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September 12, 2025

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

RE: 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
MPSC Case No. U-21860

Dear Ms. Felice:

Attached for electronic filing in the above captioned matter are DTE Electric Company's Rebuttal Testimony and Exhibits of Witnesses, Steven B. Ambrose, Marco A. Bruzzano, Shawn D. Burgdorf, Rodrigo Cejas Goyanes, Bill Chiu, Michael S. Cooper, Jeffrey C. Davis, Jason D. De Stigter, Matthew A. Fix, Neal T. Foley, Margaret E. Guillaumin, Christopher J. Hartley, Brian L. Hill, Allen J. Kryscynski, Timothy J. Lepczyk, Joyce E. Leslie, Markus B. Leuker, Timothy S. Lyons, David C. Milo, Jennifer E. Nelson, Stephen P. Rademacher, Joseph E. Robinson, Akarsh Sheilendranath, Jason E. Sparks, Rachel C. Steudle, Ryan M. Stowe, Anthony Turner, Theresa M. Uzenski, Kirk M. Vangilder, Aaron Willis, and Sherri L. Wisniewski. Also attached is the Proof of Service.

In addition, Mr. DeStigter's confidential rebuttal testimony; Ms. Guillaumin's confidential rebuttal testimony; Mr. Stowe's CEII confidential rebuttal testimony, Exhibit A-50 CEII confidential Sch QQ4; and Mr. Rademacher's Exhibit A-53, confidential Schedules TT5, TT6 and TT12, will be filed under seal with the Commission. The confidential rebuttal testimony exhibits, and the confidential schedules will be sent to Staff and the persons who have signed the appropriate Non-Disclosure Certificate associated with the Protective Order issued in this proceeding. The confidential rebuttal testimony, and confidential exhibit schedules are also being provided to the respective parties via the following secure portal links listed below:

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Public Portal Link:

[U-21860 Electric Rate Case - Public Discovery - Rebuttal Filing Documents - All Documents](#)

Confidential Portal Link:

[U-21860 Electric Rate Case - Protected Responses - All Documents](#)

CEII Portal Link:

[DTERegConfPortal - U-21860 CEII Confidential - All Documents](#)

Very truly yours,

Jon P.
Christinidis

Jon P. Christinidis

Digitally signed by Jon P.
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JPC/erb
Attachments
cc: Service List

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

REBUTTAL TESTIMONY

OF

MARCO A. BRUZZANO

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF MARCO A. BRUZZANO

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1 **Q1. Please state your full name and by whom you are employed?**

2 A1. My name is Marco A. Bruzzano, and I am employed by DTE Electric Company.

3

4 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
5 **Company (DTE Electric or Company)?**

6 A2. Yes.

7

8 **Purpose of Testimony**

9 **Q3. What is the purpose of your rebuttal testimony?**

10 A3. The purpose of my rebuttal testimony is to respond to certain positions taken by
11 Witnesses Dauphinais and York on behalf of the Association of Businesses
12 Advocating Tariff Equity (ABATE), Witness Coppola on behalf of the Attorney
13 General (AG), Michigan Public Service Commission (MPSC or Commission) Staff
14 (Staff) Witnesses Rueckert and Ufolla, and Witness Bunch on behalf of the Citizens
15 Utility Board and the Natural Resources Defense Council (CUB-NRDC).

16

17 **Q4. Are you sponsoring any exhibits in this proceeding?**

18 A4. Yes. I am sponsoring the following exhibits:

<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
A-58	ZZ1	Forecasted Inflation Methodologies

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1 **Inflation Rate**

2 **Q5. What intervenor positions related to the Company's proposed inflation rates**
3 **are you addressing?**

4 A5. I will address several intervenor positions related to the Company's proposed
5 inflation rates. AG Witness Coppola, ABATE Witness York, and Staff recommend
6 that the Commission reject the Company's proposed "blended" inflation rate and
7 instead use an alternative rate. CUB-NRDC Witness Bunch recommends changes
8 to the inputs to the blended rate, as well as an adjustment to 2026 inflation.

9

10 **Q6. Can you summarize AG Witness Coppola's and ABATE Witness York's**
11 **recommendation to reject the Company's proposed "blended" inflation rate**
12 **and instead use an alternative rate?**

13 A6. Yes. In his direct testimony on page 17, AG Witness Coppola argues for the use of
14 CPI-Urban (CPI-U) inflation rates of 2.8% for 2025 and 2.4% for 2026 based on
15 the "June 2025 US Economic Outlook report" instead of the Company's inflation
16 rates of 3.0% for 2025 and 3.10% for 2026.

17

18 Similarly, ABATE Witness York recommends that the Commission reject the
19 Company's proposed labor inflation rate, arguing that "[t]here are many moving
20 pieces with respect to the Company's labor expense" (page 9). She specifically cites
21 the number of employees leaving and being replaced by lower wage employees as
22 variables that could impact labor wage escalation. Instead, she recommends the use
23 of the Real GDP Chained Price Index for both labor and non-labor costs, arguing it
24 is superior to the CPI as proposed by the Company for non-labor costs (page 12).
25 ABATE Witness York concludes by highlighting that her recommended approach

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1 “...does not cure the deficiency for changes in the tenure of employees, but at least
2 relies on independent factors to project escalations in labor costs” (page 12).

3

4 **Q7. Does the Company agree with AG Witness Coppola’s and ABATE Witness**
5 **York’s recommendations to reject the Company’s proposed “blended”**
6 **inflation rate and instead use an alternative rate?**

7 A7. No. The Company first emphasizes that its blended method supported in this case
8 by Company Witnesses Uzenski and Fix is consistent with the January 23, 2025
9 Commission Order in Case No. U-21534. That Order states “On this record, the
10 Commission approves the use of the blended rate, and directs DTE Electric, in its
11 next rate case, to provide further detail on the company-specific dynamics that
12 justify rejection of the CPI-U or a similar widely-used rate for labor costs” (page
13 75).

14

15 The use of a composite rate continues to best reflect the inflationary pressures faced
16 by the Company. It rightfully separates labor inflation, which is subject to
17 Company-specific dynamics like collective bargaining agreements where there is
18 an established rate of inflation, from non-labor inflation, as described by Company
19 Witness Fix’s revised direct testimony. Neither AG Witness Coppola nor ABATE
20 Witness York provide evidence that suggests this separation is inappropriate or that
21 the Commission erred when it approved the use of a composite rate in the
22 Company’s most recent general rate cases.

23

24 AG Witness Coppola provides no specific justification for his proposal but to
25 indicate that generally CPI includes wage inputs. However, this is no different than

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1 prior cases in which the Commission has considered this reasoning and
2 appropriately determined that a labor inflation specific rate is reasonable to include
3 in the blended calculation.

4
5 Similarly, while ABATE Witness York provides a description of the Real GDP
6 Chained Price Index, she has not provided compelling evidence that it is superior
7 to the CPI-Urban rate in projecting *utility-specific* non-labor costs. She discusses,
8 for example, how the Real GDP Chained Price Index accounts for consumer
9 substitution, but does not demonstrate that it is appropriate for utility-specific costs,
10 especially considering the limited ability a utility has for substitution.

11
12 Further, the CPI is a well-established and widely used measure of inflation. The
13 basket of goods incorporated in the CPI is updated periodically. According to the
14 U.S. Bureau of Labor Statistics (BLS), these updates are made to “reflect more
15 recent consumer spending patterns; this provides a logical opportunity to rework
16 the item classification scheme so that it will recognize the emergence of new items,
17 the changes to existing items and their relative importance, and the ways that people
18 view consumer goods and services.”¹

19
20 Given the lack of evidence that their proposed rates are superior to the previously
21 approved blended rate and its specific components, ABATE Witness York’s and
22 AG Witness Coppola’s recommendations should be rejected.

23

24 **Q8. Can you summarize Staff’s recommendation regarding inflation rates?**

¹ Bureau of Labor Statistics, accessed August 13, 2024
<https://www.bls.gov/cpi/additional-resources/revision-1998-item-structure.htm>

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1 A8. Yes. Staff Witness Ufolla proposes alternative inflation rates of 2.73% in 2025 and
2 2.66% in 2026 based on “the average of projections from IHS Global Insight, The
3 Federal Reserve, and the Congressional Budget Office [CBO] for future years”
4 (page 24). According to Staff exhibit S-4 D-3a, these averages reflect Personal
5 Consumption Expenditures (PCE) inflation for the Federal Reserve and CPI
6 inflation for the CBO and IHS Global.

7

8 Staff Witness Rueckert additionally says “The Commission has rejected use of this
9 “blended rate” in prior general rate cases. See MPSC Case No. U-20162, Order,
10 May 2, 2019, p 74.”, and continues “The Company’s composite inflation rate
11 contains a wage component the Company is partially in control of. The CPI-Urban
12 index that the Company incorporates into its “blended” inflation factor is, alone,
13 much lower than the actual inflation factors the Company utilized in its
14 calculations, and closer to Staff witness Ufolla’s inflation Factors” (page 6).

15

16 **Q9. Does the Company agree with Staff’s inflation recommendations?**

17 A9. No. Witness Ufolla does not offer discussion as to why PCE inflation is appropriate,
18 or how the CPI figures from the CBO and IHS Global compare to the CPI-U used
19 by the Company for non-labor inflation. The Company also highlights that while it
20 does not dispute the Commission’s 2019 Order, more recent Commission decisions,
21 including the January 2025 Order in the Company’s previous general rate case
22 (Case No. U-21534), support the use of blended inflation (see page 75).

