | A1.2            | Monroe Regulatory Asset – Return On             |
| 14 | A-12                                                       | B1              | Projected Rate Base                             |
| 15 | A-13                                                       | C2              | Projected Revenue Conversion Factor             |
| 16 | A-13                                                       | C14             | Projected Tax Effect of Interest                |
| 17 |                                                            |                 | Allowed in Ratemaking Formula - 12 Months Ended |
| 18 |                                                            |                 | 12/31/2023 and 12/31/2026                       |
| 19 | A-13                                                       | C15             | Projected Tax Effect of Interest -              |
| 20 |                                                            |                 | Synchronization Adjustment - 12 Months Ended    |
| 21 |                                                            |                 | 12/31/2023 and 12/31/2026                       |
| 22 | A-14                                                       | D1              | Projected Rate of Return Summary                |

Line  
No.

1 Infrastructure Recovery Mechanism

2 Exhibit Schedule Description3 A-33 X4 Infrastructure Recovery Mechanism – Incremental  
4 Revenue Requirement – Proposed Investment5 A-33 X5 Infrastructure Recovery Mechanism – Incremental  
6 Revenue Requirement – Alternative Investment

7

8 **Q11. Were these exhibits prepared by you or under your direction?**

9 A11. Yes, they were.

10

11 **Section A – Historical Test Period (Twelve Months Ended December 31, 2023)**12 **Q12. What information is displayed on Exhibit A-1, Schedule A1?**

13 A12. Exhibit A-1, Schedule A1 titled “Historical Revenue Deficiency (Sufficiency)”  
 14 shows the calculation of the Company’s revenue deficiency for the historical test  
 15 period based on historical rate base, overall rate of return, adjusted NOI, and a  
 16 revenue conversion factor. Line 8, of Schedule A1 shows that the Company  
 17 experienced a revenue deficiency of \$150.5 million for the historical test period.  
 18 The revenue deficiency is based on a rate base of \$21.3 billion, adjusted NOI of  
 19 \$1,044.2 million, and a required rate of return of 5.43%. The rate base balance is  
 20 carried forward from Exhibit A-2, Schedule B1. The adjusted NOI is carried  
 21 forward from Exhibit A-3, Schedule C1, which is supported by Witness Uzenski.  
 22 The defined historical required rate of return is set forth in Exhibit A-4, Schedule  
 23 D1.

24

25 **Q13. What is the Historical Rate Base?**

Line  
No.

1 A13. As shown on Exhibit A-2, Schedule B1, Historical Rate Base (line 15) is the 13-  
2 month average balances for net plant and the allowance for working capital for the  
3 period ended December 31, 2023.

4  
5 **Q14. What is the purpose of the Revenue Conversion Factor?**

6 A14. The Revenue Conversion Factor, also known as the Revenue Multiplier, is a  
7 multiplication factor that converts a utility's after-tax income deficiency /  
8 (sufficiency) into the required change in the pre-tax revenue requirement. In the  
9 historical test period, each dollar of revenue the Company received was subject to  
10 Michigan Corporate Income Tax, Municipal Income Tax, and Federal Income Tax.  
11 Line 9 of Exhibit A-3, Schedule C2, shows DTE Electric's historical test period  
12 Revenue Conversion Factor of 1.3496, which means DTE Electric was required to  
13 collect \$1.3496 in revenue to produce \$1.00 of after-tax income.

14  
15 **Q15. How did you calculate the Income Tax Savings of Interest reflected in Exhibit**  
16 **A-3, Schedule C12?**

17 A15. Exhibit A-3, Schedule C12, calculates the difference in the tax deduction amount  
18 for interest expense based on interest expense allowable in the rate case versus DTE  
19 Electric's actual interest expense for the historical test period as supplied to me by  
20 Witness Uzenski. Allowable interest expense starts with the Historical Rate Base  
21 (line 1) multiplied by the weighted cost of debt (line 2). The weighted cost of debt  
22 is the summation of the weighted costs associated with long-term debt (LTD) and  
23 short-term debt (STD) from Exhibit A-4, Schedule D1. Line 3 calculates the  
24 allowable ratemaking debt interest expense deduction while DTE Electric's actual  
25 interest expense deduction (line 4) is what was included in DTE Electric's

Line  
No.

1 computation of federal income tax per Company books. Allowable ratemaking  
2 interest expense is less than actual interest expense, which results in reducing the  
3 tax deduction by the net of these two amounts. This lower tax deduction increased  
4 federal income tax, state income tax and municipal tax expense resulting in a  
5 corresponding decrease in NOI, as shown on line 11 of Schedule C12.

6

7 **Q16. What is the Synchronization Adjustment calculated on Exhibit A-3, Schedule**  
8 **C13?**

9 A16. Tax law requires, and prior Commission Orders have allowed, a return on Job  
10 Development Investment Tax Credits (JDITC) at the rate of return for permanent  
11 capital. This tax adjustment represents the interest deduction for the debt  
12 component of that return. The purpose of the Synchronization Adjustment is to  
13 align the level of interest expense inherent in the capital structure with the  
14 Company's rate base. Exhibit A-3, Schedule C13, shows a reduction in state and  
15 municipal income tax expense (line 7) and federal income tax expense (line 10) due  
16 to the interest deduction associated with the debt component portion of JDITC.  
17 This Synchronization Adjustment reduces income tax expense and, as shown on  
18 line 11, results in a corresponding increase in NOI.

19

20 **Q17. What is DTE Electric's historical rate of return?**

21 A17. Exhibit A-4, Schedule D1, titled "Historical Rate of Return Summary" shows DTE  
22 Electric's historical test period overall rate of return on line 10, column (g). The  
23 capital structure is carried forward from the balance sheet on line 124, columns (e)  
24 through (i) of Exhibit A-2, Schedule B5 sponsored by Witness Uzenski, and equals  
25 the rate base amount on line 15, column (c) of Exhibit A-2, Schedule B1. The



Line  
No.

1 capital structure excludes any funds on deposit with trustees, and the financing  
2 related to regulatory assets and other items eliminated from the historical balance  
3 sheet by Witness Uzenski.

4

5 On Exhibit A-4, Schedule D1, the long-term debt, shown on line 1 includes  
6 reductions for the net amount of unamortized premium / discount and unamortized  
7 debt expense. DTE Electric's total long-term debt outstanding on December 31,  
8 2023 is detailed on Exhibit A-4, Schedule D2, sponsored by Witness Lepczyk. The  
9 weighted long-term debt cost for the historical period was calculated by Witness  
10 Lepczyk on Schedule D2 using the net proceeds method for each issue outstanding  
11 on December 31, 2023.

12

13 Line 2 of Schedule D1 reflects that the Company had no preferred stock  
14 outstanding.

15

16 Line 3 of Schedule D1 shows common shareholders' equity, which includes  
17 common stock outstanding, less expense, plus premium, other paid-in capital,  
18 retained earnings and Other Comprehensive Income (OCI) adjustments. The cost  
19 of common shareholders' equity utilized for this exhibit for the historical test period  
20 is the 9.90% that was authorized by the Commission in Case No. U-21297 as  
21 indicated on Exhibit A-4, Schedule D5, sponsored by Witness Lepczyk.

22

23 The cost of short-term debt, on line 5, is the actual average short-term borrowing  
24 cost of the Company in the historical test period. The cost of short-term debt is  
25 detailed on Exhibit A-4, Schedule D3, sponsored by Witness Lepczyk.

Line  
No.

1 The Job Development – ITC amounts on lines 6 (JDITC – Debt) and 7 (JDITC –  
2 Equity) of Schedule D1 reflect the corresponding permanent capital percentages for  
3 long-term debt and common equity. The associated returns for JDITC – Debt and  
4 JDITC – Equity reflect the corresponding permanent capital cost rates for long-  
5 term debt and common shareholders' equity, respectively. This calculation  
6 complies with the 1986 Internal Revenue Service Regulation, Section 1.46-6, to  
7 assign a rate of return to JDITC at the weighted average cost of permanent capital.