23

24 Regarding Staff’s observation that the Company is “partially” in control of wage
25 growth and therefore a labor specific component is unnecessary, Company Witness

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1 Fix addresses this in his revised direct testimony, underscoring that the generic
2 labor costs assumed in CPI (or PCE) are not reflective of the Company's or the
3 industry's specific wage growth considerations. That testimony says in part:

4 "Based on existing Collective Bargaining Agreements, the Company is
5 obligated to increase pay rates by at least 3% annually through the term of
6 the contracts. In addition to scheduled pay rate increases, the agreements
7 also provide for progression increases for those employees that have not yet
8 achieved the maximum pay rate for their positions. Non-represented
9 employee compensation is generally adjusted annually based on a review of
10 pay practices of other employers, changes in the external competitive
11 market and internal pay equity."

12
13 As such, the Company recommends not adopting Staff's proposed adjustments to
14 inflation.

15
16 **Q10. Can you summarize NRDC-CUB Witness Bunch's recommendation**
17 **regarding inflation rates?**

18 A10. Yes. NRDC-CUB Witness Bunch separately discusses the Company's non-labor
19 and labor inflation assumptions. Regarding non-labor, Witness Bunch proposes no
20 change to using CPI-U but recommends more recent data from July 2025.

21
22 Regarding labor inflation, his core recommendation is "In instances when historical
23 data is not available, such as for bridge year 2025 and projected test year 2026,
24 multiple exogenous factors can impact total labor costs. In such instances, wage
25 growth should be offset with a labor productivity factor, so that the escalator

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1 reflects the cost of providing the same level of service...BLS publishes this data
2 for all 50 states across different sectors. I use the Labor Productivity Index of
3 Michigan private, non-farm workers to arrive at a 1.96% labor-productivity offset”
4 (page 21). He recommends “a labor factor of 1.04% per year, calculated as DTEE’s
5 proposed 3.0% wage inflation minus a 1.96% labor-productivity offset” for 2025
6 and 2026 (page 22).

7

8 In addition, Witness Bunch recommends labor inflation for 2024 based on his
9 calculation of the Company’s compound average growth in total compensation
10 costs for the period 2019 through 2024 of 0.23% (Bunch Direct, page 22, lines 6-
11 10). In sum, Witness Bunch proposes inflation factors of “0.6%, 1.3%, and 1.2%
12 for 2024, 2025, and 2026, respectively” (page 23).

13

14 Witness Bunch then claims that the 2026 inflation factor should be “reduced by
15 50% because this adjustment assumes the test year O&M expenses will be spread
16 evenly over the test year and only half of inflation will be affecting customer rates.
17 To include all of the 2026 projected inflation factor would assume all O&M
18 expenses in 2026 would be made or priced based upon the year end 2026 inflation
19 levels and incur the full inflation factor. Reducing the 2026 test factor by 50%
20 assumes that these expenses are incurred evenly throughout the test year” (page 30.

21

22 **Q11. Does the Company agree with CUB-NRDC Witness Bunch’s**
23 **recommendations regarding labor inflation productivity?**

24 A11. No. Considering non-labor inflation, the Company included in its direct case the
25 best available forecasts for current and future year inflation. Regarding labor

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1 inflation, there are multiple flaws in the productivity analysis. First, Witness Bunch
2 uses incomparable periods for his calculation of a proposed labor inflation rate. He
3 uses historical labor productivity offsets (2018-2024), which are unsupported in
4 their applicability to forecast future labor cost offsets or productivity gains, and
5 applies them to future wage growth. He provides no evidence of forecasted
6 productivity offsets but to use an annual average of prior years, years which the
7 Company notes include among the most atypical economic conditions in a
8 generation considering the overlap with a global pandemic. Second, the analysis
9 does not explain why the category of “Michigan private non-farm workers” is
10 applicable to the Company or the industry. It is entirely possible that dissimilar
11 industries such as retail are responsible for the change in labor productivity in
12 greater proportion than regulated energy companies.

13

14 In addition, as discussed by Company Witness Fix in his rebuttal testimony,
15 Witness Bunch’s use of the compound annual growth rate of 0.23% in the
16 Company’s total compensation for the years 2019 through 2024 is seriously flawed
17 and should be rejected because it fails to recognize the reduction in employee
18 headcount and the actual increases in employee compensation over that time period.
19 In addition, as also stated above, there is no rationale for why cost reductions in
20 prior periods would translate to future projections.

21

22 **Q12. Do you agree with Witness Bunch’s proposal to reduce 2026 inflation by half?**

23 A12. No. The basis for the Company’s projected test year is the 2023 historical test year.

24 A simplified view of the Company’s inflation methodology is:

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- 1 • Start with full year 2023 costs (no in-year inflation adjustments, all
- 2 nominal)
- 3 • Adjust for 2024 inflation
- 4 • Adjust for 2025 inflation
- 5 • Adjust for 2026 inflation

6 The Company's starting point in this case (2023 actual costs) is a full year. Those
 7 costs were incurred over the course of the year and were subject to significant intra-
 8 year inflationary pressures. Table 1 below shows the actual 12-month trailing CPI-
 9 U by month in 2023.

10

11 **Table 1 2023 12-month Trailing CPI-U²**

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg ³
6.4%	6.0%	5.0%	4.9%	4.0%	3.0%	3.2%	3.7%	3.7%	3.2%	3.1%	3.4%	4.1%

12

13 Table 1 demonstrates that a dollar spent (whether O&M or capital) in January
 14 would not have had the same purchasing power in December, as it would have
 15 accumulated the impact of inflation throughout the year. However, in the test year
 16 costs described above, there is no adjustment to the nominal expenditure made in
 17 January despite the fact that, on a real basis, they are different (in 2023, this
 18 difference was about 4.1%, see Table 1). Using nominal dollars is an appropriate
 19 approach for several reasons, including the level of complexity required to adjust
 20 intra-year actuals for inflation, and the fact that ratemaking is conducted on a 12-
 21 month basis and not a monthly basis. Said differently, while the Company's

² Bureau of Labor Statistics, accessed September 4, 2025 [Table 5. Chained Consumer Price Index for All Urban Consumers \(C-CPI-U\) and the Consumer Price Index for All Urban Consumers \(CPI-U\): U.S. city average, all items index - 2025 M07 Results](#)

³Bureau of Labor Statistics, accessed September 4, 2025 [Consumer Price Index - December 2023](#)

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1 historical test year accurately captures the nominal costs, it understates historical
2 real costs by approximately half of the average inflation rate in that year⁴. The
3 projected test year costs account for this by applying inflation for the full projected
4 year. Applying only 50% of projected inflation in 2026, as Witness Bunch
5 proposes, would essentially penalize the Company for the impact of six months of
6 inflation costs already excluded in the historical. The Company would then only
7 recover 2.5 years of inflation adjustment for three years of elapsed time.

8
9 Table 2 below, based on Exhibit A-58 Schedule ZZ1, describes this dynamic using
10 an example which assumes steady 3% inflation and steady spending of \$100 per
11 month in 2023.

- 12 • Box (a) describes the currently approved method, which uses nominal
13 historic costs and full year inflation for the projected test year. This yields
14 \$1,311 in 2026 costs.
- 15 • Box (b) describes the impact of adjusting the historical costs for monthly
16 inflation (real 2023 costs). This yields \$1,329 in 2026, or ~1.4% above the
17 approved method.
- 18 • Box (c) describes Witness Bunch's proposal, which uses nominal 2023
19 costs and applies only a half year inflation in 2026. This yields \$1,292 in
20 2026, or about ~1.5% less than the approved method.
- 21 • Box (d) describes Witness Bunch's half year method for 2026 when applied
22 to real 2023 costs. This yields \$1,310 in 2026, which is essentially identical
23 to the approved method and underscores the relevance of a nominal vs. real
24 starting point.

⁴ Simplified, assuming consistent month/month inflation and consistent month/month spend.

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Table 2 Illustrative impacts of inflation calculations on 2026 costs

	Full year 2026 inflation	Half year 2026 inflation
Nominal 2023	(a) \$1,311	(c) \$1,292
Real 2023	(b) \$1,329	(d) \$1,310

2

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13

This demonstrates that Witness Bunch's half-year proposal would be reasonable only if the Company adjusted historical costs for in-year inflation and utilized real dollars, as opposed to nominal dollars, for the historical year. However, as described above, this is impractical and unnecessary. Therefore, given the nominal starting point for historical costs, applying only a half year inflation in the projected year understates the appropriate amount by ~1.5%, or in this example exactly ½ of the assumed 3% inflation rate. The Company would under-recover by half a year of inflation costs.

As such, Witness Bunch's inflation recommendations should be rejected, and the Company's proposal should be accepted.

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1 **Projected Test Year**

2 **Q13. What intervenor positions related to the Company's use of a forward test year**
3 **are you addressing?**

4 A13. I will address ABATE Witness Dauphinais's recommendation that the Commission
5 reject the use of a forward test year.

6

7 **Q14. Can you summarize ABATE Witness Dauphinais' recommendation that the**
8 **Commission reject the use of a forward test year?**

9 A14. Yes. In his testimony ABATE Witness Dauphinais recommends that the
10 Commission reject the Company's use of a forward test year, asserting that the use
11 of a forward test year:

- 12 • "...has caused and continues to cause customers to experience rate increases
13 sooner because rates are being based on future projections" (page 12).
- 14 • "...has resulted in higher rates for customers than if rates were based on the
15 historical test year" (page 12).
- 16 • "...has allowed and continues to allow DTE to fill its projections with
17 proposed capital expenditures and expenses that either DTE has not
18 irrevocably committed to making or otherwise can avoid if it finds it
19 advantageous to do so to improve its realized rate of return for its
20 shareholders" (page 12).
- 21 • "...greatly handicaps the Commission Staff and intervenors in reviewing
22 DTE's rate filings to ensure the projected capital expenditures and expenses
23 are reasonable because they are not actual capital expenditures and expenses
24 reflected on DTE's books, but rather projections developed over many
25 separate cost subaccounts and revenue categories" (page 12).