8

9 Net deferred income taxes (line 9) are at zero cost.

10

11 **Section B – Projected Test Period (Twelve Months Ending December 31, 2026)**

12 **Q18. What is the Revenue Deficiency for the projected test period?**

13 A18. Line 11 of Exhibit A-11, Schedule A1, shows absent rate relief, DTE Electric will  
14 experience a Total Revenue Deficiency of \$574.1 million for the projected test  
15 period, including the return on the Tree Trim Regulatory Asset (line 9) calculated  
16 on Exhibit A-11, Schedule A1.1 and the return on the Monroe Regulatory Asset  
17 (line 10) calculated on Exhibit A-11, Schedule A1.2. This deficiency is based on  
18 the Company's projected financial outlook for the twelve months ending December  
19 31, 2026. The revenue deficiency on line 8 is based on the following: a projected  
20 rate base of \$23.6 billion, adjusted NOI of \$1,107.9 million, and a projected  
21 required rate of return of 6.03%. The total revenue deficiency for the projected test  
22 period is presented on line 11 and is calculated by adding the revenue deficiency  
23 on line 8 to the return on the Company's Tree Trim Regulatory Asset (line 9) and  
24 return on the Company's Monroe Regulatory Asset (line 10).

Line  
No.

1 The calculation of rate base is detailed in Exhibit A-12, Schedule B1. The NOI for  
2 the projected test period is developed on Exhibit A-13, Schedule C1 sponsored by  
3 Witness Uzenski. The projected test period required rate of return is set forth in  
4 Exhibit A-14, Schedule D1. The components of rate base, NOI, capitalization,  
5 required rate of return, and regulatory assets are detailed within my exhibits and  
6 schedules, as well as those of Witnesses Uzenski and Lepczyk.

7

8 **Q19. What information is displayed on Exhibit A-12, Schedule B1, entitled**  
9 **“Projected Rate Base”?**

10 A19. Exhibit A-12, Schedule B1 shows the detailed composition of the Projected Rate  
11 Base (column (d)) for the projected test period on a simple average basis. Line 16,  
12 column (d), shows the total projected rate base which consists of net plant and the  
13 allowance for working capital. These amounts are carried forward to Exhibit A-  
14 11, Schedule A1. This exhibit also provides a comparison of rate base as of  
15 December 31, 2023 to the average rate base balances for the projected test period.

16

17 **Q20. What is the Projected Revenue Conversion Factor?**

18 A20. Projected Revenue Conversion Factor is 1.3496 and is used to convert after tax  
19 income into pre-tax revenue for the projected test period. Exhibit A-13, Schedule  
20 C2 calculates the Revenue Conversion Factor for the projected test period. The  
21 derivation of the revenue conversion factor is the same mathematical format as my  
22 Exhibit A-3, Schedule C2 from Section A.

Line  
No.

1 **Q21. What adjustments on Exhibit A-13, Schedule C1.1, “Adjustments to Projected**  
2 **Net Operating Income” for the Projected Twelve Months Ending December**  
3 **31, 2026 are you supporting?**

4 A21. On this exhibit, which is sponsored by Witness Uzenski, I am supporting the  
5 adjustments for:

6 1) Income Tax Effect of Interest (line 14) supported by Exhibit A-13,  
7 Schedule C14.

8 2) Interest Synchronization Tax Adjustment (line 15) supported by Exhibit  
9 A-13, Schedule C15.

10

11 **Q22. What is the adjustment for “Income Tax Effect of Interest” on Exhibit A-13,**  
12 **Schedule C1.1, line 14?**

13 A22. This NOI adjustment on line 14 of Exhibit A-13, Schedule C1.1, is the difference  
14 between the forecasted ratemaking amount of interest tax deductions allowed based  
15 on the rate case rate of return and the forecasted interest tax deductions included in  
16 the projected test period NOI supported by Witness Uzenski. This change in  
17 income tax expense is calculated on Exhibit A-13, Schedule C14. The sum of line  
18 7 and line 10 of Schedule C14, column (c) reflects an adjustment to decrease  
19 income tax expenses resulting in a corresponding increase in NOI as shown on line  
20 11 column (c).

21

22 **Q23. What is the “Synchronization Adjustment” on Exhibit A-13, Schedule C1.1,**  
23 **line 15?**

24 A23. This NOI adjustment on line 15 of Exhibit A-13, Schedule C1.1 is the rate case  
25 Interest Synchronization Adjustment for the projected test period. As I have

Line  
No.

1 discussed previously in Section A of my testimony, tax law requires, and prior  
2 Commission Orders have allowed, a return on JDITC at the rate of return for  
3 permanent capital. This change in the income tax expenses is set forth on Exhibit  
4 A-13, Schedule C15. The sum of line 7 and line 10 of Schedule C15, column (c)  
5 reflects an adjustment to decrease income tax expenses resulting in a corresponding  
6 increase in NOI as shown on line 11 column (c).

7

8 **Q24. What information is reflected on Exhibit A-14, Schedule D1, page 1 of 2,**  
9 **entitled “Projected Rate of Return Summary”?**

10 A24. Exhibit A-14, Schedule D1, develops DTE Electric’s projected overall rate of return  
11 for the projected test period. The projected December 31, 2026 average balance  
12 sheet capital structure amounts, in column (b), are carried over from Exhibit A-12,  
13 Schedule B4.1, line 125, columns (e) through (i) and equals the rate base amount  
14 on line 16, column (d) of Exhibit A-12, Schedule B1. Schedule D1 calculates DTE  
15 Electric’s weighted after-tax projected rate of return on line 10, column (g). This  
16 weighted after-tax projected rate of return is carried forward to Exhibit A-11,  
17 Schedule A1, line 4 and is used in the determination of the projected revenue  
18 deficiency, excluding the return on the Tree Trim Regulatory Asset and the Monroe  
19 Regulatory Asset. Schedule D1 also calculates DTE Electric’s weighted pre-tax  
20 projected rate of return at line 10, column (i). The capital structure excludes any  
21 funds on deposit with trustees, and the financing related to regulatory assets and  
22 other items eliminated from the historical balance sheet by Witness Uzenski.

23

24 Long-term debt, shown on line 1 of Schedule D1, includes reductions for the net  
25 amount of unamortized premium / discount and unamortized debt expense. This

Line  
No.

1 balance of long-term debt represents 49.25% of DTE Electric's permanent capital.  
2 DTE Electric's projected total long-term debt outstanding as of December 31, 2026  
3 is detailed on Exhibit A-14, Schedule D2, sponsored by Witness Lepczyk. The  
4 weighted long-term debt cost was calculated by Witness Lepczyk on Schedule D2  
5 using the net proceeds method for each issue outstanding as of December 31, 2026  
6 including the financing cost of new debt issues.

7

8 Line 2 of Schedule D1 reflects that the Company has no preferred stock  
9 outstanding.

10

11 Line 3 of Schedule D1 shows common shareholders' equity, which includes  
12 common stock outstanding, less expense, plus premium, paid-in capital, retained  
13 earnings and other comprehensive income (OCI) adjustments. This level of  
14 common equity represents 50.75% of DTE Electric's permanent capital in the  
15 projected test period. The cost of common shareholders' equity utilized for this  
16 exhibit is 10.75%, which is supported by DTE Electric Witness Nelson in her  
17 testimony.

18

19 The cost of short-term debt, on line 5, is the forecasted average short-term  
20 borrowing cost of the Company for the projected test period supported by Witness  
21 Lepczyk on Exhibit A-14, Schedule D3.

22

23 The Job Development – ITC amounts on line 6 (JDITC – Debt) and line 7 (JDITC  
24 – Equity) of Schedule D1 reflect the corresponding permanent capital percentages  
25 for long-term debt and common equity. The associated returns for JDITC–Debt

Line  
No.

1 and JDITC–Equity reflect the corresponding permanent capital cost rates for long-  
2 term debt and common shareholders’ equity, respectively. This calculation  
3 complies with the 1986 Internal Revenue Service Regulation, Section 1.46-6, to  
4 assign a rate of return to JDITC at the weighted average cost of permanent capital.