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1 Further, on page 13 of his direct testimony, Witness Dauphinais offers a definition
2 of “known and measurable changes” by suggesting such changes to costs are
3 “inescapable and precisely identifiable in amount and timing.” He goes onto argue
4 that “[f]uture capital expenditures and projected expenses are often not inescapable,
5 not precisely identifiable in amount and timing, or both.”

6

7 Although the Company disagrees with ABATE’s contention that the Commission
8 is legally authorized to reject the use of a forward test year, ABATE Witness
9 Dauphinais recommends the following if the Commission allows the use of a
10 forward test year:

11

12 “I recommend the Commission be much more vigilant and aggressive with
13 respect to ensuring the expenses and investments being projected by DTE for
14 its projected test year are truly expenses and investments that are necessary to
15 provide reliable electric service at lowest reasonable cost. The Commission
16 should also ensure that DTE is irrevocably committed to incur its projected
17 expenses and investments or otherwise cannot avoid them. Finally, the
18 Commission should ensure that DTE’s projected investments and expenses are
19 precisely quantified by DTE with respect to both amount and the specific
20 quarter in which DTE will incur these investments and expenses” (page 16).

21

22 **Q15. Does the Company agree with ABATE Witness Dauphinais’ recommendation**
23 **that the Commission reject the use of a forward test year?**

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No.

1 A15. No. To start, the forward test year is authorized by law and the Company has
2 utilized, and the Commission has approved, the current projected test year
3 methodology for all the Company's rate cases filed dating as far back as 2008.

4

5 In addition, the Company disagrees with ABATE Witness Dauphinais' definition
6 of "known and measurable changes". The forward test year is a projection of the
7 expenditures that are likely to be made given the information known at the time of
8 the rate case filing.

9

10 Further, the Company believes ABATE Witness Dauphinais' assertions that the use
11 of a forward test year results in customers experiencing "rate increases sooner
12 because rates are being based on future projections" and that it "has resulted in
13 higher rates for customers than if rates were based on the historical test year" (page
14 12) are misleading. Under a forward test year methodology, base rates are proposed
15 for a future twelve-month period and, once approved by the Commission, go into
16 effect no earlier than the start of that future period. As such, the implementation of
17 new rates matches the projected costs approved by the Commission. This matching
18 of costs and rates supports the timely recovery of costs and helps ensure the
19 Company can continue investing in projects and programs that deliver benefits to
20 customers, such as improvements in reliability.

21

22 Withholding rate increases until after costs have been incurred would create an
23 unreasonable and unjust mismatch between when costs are incurred and when they
24 are recovered from customers. This is otherwise known as "Regulatory Lag" and
25 would challenge the Company's ability to execute capital investments and realize

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1 reliability improvements and other benefits, such as supporting the transition to
2 cleaner generation.

3

4 As it pertains to ABATE Witness Dauphinais' concerns related to the Commission
5 approving capital investment that the Company has not "irrevocably committed to
6 making," the Company disagrees that an "irrevocable commitment" is needed for
7 the Commission to approve capital investments for recovery. As discussed above,
8 the forward test year is a projection of the expenditures that are likely to be made
9 given the information known at the time of the rate case filing. The Company's
10 witnesses in this case support the reasonableness and prudence of these
11 investments, including the timing and estimated cost of investments.

12

13 The Company further highlights that in this case it has proposed an extension and
14 expansion of its Distribution Investment Recovery Mechanism (IRM). The IRM
15 ensures that the Company invests authorized amounts for their intended purposes
16 or returns the revenue to customers – an irrevocable commitment. This directly
17 addresses ABATE Witness Dauphinais' concerns, and yet he opposes the
18 expansion of the IRM elsewhere in his direct testimony.

19

20 Finally, the Company disagrees with ABATE Witness Dauphinais' assertion that
21 the use of a forward test year "greatly handicaps the Commission Staff and
22 intervenors in reviewing DTE's rate filings to ensure the projected capital
23 expenditures and expenses are reasonable" (page 12). The burden of proof within a
24 rate case falls on the Company to prove the reasonableness and prudence of its
25 proposed investments and operating expenses, and the Company notes the

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1 Commission's May 18, 2023 Order in Case No. U-18238 which adopted new rate
2 case filing requirements – those filing requirements substantially expanded the
3 detailed support for the Company's request. Commission Staff and intervenors can
4 challenge the recovery of any of the Company's proposed investments, as many
5 intervenors have done in this case. The suggestion that they are somehow
6 handicapped is unfounded.

7

8 **Rate Case Expenses**

9 **Q16. Do you agree with AG Witness Coppola's recommendation that \$7.1 million**
10 **related to rate case expenses be disallowed from the projected test year O&M**
11 **expense (page 142 of his testimony)?**

12 A16. No, for several reasons.

- 13 • Rate cases are filed to allow the utility to recover reasonable and prudent
14 costs that are necessary to provide safe and reliable service to customers,
15 not for the benefit of shareholders.
- 16 • Mr. Coppola's statement that some states do not permit recovery of rate case
17 filing costs is both misleading and not supported by evidence.
- 18 • Mr. Coppola's methodology of calculating the "cost of completing a rate
19 case" is deeply flawed.
- 20 • Disallowing prudent costs incurred to meet rate case filing requirements and
21 discovery obligations would harm the Company and its customers.

22

23 **Q17. Should shareholders bear the cost of filing a rate case?**

24 A17. No. The Company is focused on providing safe and reliable electric service for the
25 benefit of its customers, and to do so it must have adequate resources and be able

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1 to make necessary investments in its system. Those resources, and cost recovery
2 for the necessary investments, are obtained through the rate setting process. Thus,
3 filing rate cases is an essential and integral part of providing service to our
4 customers. As is discussed by numerous witnesses in this case, in the distribution
5 planning docket (Case No. U-20147), and as part of the Company's Integrated
6 Resource Plan (Case No. U-21193), the Company is making substantial capital
7 investments which require recovery. Moreover, the Commission facilitated an audit
8 of the distribution system which supports additional needed investment. Rate cases
9 must be filed to support investment, and the investments must occur to achieve the
10 customer reliability outcomes required by the Commission as part of the Service
11 Quality and Reliability Standards and the Financial Incentives and Penalties docket
12 that is currently in progress (Case Nos. U-21400 and U-21909). The AG's
13 suggestion to penalize the Company given the required capital investment and the
14 associated regulatory filings needed to finance those investments is inappropriate
15 and should be rejected.

16
17 In addition, as rate case filing requirements expand, and the Commission and
18 intervening parties have requested increased analytical support and project level
19 details (e.g., Benefit Cost Analysis, assessments of alternatives, full modeling
20 analyses, project by project variance summaries, voluminous capital approval
21 documents, increased Part III filing requirements, and so forth), the costs to the
22 Company have increased. The growing demand for more information from outside
23 parties creates a need for additional resources. Paradoxically, the more resources
24 the Company must commit to rate cases to support these growing requirements

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1 from others, the more shareholders would be penalized under the AG's
2 recommendation.

3

4 **Q18. Does Witness Coppola provide compelling justification for the precedent he**
5 **claims has been set in other jurisdictions?**

6 A18. No. Witness Coppola offers no analysis of the specific recommendation for a 50%
7 disallowance. He simply asserts its prudence based on limited examples from other
8 states without context. Mr. Coppola cites Connecticut and Colorado as example
9 states that preclude rate case expense recovery, but he also notes that these states
10 "have statutes that exclude rate case expense from recovery." Michigan has no such
11 statute, thus a comparison to these states for precedent is inappropriate. He also
12 asserts, without citation to any commission rule or order, that New Jersey and
13 Missouri have "regulatory commission precedents" for the 50% split. However,
14 with respect to New Jersey, the Company can only identify a single settlement
15 agreement in a 2024 NJ Gas Company case with such a provision⁵. That settlement
16 notes "[it] is specifically understood and agreed that this Stipulation represents a
17 negotiated agreement and has been made exclusively for the purpose of these
18 proceedings." Additionally, the Missouri Public Service Commission Staff issued
19 a report in 2013 addressing recovery of *third-party, incremental* rate case expense
20 and ultimately concluded that reasonably and prudently incurred expenses should
21 be recoverable. The Staff there suggested several different options for allocating
22 expenses based on research they had completed, one of which included
23 consideration of a 50/50 cost share while another option allowed for full recovery.⁶

⁵ NJ Board of Public Utilities, November 21, 2024 Order in BPU DOCKET NO. GR24010071 [NJBPU](#),
Page 4 of the settlement agreement

⁶ Missouri Public Service Commission Staff August 2013 Report, Case No. AW-2011-0330
<https://efis.psc.mo.gov/Document/Display/289669>

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1 Further, cherry picking legislation or regulatory precedent from another state
2 obfuscates what are certainly complex and distinct regulatory environments. For
3 example, other states may have more or fewer intervening witnesses, statutory rate
4 case timelines may be different, regulatory rules of evidence that are more or less
5 stringent and filing requirements which may be more or less extensive. The full
6 picture of the regulatory context is important to consider when making a
7 recommendation such as Witness Coppola's, however, the AG has not provided
8 any substantiating context.

9
10 Thus, the examples provided by Witness Coppola should be disregarded as
11 incomparable to applicable law and regulatory proceedings in Michigan.

12

13 **Q19. Is Mr. Coppola's assertion that certain states do not permit recovery of rate**
14 **case expenses a compelling reason to exclude them for projected test year**
15 **O&M costs?**

A19. No. Witness Coppola presumably referenced every jurisdiction supporting his
recommendation, which would suggest another 45 states plus the District of
Columbia do not follow such an approach. Mr. Coppola has not included any
evidence about which other states may or may not allow rate case expenses to be
recovered and under what circumstances.

16

17 **Q20. Why is Mr. Coppola's methodology for calculating the cost of a rate case**
18 **deeply flawed?**

19 A20. Mr. Coppola arbitrarily calculates the cost of a rate case by estimating a "cost per
20 page" by taking aggregate external consultant rate case expenses and dividing them

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1 by the total number of pages of testimony filed by external witnesses. Then he takes
2 this inappropriate cost per page amount and applies it to the total number of pages
3 filed by the Company in the instant filing. This methodology is overly simplistic
4 and deeply flawed for several reasons:

- 5 • It does not consider the actual cost of the resources that are developing each
6 page (e.g., an entry-level Company employee as compared to a very
7 experienced external senior consultant).
- 8 • It does not consider the fact that the amount of work associated with the
9 production of each page can vary significantly (e.g., a description of a
10 complex engineering analysis as compared to including financial data that
11 was already produced for other purposes).
- 12 • It does not consider that the cost of external consultants, which Mr. Coppola
13 used as a basis for his recommendation, also includes providing support to
14 other Company witnesses, and not just for drafting their own testimony.
15 That is, Mr. Coppola's methodology assumes that every dollar spent on
16 consultants is devoted to producing testimony pages for the consultant.
- 17 • It does not consider that many internal employees sponsor testimony with
18 minimal or moderate changes case-to-case, versus external consultants who
19 are often introducing new, complex topics or support into the record.

20 For these reasons, disallowing an arbitrary estimate of cost based on such a
21 simplistic and flawed analysis would be inappropriate and unfairly harm the
22 Company by denying recovery of prudently incurred costs.

23
24 **Q21. Do you have additional concerns with witness Coppola's recommendation?**

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1 A21. Yes. His recommendation would result in not funding the reasonable and prudent
2 O&M expenses needed to perform the ordinary business activities required to
3 provide safe, reliable electrical service.

4
5 The non-consultant expenses that are proposed for disallowance would not be
6 reduced when the Company does not file a rate case. This is because the internal
7 labor costs for supporting rate cases are driven primarily by employees that also
8 perform other activities. For example, a distribution operations employee may
9 primarily support long term capital planning and analysis, or engineering activities
10 associated with new customer connections, or patrolling circuits after high winds
11 looking for the cause of an outage, or other tasks requiring management of a team
12 and ongoing, day-to-day work. At times, the employee may also support rate case
13 activities as either a witness or support resource, but in the absence of a rate case
14 they remain otherwise focused on their role. The same dynamic is true for the
15 Company's accounting team, the tax team, the customer service team, the energy
16 supply team and others who have a role in rate cases but are primarily responsible
17 for running the Company on a day-to-day basis.

18
19 Disallowing prudently incurred costs based on a random assumption of rate case
20 expenses puts the funding for resources that are necessary to run the Company in
21 jeopardy. As such, this is unavoidable Company O&M and a disallowance would
22 require a reduction elsewhere, with potentially negative consequences as described
23 in my direct testimony.

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1 **Q22. Finally, should the Commission accept Mr. Coppola's recommendation to**
2 **track all costs to complete future rate cases?**

3 A22. No. This is unnecessary. As discussed in my testimony above, the labor cost of
4 internal employees supporting rate cases is fixed (apart from the effects of
5 inflation), and rate case work often simply changes the timing of other tasks for
6 these internal employees. Importantly, these resources remain employed by the
7 Company to fulfill an operational need whether a rate case is filed or not, thus
8 tracking employee time for purposes of disallowing portions of their compensation
9 in years where a rate case is filed is inequitable and imprudent. Requiring the
10 Company to track all costs to complete future rate case filings is also an added
11 burden to employees on top of the demands imposed by the ever-expanding filing
12 requirements and the 3000+ discovery questions received during the case that they
13 must navigate while also completing their normal responsibilities. The Company
14 already provides an exceptional level of detailed support in testimony, exhibits, and
15 other filing requirements for rate cases. Witness Coppola is requesting that the
16 Company take on an unnecessary task and an expense that is not beneficial to
17 customers.

18

19 **Q23. Does this conclude your rebuttal testimony?**

20 A23. 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

REBUTTAL TESTIMONY

OF

JOYCE E. LESLIE

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF JOYCE E. LESLIE

Line
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1 **Q1. Please state your full name, business address and by whom you are employed?**

2 A1. My name is Joyce E. Leslie and 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.

5

6 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
7 **Company (DTE Electric or Company)?**

8 A2. Yes.

9

10 **Purpose of Testimony**

11 **Q3. What is the purpose of your rebuttal testimony?**

12 A3. The purpose of my rebuttal testimony is to respond to certain positions taken by
13 Witnesses Nichols on behalf of Soulardarity and We Want Green, Too (collectively
14 known as the Detroit Area Advocacy Organizations or DAAO).

15

16 **Q4. Are you sponsoring any exhibits in this proceeding?**

17 A4. No.

18

19 **Corporate Memberships**

20 **Q5. What intervenor positions related to the Company's proposed recovery of**
21 **corporate membership expenses are you addressing?**

22 A5. There is one intervenor position I will address related to the Company's proposed
23 recovery of corporate membership expenses:

24 • DAAO Witness Nichols' recommendation to disallow all or a portion of the
25 Company's proposed corporate membership expenses.

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1 **Q6. What does DAAO Witness Nichols recommend related to corporate**
2 **memberships?**

3 A6. Witness Nichols makes the following recommendations on pages 56 and 57 of her
4 revised direct testimony.

- 5 • Disallow DTE Electric's entire \$1.5 million request for recovery of EEI
6 [Edison Electric Institute] membership dues from ratepayers on the grounds
7 that these costs are neither reasonable, prudent, or necessary for the
8 provision of safe and reliable utility service; nor consistent with the public
9 interest and the goals of a fair and equitable regulatory process.
- 10 • Examine closely DTE Electric's justification for its other membership
11 requests and reject those that either fund political advocacy or lack
12 sufficient detail to demonstrate tangible customer benefits pursuant to the
13 Commission's orders in Cases Nos. U-21297 and U-21534.
- 14 • Make clear that failure to comply with the disclosure requirements for
15 discretionary memberships set forth in Cases Nos. U-21297 and U-21534
16 will result in the rejection of cost recovery in all future rate cases.

17

18 **Q7. Does the Company agree with DAAO Witness Nichols' recommendation to**
19 **disallow a portion or all of the Company's proposed corporate membership**
20 **expenses?**

21 A7. No. Specifically, DAAO Witness Nichols recommends disallowance of the
22 Company's membership of the EEI, \$1.5 million, on the basis that "EEI spent a
23 significant portion of the \$1.5 million in dues for which DTE is seeking to recover
24 in ways that had no benefit to DTE's customers whatsoever." (page 45). To support
25 her position, she makes several arguments that are based on the belief that a utility-

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1 focused organization like EEI is inherently at odds with customers. For example,
2 DAAO Witness Nichols argues that since a portion of membership dues go toward
3 EEI employee salaries, the organization is prioritizing financial interests over
4 customers (pages 43 and 44). She goes on to describe how EEI's Restore Program,
5 which provides mutual assistance coordination and rapid resources for storm
6 restoration, requires an additional fee beyond base membership dues (pages 44 and
7 45). The supposition is that this additional fee is somehow unreasonable and in
8 conflict with customer interests.

9
10 As it relates to DAAO Witness Nichols' assessment of EEI, her arguments are
11 unsupported and should be rejected. First, DAAO Witness Nichols has not provided
12 any evidence to support her argument that EEI employee compensation is
13 unreasonable compared to similar industry organizations or that such compensation
14 directly relates to the value provided by the organization. As stated in Exhibit A-27
15 Schedule Q1 and further discussed in my revised direct testimony on pages 18-20,
16 "EEI provides strategic business intelligence, and essential conferences and
17 forums. The EEI facilitates collaboration regarding emerging issues facing the
18 industry. The EEI also provides a forum to ask industry related questions to other
19 utilities and provides invaluable resource information about the utility industry and
20 other issues that are important to DTE Electric." Additionally, these services
21 provide the Company with valuable information including "utility benchmarking,
22 best practices, networking and research"¹, which it uses to benefit its customers.
23 Second, the EEI Restore Power program example is merely another unsupported

¹ Leslie Revised Direct Testimony, page 18

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1 assumption and Witness Nichols provides no evidence to suggest that EEI's cost
2 recovery framework for the program is unreasonable.