5

6 Average projected deferred income taxes (line 9) are at zero cost of capital.

7

8 **Q25. What information is reflected on Exhibit A-14, Schedule D1, page 2 of 2,**  
9 **entitled “Projected Rate of Return - Base Rate Request and Monroe**  
10 **Regulatory Asset”?**

11 A25. The Commission approved a settlement agreement in the Company’s Integrated  
12 Resource Plan (IRP) in Case No. U-21193 on July 26, 2023. The settlement  
13 stipulates that “[t]he parties further agree that the remaining [net book value] of  
14 Monroe as of December 31, 2024, will be recovered through a regulatory asset with  
15 a return on equity (ROE) that will be set at 9.0% amortized over 15 years beginning  
16 upon the issuance of an order in the company’s next rate case.” Exhibit A-14,  
17 Schedule D1, page 2 of 2, performs the calculation of the rate of return to be applied  
18 to the Monroe regulatory asset.

19

20 Lines 1 through 7 are a restatement of Exhibit A-14, Schedule D1, page 1 of 2,  
21 summarizing the percent of capitalization, cost rate, pre-tax and after-tax rates of  
22 return. Lines 8 through 14 recalculate the pre-tax and after-tax rates of return  
23 utilizing a 9.0% return on equity for Common Shareholders’ Equity and the equity  
24 component of the Job Development – ITC. The pre-tax rate of return calculated on

Line  
No.

1 line 14, column (f), is utilized on Exhibit A-11, Schedule A1.2 to determine the  
2 return on the Monroe Regulatory Asset.

3

4 **Return On DTE Electric's Tree Trim Surge Proposal**

5 **Q26. What information is provided on Exhibit A-11, Schedule A1.1 entitled "Tree**  
6 **Trim Regulatory Asset – Return On"?**

7 A26. Exhibit A-11, Schedule A1.1, identifies the return on the Tree Trim Regulatory  
8 Asset for the projected test period relating to the Tree Trim Surge proposal as  
9 discussed by Company Witness Steudle. Line 2 is the average balance for the Tree  
10 Trim Regulatory Asset as calculated on lines 8 through 16, based on the  
11 expenditures supported by Witness Steudle on Exhibit A-13, Schedule C5.6.1. The  
12 schedule contains two reductions to the asset balances: \$156.9 million for amounts  
13 approved to be securitized in Case No. U-21015 (page 91 of Order dated June 23,  
14 2021) and \$340.2 million for amounts the Company plans to securitize in 2026.  
15 The Return on Tree Trim, shown on line 6 is based on the Average Net Rate Base  
16 on line 4 multiplied by the pre-tax Authorized Rate of Return on Permanent Capital  
17 on line 5. The pre-tax Authorized Rate of Return on Permanent Capital is  
18 calculated on Exhibit-14, Schedule D1 and was utilized as instructed by Company  
19 Witness Lepczyk.

20

21 **Return On DTE Electric's Monroe Regulatory Asset**

22 **Q27. What information is provided on Exhibit A-11, Schedule A1.2 entitled**  
23 **"Monroe Regulatory Asset – Return On"?**

24 A27. Exhibit A-11, Schedule A1.2, identifies the return on the Monroe Regulatory Asset  
25 for the projected test period relating to the balance of Monroe Power Plant that is



Line  
No.

1 not being securitized and is to be recovered as a regulatory asset over fifteen years  
2 as discussed by Company Witness Uzenski. Line 2 is the average balance for the  
3 Monroe Regulatory Asset as calculated on Exhibit A-12, Schedule B4.4 and  
4 supported by Witness Uzenski. The Return on Monroe Regulatory Asset, shown  
5 on line 4 is based on the average balance from line 2 multiplied by the Pre-tax  
6 Weighted Average Cost of Capital on line 3 as calculated on Exhibit A-14,  
7 Schedule D1, page 2.