3

4 **Q8. Does the Company agree with DAAO Witness Nichols' recommendation that**
5 **the Commission should reject expenses related to memberships that either**
6 **fund political advocacy or lack sufficient detail to demonstrate tangible**
7 **customer benefits?**

8 A8. No. As described in my testimony on page 17 and supported by Witness Uzenski,
9 memberships, or portions of memberships, related to lobbying activities are
10 excluded from DTE Electric's revenue requirement. In addition, The Company
11 notes that positions taken by industry organizations, like EEI, do not necessarily
12 reflect the positions of its member companies simply because those companies pay
13 membership dues. In the January 23, 2025 Order in Case No. U-21534, the
14 Commission noted that DTE Electric need not agree with all of an organization's
15 policies to reap benefits for its customers commensurate with the cost of
16 membership.²

17

18 DAAO Witness Nichols' belief that industry organizations, such as EEI, have taken
19 positions that are not in the best interest of customers³ does not negate the benefits
20 of that membership⁴ or provide sufficient justification to disallow the Company's
21 proposed membership dues. In addition, the Company does not have ready access
22 to a detailed list of all activities undertaken by the industry associations of which it
23 is a member. Similarly, the industry associations of which the Company is a

² January 23, 2025 Order in Case No. U-21534, page 243

³ Witness Nichols revised direct testimony, page 43 lines 10-14, page 51 lines 2-5

⁴ The Company provides a list of benefits from corporate members on page 18 of my revised direct testimony and highlights the benefits of its corporate memberships in Exhibit A-27, Schedule Q1

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1 member do not designate the Company's membership dues for a particular purpose
2 or purposes. As such, the Company simply does not have the level of detail
3 suggested by DAAO Witness Nichols. Attempting to compile such information
4 (assuming industry associations have it available) would be costly in terms of the
5 Company's time and resources required, and in addition, DAAO Witness Nichols
6 has not provided any actual evidence that such an undertaking would result in
7 conclusive evidence supporting her position.

8

9 **Q9. Does the Company agree with DAAO Witness Nichols' assertion that it did not**
10 **comply with the disclosure requirements for discretionary memberships set**
11 **forth in Cases Nos. U-21297 and U-21534?**

12 A9. No. To start, the Company did follow the Commission's guidance in both the
13 December 1, 2023 (Case No. U-21297) and January 23, 2025 (Case No. U-21534)
14 Orders. In Case No. 21534, the Company updated Exhibit A-27, Schedule Q1, to
15 capture *specific* customer benefits related to each of its corporate memberships.⁵

16

17 The Company also disagrees that it did not follow the Commission's guidance in
18 its January 23, 2025 Order in Case No. U-21534 directing it to "provide detailed
19 information sufficient to differentiate the benefits of membership in the Center for
20 Energy Workforce, the Human Capital Institute, and The Institute for Corporate
21 Productivity in its next general rate case to avoid duplication of services and
22 benefits".⁶ The Company is only requesting recovery of one human resource
23 membership, The Institute for Corporate Productivity, as noted in my Exhibit A-

⁵ In the January 23, 2025 Order in Case No. U-21534, page 243 the Commission noted that the Company provided additional evidence and improvement over Case No. U-21297

⁶ January 23, 2025 Order in Case No. U-21534, page 466 (Item H)

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1 27, Schedule Q1, and has either terminated or excluded memberships in the Center
2 for Energy Workforce and the Human Capital Institute in this instant case. There
3 were no other recommendations specific to *discretionary* corporate memberships.
4 In addition, as stated in my revised direct testimony on pages 17-18, the Company
5 provided a discussion of actual processes, projects, procedures, or other tangible
6 impacts benefiting the Company's customers that have resulted from
7 *nondiscretionary* corporate memberships.

8

9 It should be noted that DAAO Witness Nichols appears to conflate the
10 Commission's order in Case No. U-21534 related to discretionary and
11 nondiscretionary corporate memberships. The requirements described by Witness
12 Nichols from Case No. U-21534, on page 41 (lines 10-13), are only applicable to
13 *nondiscretionary* memberships. As stated above, the Company has complied with
14 these requirements. However, Witness Nichols is incorrectly arguing, on page 42,
15 that those same requirements are also applicable to the Company's *discretionary*
16 corporate memberships and that the Company did not meet the requirements of the
17 January 23, 2025 Order in Case No. U-21534. This is simply untrue.

18

19 Based on this and the reasons stated above, the Company maintains its proposed
20 recovery of corporate membership dues, including the use of the Exhibit A-27,
21 Schedule Q1 as presented in this case.

22

23 **Q10. Does this conclude your rebuttal testimony?**

24 A10. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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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

REBUTTAL TESTIMONY

OF

AKARSH SHEILENDRANATH

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF AKARSH SHEILENDRANATH

Line
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1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed?**

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

6

7 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
8 **Company (DTE Electric or Company)?**

9 A2. Yes.

10

11 **Purpose of Testimony**

12 **Q3. What is the purpose of your rebuttal testimony?**

13 A3. The purpose of my rebuttal testimony is to respond to certain arguments related to
14 the topics of Disallowance, Regulatory Risk, and the implications on the Cost of
15 Capital, put forth by the Michigan Environmental Council (“MEC”), Natural
16 Resources Defense Council (“NRDC”), and Citizens Utility Board of Michigan
17 (“CUB”), (collectively, “MNC”) witness Douglas B. Jester.

18

19 **Q4. Are you sponsoring any exhibits?**

20 A4. Yes. I am sponsoring the following exhibits.

21 A-57 YY1 RRA Report – Michigan Public Service Commission

22 A-57 YY2 Discovery Response AGDE-9.284c

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1 **Cost Recovery Disallowance and Risk**

2 **Q5. On page 8 of his direct testimony, MNC Witness Jester describes several**
3 **regulatory mechanisms that exist in Michigan to conclude that the Company**
4 **does not operate in a high regulatory risk environment. Do you agree?**

5 A5. Only partially. While I do agree that several of Michigan's regulatory mechanisms
6 serve to improve the timeliness of cost recovery for the Company, other regulatory
7 mechanisms are unfavorable for timely recovery. For example, unlike 59% of the
8 operating companies in Company Witness Nelson's¹ Sample Group, DTE Electric
9 does not have a decoupling or decoupling-like provision. Lack of such provisions
10 increase regulatory risk for the Company relative to sample companies in other
11 jurisdictions that benefit from such provisions. Further, supportive regulatory
12 mechanisms such as the provision to employ a forward-looking test year, electric
13 fuel purchase power adjustment clause, are also available to many of witness
14 Nelson's sample companies operating in other jurisdictions. Overall, access to
15 beneficial regulatory mechanisms in Michigan are availed by many sample
16 companies operating in other jurisdictions. As such, I view Michigan's regulatory
17 risk to be comparable to its peers on balance.

18

19 As MNC Witness Jester notes on page 9, Michigan's regulatory environment is
20 rated "Average/1" by S&P Cap IQ Regulatory Research Associates ("RRA")².
21 Albeit the recent RRA ranking downgrade for the state is instructive, as shown in
22 Exhibit A-57, Schedule YY1. It highlights the importance of rate case outcomes for
23 electric utilities in Michigan and the impact that the Commission's decisions have
24 on the RRA's evaluation of the state's regulatory environment. As I explained in

¹ Company Witness Nelson sponsored the Cost of Capital testimony in this proceeding.

² U-21860 Exhibit A-14, D5.8, p. 2

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1 my response to AGDE-9.284c, Exhibit A-57 Schedule YY2, the RRA downgraded
2 Michigan regulation ranking to Average/1 from Above Average/3 on July 31, 2024.
3 The RRA report (Exhibit A-57, Schedule YY1) explained the downgrade by
4 highlighting that “*the outcomes of certain recent rate proceedings could indicate a*
5 *tightening in the regulatory climate*”. It also noted that the RRA had already placed
6 Michigan on watch following a 2022 rate case decision in which the Michigan
7 Public Service Commission (PSC) authorized DTE Electric an increase in rates that
8 was less than 10% of that requested. It explained that while 2022 case was seen at
9 the time as an anomaly, the two subsequent rate case outcomes, including the
10 Commission’s denial of the Company’s rehearing requests, resulted in the state’s
11 ranking downgrade. I note that the state’s ranking downgrade was decided despite
12 RRA’s consideration of Michigan’s constructive regulatory provisions and despite
13 otherwise generally constructive rate outcomes in recent cases.

14

15 **Q6. MNC Witness Jester states on page 9 that disallowances due to “insufficient**
16 **evidence of reasonableness and prudence, ill-timed spending, or poor planning**
17 **do not increase regulatory risk”. How do you respond?**

18 A6. While I generally agree with MNC Witness Jester’s statement, I note that in
19 proffering this view, Witness Jester expands the taxonomy of the disallowances I
20 discuss in my testimony. My direct testimony does not discuss disallowances
21 associated with investments and expenditures that are deemed not prudent and/or
22 reasonably expected to be judged by the Commission as not prudent to pursue.
23 Rather, I explain and illustrate on pages 16-22 of my direct testimony the adverse
24 financial implications of regulatory risk due to potential future disallowances
25 associated with needed investments and expenditures, such as those required for

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1 grid reliability, upgrading generation fleet, improving service quality, and for
2 meeting policy mandates, such as the clean energy transition. In other words, I
3 discuss the adverse implications on the cost of capital and financial integrity of the
4 Company of a *specific type of disallowance*—one associated with investments and
5 expenditures that are *prudent or expected to be judged as prudent*.
6 Cost recovery disallowances associated with prudent investments do increase
7 regulatory risk. As I explained in my direct testimony on page 5, persistent
8 disallowances increase the uncertainty associated with future cost recovery.
9 Consequently, it would be viewed by investors as contributing to *regulatory risk*.
10 The market-determined cost of capital, as estimated by standard financial models,
11 only account for the *systematic risk* of the sample companies with commensurate
12 [systematic] risk of the subject company. It does not account for additional
13 disallowance risk borne by the Company stemming from the regulatory
14 environment and practices, such as persistent disallowances, specific to the state in
15 which the regulated entity operates.
16
17 When faced with higher regulatory risk (relative to DTE Electric's Sample
18 Companies), investors' *ex ante* expected rate of return on utility's future capital
19 investments will increase. If not adequately addressed through higher authorized
20 rates of return that investors require, the utility will not have a fair opportunity to
21 earn its cost of capital.

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- 1 **Q7. Is there certainty regarding which investments and expenditures the Company**
2 **identifies as necessary to pursue—to address reliability, service quality, or**
3 **policy goals and mandates—would be deemed prudent by the Commission?**
4 **Please also explain how this affects regulatory risk.**
- 5 A7. There is seldom absolute certainty about what the Commission may eventually
6 deem to be a prudent investment and which ones it may not. Utility and the
7 Commission may also disagree about the prudence of certain investments or parts
8 of it. These disagreements may not always be foreseeable and thus, also, are not
9 entirely avoidable. However, it is important to reduce the scope of these “gray
10 areas” in prudence determination and minimize penalizing the Company for public
11 good enhancing investments made in good faith, despite the inherent uncertainties
12 in prudence determinations of investments and expenditures. Many expenditures
13 that the Company forecasts for the bridge year and the forward test year address
14 near-term or immediate needs related to reliability or service issues. Such
15 expenditures may be difficult to avoid or retime after the Commission’s prudence
16 determination. The Company should not be unduly penalized when planning for
17 near-term needs in advance of the test year. Nor should there be overreliance on
18 historical expenditures information to judge the reasonableness of projected
19 expenditures on needed projects that serve to benefit customers. Historical
20 expenditures may reflect severely outdated cost information, thus are not the
21 appropriate benchmark for projected expenditures. Deviations of planned
22 expenditures from historical information thus is not a sufficient reason to disallow
23 cost recovery. When employing the forward test year provision available to
24 Michigan utilities, the Company will not have perfect foresight into the
25 expenditures and their timing to address investments needs two or more years in

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1 the future. Uncertainty related to prudence will remain, but planning for needed
2 grid and related investments may not be optional. They affect reliability and service
3 quality and thus must be pursued despite the prudence risk the Company bears.

4

5 Persistent disallowances of the Company's cost recovery of certain expenditures
6 that are forecasted based on good faith estimation of need and timing of incurrence
7 because of a presumption that some planned projects may eventually be deemed
8 imprudent, or that the Company may not pursue all those planned projects, or it
9 may deviate from its planned schedule, will introduce asymmetric regulatory risk.
10 When faced with such asymmetric regulatory risk, investors will not have a fair
11 opportunity to earn their required return, on average.

12

13 Additionally, because forward test year expenditures and the timing of their
14 incurrences cannot be predicted with certainty when forecasting two years in
15 advance, the regulatory process should seek to balance the risk of disallowances
16 (associated with prudent projects) fairly between the customers and the Company.
17 It is important to recognize that many uncertainties and non-controllables are
18 inherent when the Company forecasts future expenditures for needed projects.
19 Those uncertainties cannot be eliminated even with best quality estimates
20 developed in good faith. In such instances, the preemptive disallowance of planned
21 expenditures, due to presumption of potential cost deviation, is not appropriate. It
22 will increase regulatory risk and investors will demand higher authorized returns to
23 have a reasonable opportunity to earn the market-determined cost of capital.

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1 **Q8. MNC Witness Jester asserts on page 11, lines 5-7 that “Even in instances of**
2 **unavoidable and prudent costs, disallowances can improve earnings quality if**
3 **the costs are not incurred in a timely manner or if the actual expenses deviate**
4 **materially from the estimates”. How do you respond?**

5 A8. It is unclear what witness Jester means by “earnings quality”. In standard financial
6 terminology, earnings quality (or Quality of Earnings), which is not an accounting
7 metric, generally informs about the stability, sustainability, informativeness, and
8 predictability of earnings emanating from the core operations of a business. It
9 appropriately accounts for non-recurring items. Earnings reporting follows the
10 Generally Accepted Accounting Principles (GAAP) accounting requirements.
11 GAAP stipulates that revenue is recognized when services are rendered, or when
12 obligations are satisfied. In regulatory parallels, recording costs as they are incurred
13 along with the associated revenues achieves this. Disallowances of prudent
14 investments because of a presumption that forecasted costs or the timing of planned
15 expenditures can change from initial forecasts does not improve the quality of
16 earnings. It penalizes the Company for imperfect foresight and uncertainties that
17 are difficult to fully resolve, resulting in higher regulatory risk.

18

19 **Q9. MNC Witness Jester suggests on page 14, lines 3-4 that “The typical prudence**
20 **and substantiative regulatory review is already priced in the market-**
21 **determined cost of capital.” Do you agree? Please explain.**

22 A9. No, I do not. This is a misunderstanding of what the cost of capital or the cost of
23 equity measures. The market-determined cost of capital, as estimated by standard
24 financial models employed by Company Witness Nelson, considers only the
25 systematic risk of the comparable proxy group. To the extent that DTE Electric has

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1 higher disallowance risks or if such risks are asymmetric, they are not part of the
2 measured cost of equity. Therefore, it is necessary to either remove such
3 asymmetric risks or alternatively authorize a higher ROE, so that the Company, on
4 average, can expect to earn its authorized ROE (assuming prudent and efficient
5 management).

6

7 **Q10. What was MNC Witness Jester's overall recommendation on page 14-15?**

8 A10. MNC Witness recommends that the Commission reject the Company's argument
9 that disallowances increase regulatory risk and asserts that the Company is not
10 entitled 'to recovery of projected costs without meeting the required standards of
11 evidence'. He also notes that if DTE Electric were to expend any disallowed
12 expenditures, it can seek cost recovery in a future rate case, subject to prudence
13 review. He acknowledges that this can create "some asymmetric risk for investors"
14 but claims that the asymmetric risk borne by the ratepayers would be higher. He
15 also recommends that "the Commission not include an additional premium for
16 DTEE's cost of capital beyond the market-determined cost of capital" which he
17 claims, "already compensates for the typical regulatory review of costs".

18

19 **Q11. How do you respond to Witness Jesters recommendations?**

20 A11. I disagree with these recommendations. As I explained, persistent disallowances of
21 prudently incurred costs do increase regulatory risk and thereby the investors' ex
22 ante expected return and the overall cost capital. MNC Witness Jester's arguments
23 focus largely on imprudent investment and expenditures. As I explained above, the
24 Company projects in good faith future investments and expenditures that are needed
25 and thus, expected to be judged as prudent investments as they serve to improve

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1 reliability, service quality or meet required mandates. The Company will not have
2 perfect foresight of the exact expenditures or the exact timing of incurrence of those
3 expenditures at the time of planning, which begins over two years in advance of the
4 test year. Therefore, some deviations from the planned projects and the timing of
5 actual incurrence should be expected. It is not reasonable to preemptively disallow
6 needed future projects presuming that the Company may not peruse some of those
7 projects (even though it fully plans to) or that the timing of incurrence of planned
8 expenditures might change. It is not reasonable to over-rely on historical
9 expenditure information to judge the reasonableness of future planned expenditures
10 and disallow cost recovery. Doing so penalizes the Company for plans and forecasts
11 made in good faith and increases investors' risk.

12
13 Requiring that the Company seek cost recovery in future rate cases of incurred
14 expenditures on necessary projects (which therefore may not be retimed) does
15 create regulatory lag and offsets some of the very benefits of the forward test year
16 provision designed to better match the timing of cost recovery with incurrence of
17 costs. As, witness Jester acknowledges, it indeed creates asymmetric risks for
18 investors. When faced with asymmetric regulatory risk, investors will not have a
19 fair opportunity to earn their required return, on average, and therefore the
20 authorized return would need to be higher. Contrary to Witness Jester's claim, the
21 market-determined cost of capital considers only the systematic risk of the
22 comparable proxy group. To the extent that DTE Electric has higher disallowance
23 risks or if such risks are asymmetric, the market-determined cost of equity does not
24 compensate adequately for the higher disallowance and asymmetric risk.

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1 **Q12. Please summarize your conclusions.**

2 A12. MNC Witness Jester's arguments focus largely on *imprudent* investment and
3 expenditures. My direct testimony explained the adverse implications of persistent
4 disallowances of *prudently* incurred costs on regulatory risk and on investors' *ex*
5 *ante* expected return and the overall cost capital. As I explained in my direct
6 testimony, illustrating with quantitative examples, persistent disallowances of
7 prudent expenditures increase the Company's regulatory risk. The RRA's recent
8 downgrade of Michigan's regulatory ranking to "Average/1" was in part because
9 of the perceived heightened regulatory risk due to multiple rate case outcomes since
10 2022.

11

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

19

20 It is a misunderstanding that prudence and substantiative regulatory review is
21 accounted for in the market-determined cost of capital. The market-determined cost
22 of capital considers only the systematic risk of the sample group employed to
23 estimate the cost of capital. If DTE Electric has higher disallowance risks than
24 those in the sample, or if such risks are asymmetric, they are not part of the

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1 measured cost of equity. Therefore, it is necessary to either remove such
2 asymmetric risks or alternatively authorize a higher ROE.