8

9 **Revenue Requirement for DTE Electric's Infrastructure Recovery Mechanism**

10 **Q28. What information is provided on Exhibit A-33, Schedule X4 entitled**  
11 **"Infrastructure Recovery Mechanism – Incremental Revenue Requirement –**  
12 **Proposed Investment"?**

13 A28. Exhibit A-33, Schedule X4, page 1, identifies the annual incremental Revenue  
14 Requirements for DTE Electric's IRM program years 2024<sup>1</sup> through 2029 related  
15 to the Distribution Operations plant in service discussed by Company Witness  
16 Willis. The Revenue Requirement components consist of Return on Net Rate Base,  
17 Depreciation, and Property Taxes. Lines 38 through 41, on page 1 of Exhibit A-  
18 33, Schedule X4 show the underlying Revenue Requirement amounts for years  
19 2024<sup>1</sup> through 2029 that are used by Company Witness Cejas Goyanes to derive  
20 the IRM Cost of Service by Voltage Class for years 2027 through 2029. The  
21 revenue requirement calculation for years 2024<sup>1</sup>, 2025, and 2026 within this exhibit  
22 utilize the same plant in service amounts, rate of return, depreciation rates, and  
23 property tax millage rates as those approved for the IRM by the Commission within  
24 their respective orders (DTE Electric Rate Case Nos. U-21297 and U-21534). As

---

<sup>1</sup> The 13 months ended December 31, 2024

Line  
No.

1 such, the calculated revenue requirements for 2024<sup>1</sup>, 2025, and 2026 are identical  
2 to what was ordered within the respective cases.

3  
4 Lines 21 through 28 represent the Distribution Operations in-serviced investment  
5 amounts summarized by Witness Willis on Exhibit A-33, Schedule X1. Lines 31  
6 through 35, calculate the Average Net Rate Base. This incremental "Net Rate  
7 Base" reflects traditional Rate Base (Net Utility Plant) less Accumulated Deferred  
8 Income Taxes. The Return on Net Rate Base, shown on line 38, is based on the  
9 Average Net Rate Base multiplied by the pre-tax rate of return. Depreciation, line  
10 39, is based on the half year convention. Property Taxes on line 40 are derived on  
11 page 2 of this exhibit.

12

13 **Q29. What are the installation capital and removal capital amounts presented on**  
14 **Exhibit A-33, Schedule X4 and how are they treated for revenue requirement**  
15 **purposes**

16 A29. Lines 3 through 9 represent the Distribution Operations installation capital amounts  
17 summarized by Witness Willis on Exhibit A-33, Schedule X1. Lines 12 through  
18 18 represent the removal capital summarized by Witness Willis on the same exhibit.

19

20 Removal costs are capitalized and included in rate base. They are not recorded as  
21 plant in service but are instead recorded as a debit within accumulated depreciation.  
22 Due to the amount of removal costs incurred starting in 2027, accumulated  
23 depreciation on line 32 begins to show as having a debit balance when it would  
24 normally show as a credit balance. In these instances, accumulated depreciation is  
25 an increase to rate base.

Line  
No.

1 Removal costs are still considered part of the capitalized asset cost and are thus  
2 included in rate base and earn a return by decreasing accumulated depreciation  
3 (thus increasing net rate base). However, as removal capital is not included in plant  
4 in service, the costs are not factored into the calculation for property tax expense  
5 and no associated depreciation expense is recognized

6

7 **Q30. What is the basis for the pre-tax rate of return utilized?**

8 A30. For the new IRM program years being proposed in this rate case (2027 through  
9 2029), DTE Electric's total pre-tax rate of return from Exhibit A-14, Schedule D-  
10 1, line 10 is being applied to Average Net Rate Base to determine Return on Net  
11 Rate Base. DTE Electric's total pre-tax rate of return includes the dilutive effects  
12 of Accumulated Deferred Income Tax as a source of capital. As such, the IRM  
13 program years that use this rate do not include Accumulated Deferred Taxes (line  
14 33) in the calculation of Net Rate Base and do not calculate the tax depreciation  
15 needed to determine deferred income tax expense (page 2, lines 8 through 21).