3

4 **Q13. What is your overall recommendation?**

5 A13. I recommend that the Commission look to improve regulatory processes that reduce
6 the risk of persistent future disallowances associated with the necessary
7 investments and expenditures the Company will need to undertake over the coming
8 years to reinforce its aging electric distribution grid, upgrading its power generation
9 fleet, developing utility-scale energy storage systems, and improving service
10 quality to serve a growing demand for power. One lever the Commission has for
11 accomplishing this, while also ensuring managerial discipline and protecting
12 customers, is further support for the IRM. Approval of the Company's proposed
13 2027-2029 IRM described by Company Witness Willis and Staff Witness Boutet's
14 proposal to include \$200 million of 2026 PTMM investment in the 2026 IRM
15 would serve to realize greater managerial discipline and customer protection. Doing
16 so will minimize regulatory lag and asymmetric risks. If not, I recommend the
17 Commission recognize that a higher authorized rate of return will be necessary to
18 compensate for the corresponding higher regulatory risk resulting from persistent
19 cost recovery disallowances.

20

21 **Q14. Does this conclude your rebuttal testimony?**

22 A14. 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

REBUTTAL TESTIMONY

OF

TIMOTHY S. LYONS

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF TIMOTHY S. LYONS

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1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed?**

3 A1. My name is Timothy S. Lyons. My business address is 1 Speen Street, Suite 150,
4 Framingham, Massachusetts 01701. I am a Partner with ScottMadden, Inc.

6 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
7 **Company (“DTE Electric” or the “Company”)?**

8 A2. Yes. I filed direct testimony in this proceeding on behalf of the Company before
9 the Michigan Public Service Commission (“MPSC” or “Commission”).

10

11 **Purpose of Testimony**

12 **Q3. What is the purpose of your rebuttal testimony?**

13 A3. The purpose of my rebuttal testimony is to respond to certain positions taken by
14 Witness Durfee on behalf of the MPSC’s Energy Operations Division (“Staff”),
15 Witness Coppola on behalf of the Attorney General (“AG”), Witness Jester of 5
16 Lakes Energy on behalf of Michigan Environmental Council (“MEC”), National
17 Resources Defense Council (“NRDC”) and Citizens Utility Board of Michigan
18 (“CUB”), (collectively “MNC”), and Witness York on behalf of the Association of
19 Businesses Advocating Tariff Equity (“ABATE”),

20

21 **Q4. Are you sponsoring any exhibits in this proceeding?**

22 A4. Yes

<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>

A-40	EE1	Staff Discovery Response 2.1 and 2.2

Line
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1 **Summary of Testimonies**

2 **Q5. What are Staff Witness Durfee's recommendations related to Base Capital?**

3 A5. Staff Witness Durfee's recommendations are summarized below.

- 4 • Remove historical inflation adjustments from the following Base Capital
- 5 categories:
- 6 ○ Emergent Replacements¹
- 7 ○ Customer Connections, Relocations, and Other²

8

9 **Q6. What are AG Witness Coppola's recommendations related to Base Capital**
10 **and Storm Restoration?**

11 A6. AG Witness Coppola's recommendations are summarized below.

- 12 • Reject the Company's utilization of constant dollar averaging ("CDA") in
- 13 developing projections of some categories of capital and operations and
- 14 maintenance ("O&M") expenditures.³
- 15 • AG Witness Coppola's recommendation applies to the following Base Capital
- 16 expenditures:
- 17 ○ Emergent Replacements⁴
- 18 ○ Customer Connections, Relocations & Other⁵
- 19 • AG Witness Coppola's recommendation applies to the following O&M
- 20 expenditures:
- 21 ○ Storm Restoration⁶

¹ Direct testimony of Witness Durfee, p. 5

² Id.

³ Direct testimony of Witness Coppola, p. 24

⁴ Id.

⁵ Id., p. 27

⁶ Id., p. 109

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1 **Q7. What are MNC Witness Jester's recommendations related to Base Capital and**
2 **Storm Restoration expenses?**

3 A7. MNC Witness Jester's recommendations are summarized below.

- 4 • Utilize uninflated historical average with inflation to future test year.
- 5 • MNC Witness Jester's recommendation applies to the following capital
- 6 expenditures:
 - 7 ○ Distribution Capital⁷
- 8 • MNC Witness Jester's recommendation applies to the following O&M
- 9 expenditures:
 - 10 ○ Storm Restoration⁸

11

12 **Q8. What are ABATE Witness York's recommendations related to Base Capital?**

13 A8. ABATE Witness York's recommendations are summarized below.

- 14 • Remove historical inflation adjustments for the following Base Capital
- 15 categories:
 - 16 ○ Emergent Replacements⁹
 - 17 ○ Customer Connections, Relocations, and Other¹⁰

18

19 **Q9. Before providing the Company's response to the referenced testimonies, would**
20 **you please summarize the benefits of utilizing CDA to project future costs?**

21 A9. Yes. As discussed on page 7 of my direct testimony, CDA provides for a more
22 accurate forecast of future costs and maintains the purchasing power of being able
23 to purchase the same units of materials and labor over time.

⁷ Direct testimony of Witness Jester, p. 23

⁸ Id., p. 17

⁹ Direct testimony of Witness York, p. 27

¹⁰ Id.

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1 Specifically, CDA ensures that as price levels increase over time due to inflation,
2 cost forecasts reflect the higher price of goods and services purchased in the future.
3 The same principle would apply if price levels decreased over time due to deflation.
4 Cost forecasts would need to reflect the lower price of goods and services purchased
5 in the future.

6

7 **The Company's response to Staff Witness Durfee**

8 **Q10. Does the Company agree with Staff Witness Durfee's recommendation to**
9 **remove the inflation adjustment from historical costs?**

10 A10. No. Staff Witness Durfee's recommendation is based on an assessment that "the
11 Company did not provide a convincing argument that it is necessary to inflate the
12 years within the five-year average for Emergent Replacements or the three-year
13 average for Customer Connections, Relocations, and Other."¹¹ Staff Witness
14 Durfee further states, "There is also still not a consistent trend upward within these
15 programs."¹²

16

17 As primary support, Staff Witness Durfee referenced the Commission's decision in
18 the Company's most recent rate case, stating "The Commission found that DTE has
19 not provided a convincing argument that it is necessary to inflate the years within
20 the five-year average."¹³

21

22 **Q11. Do you agree the Company did not provide a convincing argument in direct**
23 **testimony that it is necessary to inflate costs within the five-year average for**

¹¹ Direct testimony of Witness Durfee, p. 5

¹² Id.

¹³ Id, referencing the January 23, 2025, Order in Case No U-21534, pg. 73.

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1 **Emergent Replacements or the three-year average for Customer Connections,**
2 **Relocations, and Other?**

3 A11. No. My direct testimony was specifically written for the Company to address the
4 Commission's Order which states,

5 "...[the Commission's] response to the use of constant dollar averaging
6 might be different if the evidence showed that these expenditure categories
7 are both volatile and consistently trending upwards."¹⁴

8

9 **Q12. Did the Company file evidence in this proceeding that responded to the**
10 **Commission's suggestion to demonstrate how the expenditure categories were**
11 **both volatile and consistently trending upward?**

12 A12. Yes. The Company provided evidence on pages 12 through 17 of my direct
13 testimony that responded to the Commission's suggestion to demonstrate how the
14 expenditure categories were both volatile and consistently trending upward. This
15 evidence is further outlined below.

16

17 **Q13. What specific evidence did the Company file in this proceeding to demonstrate**
18 **how the expenditure categories were volatile?**

19 A13. In response to the Commission's concern regarding downward trends for Emergent
20 Replacement (storm) costs, the Company provided evidence showing year-over-
21 year fluctuations in Emergent Replacement (storm) costs can be explained by year-
22 over-year fluctuations in customer interruptions and restorations.¹⁵

¹⁴ January 23, 2025 Order in Case No. U-21534, pg. 73.

¹⁵ See Tables 2 and 3 presented in Direct testimony of Timothy S. Lyons, p. 12

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1 The Company also provided evidence on page 12 of my testimony that shows that
2 Emergent Replacement costs are volatile.¹⁶

3

4 **Q14. What evidence did the Company file in this proceeding to show how the**
5 **expenditure categories' costs were consistently trending upward?**

6 A14. The Company provided evidence on page 14 of my direct testimony showing costs
7 for materials commonly replaced as part of Emergent Replacements have increased
8 consistently over the past several years.

9

10 For example, the Company's evidence showed that overhead and underground
11 transformer costs have increased by 318.0 percent and 468.0 percent, respectively,
12 since 2020. Wood poles have increased by 114.0 percent since 2020. Finally,
13 underground cables and overhead conductors have increased by 68.0 percent and
14 40.0 percent, respectively, since 2020.¹⁷

15

16 **Q15. Did the Company provide evidence showing labor costs were also consistently**
17 **trending upward?**

18 A15. Yes. The Company provided evidence on page 16 of my direct testimony showing
19 contract labor rates have increased over the past several years based on the
20 Company's collective bargaining agreement.¹⁸ In addition, please refer to
21 Company Witness Hill's direct (page 11) and rebuttal testimony (Rebuttal Issue
22 #2).

¹⁶ Id., Table 2

¹⁷ Id., Table 4, p. 14

¹⁸ Id., Figure 2, p. 16

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1 **Q16. Did Staff Witness Durfee consider the evidence provided by the Company in**
2 **my direct testimony?**

3 A16. No. Staff Witness Durfee states in discovery response 2.1(b) (Exhibit A-40,
4 Schedule EE-1):

5 “Staff Witness Durfee did not consider the reduction in volume of work and
6 expenditures in 2020 and 2022 due to the reduction in customer
7 interruptions as an explanation for the reduction in Emergent Replacement
8 costs in 2020 and 2022.”