16

17 For the IRM program years that have already received Commission approval (2024  
18 through 2026), the pre-tax rate of return utilized is DTE Electric's permanent  
19 capital projected weighted cost rates as ordered in the respective rate cases, grossed  
20 up by the appropriate pre-tax multiplier discussed previously in my testimony. As  
21 the rate base for these IRM program years is shown net of deferred taxes, the  
22 weighted cost of permanent capital is used as the rate of return.

23

24 **Q31. What is the basis for the depreciation rate utilized on Exhibit A-33, Schedule**  
25 **X4?**

Line  
No.

1 A31. The depreciation rate reflects the composite depreciation rate for distribution plant,  
2 as supported by Witness Uzenski on Exhibit A-13, Schedule C6, page 2, line 9,  
3 column (h). The depreciation rate is applied to the projected plant in service for the  
4 three years shown on Exhibit A-33, Schedule X4.

5

6 **Q32. What is the purpose of page 2 of Exhibit A-33, Schedule X4?**

7 A32. Page 2 of Exhibit A-33, Schedule X4 shows the calculations of the accumulated  
8 deferred tax expense used in the derivation of Net Rate Base (for previously  
9 approved program years 2024 through 2026) and the property taxes included in the  
10 revenue requirement, shown on page 1 of Exhibit A-33, Schedule X4.

11

12 **Q33. How are property taxes calculated on page 2 of Exhibit A-33, Schedule X4?**

13 A33. Property tax expense for the proposed IRM assets is applicable to both in-service  
14 and CWIP assets. Lines 24 through 32 calculate the applicable taxable value for  
15 installation capital while lines 35 through 43 calculate the applicable taxable value  
16 for CWIP. The property tax assessment is calculated by multiplying the total  
17 taxable value (line 45) by the millage rate, which is supported by Witness  
18 Wisniewski. Lines 49 through 51 calculate the applicable property tax expense for  
19 the respective IRM program. The method utilized in this calculation is designed to  
20 align with how the Company records property tax expense and is described in detail  
21 by Witness Wisniewski.

22

23 **Q34. How is the Company proposing to reconcile actual investment to the**  
24 **investment proposed for IRM treatment in the instant case?**

Line  
No.

1 A34. The Company's proposed reconciliation is more fully described by Witness Willis.  
2 At a high level, the Company is proposing that after the conclusion of each calendar  
3 year, the Company would calculate a revenue requirement based on total and in-  
4 serviced investments for the previous year. This actual revenue requirement would  
5 be compared to the revenue requirement ordered by the Commission and calculated  
6 in a manner consistent with Exhibit A-33, Schedule X4. If the actual revenue  
7 requirement is less than the ordered revenue requirement, it would represent an  
8 over-recovery to be returned to customers. Importantly, the amount of capital that  
9 can be placed into service for each program under the IRM construct is capped at  
10 the amounts proposed by Company Witness Willis and captured in my Exhibit A-  
11 33, Schedule X4 (page 1, lines 2-28). If the Company elects to invest and place into  
12 service capital above the amounts proposed in the instant case, it can request  
13 recovery of that additional capital in a future rate case.

14

15 **Q35. What is the purpose of Exhibit A-33, Schedule X5?**

16 A35. Exhibit A-33, Schedule X5 calculates annual incremental Revenue Requirements  
17 for DTE Electric's IRM program using an alternative proposal for capital  
18 investments as discussed by Witness Willis. The Revenue Requirement calculation  
19 is performed in the same manner as Exhibit A-33, Schedule X4 as discussed above.

20

21 **Summary**

22 **Q36. What are you proposing based on your testimony in this proceeding?**

23 A36. I am proposing that the Commission issue findings consistent with the matters  
24 presented in my testimony. Specifically, as shown in Section B, on Exhibit A-11,

Line  
No.

1 Schedule A1, that DTE Electric's revenue deficiency for the projected test period  
2 is \$574.1 million.

3

4 **Q37. Does this complete your direct testimony?**

5 A37. Yes, it does.