9 Staff witness Durfee states in Discovery response 2.2(c) (Exhibit A-40, Schedule
10 EE-1)::

11 “Staff Witness Durfee did not consider the cost increase related to materials
12 and labor as presented by witness Lyons.”

13

14 **The Company’s response to AG Witness Coppola**

15 **Q17. Does the Company agree with AG Witness Coppola’s recommendation to**
16 **reject the Company’s inflation adjustment to historical costs for Emergent**
17 **Replacements and Customer Connections, Relocations and Other?¹⁹**

18 A17. No. As stated earlier, the Company provided evidence in direct testimony to
19 address the Commission’s suggestion to demonstrate how the expenditure
20 categories were both volatile and consistently trending upward.

21

22 **Q18. As an initial matter, is the Company seeking to retroactively recover some**
23 **additional inflation-related costs through its constant dollar averaging**
24 **adjustments – a point raised in AG Witness Coppola’s testimony?²⁰**

¹⁹ Direct Testimony of Witness Coppola, p.24

²⁰ Id., p. 20

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1 A18. No. As discussed in pages 8 through 10 of my direct testimony, the Company's
2 use of CDA is only to develop more accurate cost *forecasts*. Costs are more
3 accurately forecasted when the impact of inflationary trends has been normalized.
4 This is accomplished by converting historical (nominal) dollar values to constant
5 (current) dollar values. CDA applies to the forecasted costs and does not recover
6 shortfalls in prior cost recovery. Consequently, the Company's use of CDA does
7 not retroactively recover inflation-related costs.

8

9 The Commission has already acknowledged that CDA would not result in a
10 duplication of inflationary costs, stating:

11 "The Commission notes that no year within the 2018-2022 five-year
12 average period nor any year in the bridge or test periods is actually inflated
13 twice"²¹

14

15 **Q19. Do you agree with AG Witness Coppola's statement that "adjusting historical**
16 **costs that already reflect the inflation in that year with a general inflation**
17 **factor that occurred in a subsequent year has no relevance and is simply an**
18 **artificial exercise to increase the amount of requested rate increase"?²²**

19 A19. No. Adjusting historical costs with a general inflation factor that occurs in
20 subsequent years is highly relevant because it reflects the change in price levels
21 from the initial year to the subsequent years. If for example a product costs \$100
22 in the initial year, then the price level of that product would be \$100. If in the
23 subsequent year there is a general inflation factor of 5.00 percent, then the price
24 level of the product increases to \$105. Thus, tracking general inflation identifies

²¹ Michigan PSC, Case No. U-21534, Order, January 23, 2025, p. 73

²² Direct Testimony of Witness Coppola, pp. 22-23

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1 the price level of the product in subsequent years. If inflation adjustment was not
2 applied, the assumption for price levels would remain at \$100, ignoring the impact
3 of general inflation. This would understate the cost of the product in future years.

4
5 **Q20. What other concerns were expressed by AG witness Coppola?**

6 A20. Other concerns expressed by AG witness Coppola included:

- 7 • The Company provided no evidence the Department of Defense (“DoD”)
8 uses CDA to justify increases in supplier payments.²³
- 9 • The Company provided no evidence CDA is used in business transactions
10 with financial consequences.²⁴
- 11 • Some of the utility cases presented are based on the utility proposal with no
12 clear indication the commissions accepted CDA. In addition, some of the
13 cases were settled and not litigated.²⁵
- 14 • The Company provided primarily a theoretical discussion but offers very
15 little practical application.²⁶

16
17 **Q21. What is the Company’s response to AG Witness Coppola’s concern regarding**
18 **the DoD’s use of CDA to justify increases in supplier payments?**

19 A21. The purpose of the DoD reference was to demonstrate that the DoD utilizes CDA
20 to provide accurate information and realistic estimates of costs for DoD acquisition
21 programs. The DoD states that “independent and sound cost estimates are vital for
22 effective acquisition decision making and oversight. Cost estimates also support
23 efficient and effective resource allocation decisions throughout [their] planning,

²³ Id., p. 21

²⁴ Id.

²⁵ Id., p. 22

²⁶ Id., p. 20

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1 programming, budgeting and execution process.”²⁷ Furthermore, in routine
2 practice, CDA is used to support DoD cost analysis.²⁸

3 The ‘U.S. Department of Defense Inflation and Escalation Best Practices
4 for Cost Analysts’ explains:

5 “To properly estimate the cost of a new system, the analyst needs to
6 understand the relationships among historical costs, technical
7 characteristics, and quantity orders. In order to derive realistic relationships,
8 and ultimately estimate the final cost, the analyst will have to account for
9 the effects of persistent underlying cost changes that occur regardless of
10 individual programmatic decisions, specifically inflation and escalation.”²⁹

11 The ‘Army Cost Analysis Manual’ also discusses the importance of accounting for
12 inflation when developing future cost estimates based on historical costs. The
13 Manual explains:

14 “After an analyst collects historical data, the analyst needs to determine if
15 any adjustments should be made prior to estimation. The most common
16 adjustments an analyst makes are those based on inflation. **Constant**
17 **year/base year values do not show the changing spending power of the**
18 **dollar over time** whereas current year/then year values reflect the effect of
19 inflation. **In order to use a varied data set, an analyst must ensure that**
20 **a consistent base year is used in order to determine the true cost**
21 **impacts of inputs.**

²⁷ DoD Instruction 5000.73, Cost Analysis Guidance and Procedures, pdf page 5, [Access Link](#)

²⁸ Id., page 12, where DoD states: “ICE, CCE, and CCP memorandums and reports must report costs in constant year dollars and then year dollars in accordance with CAPE’s Inflation and Escalation Best Practices for Cost Analysis...”

²⁹ U.S. Department of Defense Inflation and Escalation Best Practices for Cost Analysts, December 2021, p. 5, [Access Link](#)

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1 Inflation is relevant because the buying power of the United States
2 (US) Dollar is inconsistent over time. For example, one gallon of milk
3 purchased in the US in 1950 would cost approximately \$0.82. The same
4 end item – one gallon of milk – purchased in the US in 1996 would cost
5 approximately \$3.12. The end item is the same and the unit of measure is
6 “the US Dollar,” however, the value of the US Dollar changed from 1950
7 to 1996 such that **more “Dollars” are needed to acquire the same end**
8 **item at the later point in time.** This devaluation of currency over time (or,
9 inversely, the increasing cost of goods and services over time) is referred to
10 as “inflation,” and it needs to be considered in the cost estimating
11 process.”³⁰ [**Emphasis added**]

12 In a similar manner, the Company utilizes CDA to account for the changing value
13 of the US Dollar and determine historical year cost of goods and services in current
14 year ‘real’ terms, which then becomes the basis for cost forecasting.

15

16 **Q22. What is the Company’s response to AG Witness Coppola’s concern that**
17 **Company provided no evidence to support that CDA is used in business**
18 **transactions with financial consequences?**

19 A22. CDA is not used in business transactions. CDA is used to accurately forecast costs
20 when such forecasts are developed based on historical cost data.

21

22 The importance of this normalization step is recognized by the Association for the
23 Advancement of Cost Engineering (“AACE”) International, a recognized authority

³⁰ 2020 Army Cost Analysis Manual, p. 5-21, 5-22, [Access Link](#)

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1 on cost engineering across a wide range of industries. AACE notes the importance
2 of inflation-adjusting historical costs when estimating future costs:

3 “Routine estimating cost data maintenance includes updating the costs of
4 equipment, material, labor, etc., needed to estimate the future cost of a
5 project or to bring historical costs to the present. This is because cost
6 estimating, generally, is done in today’s dollars and then escalated to the
7 time when the project will be executed.”³¹

8

9 **Q23. What is the Company’s response to AG Witness Coppola’s concern regarding**
10 **evidence to support constant dollar averaging was accepted by other state**
11 **commissions?**

12 A23. Constant dollar averaging is utilized by California utilities. For example, San Diego
13 Gas and Electric’s use of CDA of historical costs was accepted by the California
14 Public Utilities Commission.³² The decision states:

15 “With respect to the proposed methodology to calculate the adjustment for
16 capital additions, we find the Applicant’s proposal to escalate capital additions
17 by major plant category for each year to PTY dollars based on Global Insight
18 Indices to be reasonable...Using this methodology, recorded and forecasted
19 costs would be escalated to 2019 dollars and then averaged while additions for
20 2020 to 2021 are determined by escalating the seven-year average using Global
21 Insights indices.”³³

³¹ AACE Source Blog, Understanding and Estimating Escalation: Part Two, [Access Link](#)

³² CPUC 19-09-051, Decision, pdf page 740, [Access Link](#)

³³ Id

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1 **Q24. Do you agree with AG Witness Coppola that PECO's approval was**
2 **uncontested since it was through a settlement?**

3 A24. No. While PECO's rate case concluded in a settlement, the parties to the
4 proceeding would have had the opportunity to examine PECO's approach to
5 CDA.³⁴ Importantly, PECO's use of CDA has been approved consistently in
6 settlement agreements over the past decade in 2015,³⁵ 2018,³⁶ 2021,³⁷ and 2024.³⁸

7
8 **Q25. Did Witness Coppola recommend any other adjustments related to CDA?**

9 A25. Yes. AG Witness Coppola removed CDA from his Storm Restoration O&M
10 expense calculation. He stated on page 109 "I used the actual historical expenses
11 [for Storm Restoration O&M] while the Company applied the same Constant
12 Dollar Averaging adjustments to historical amounts that it used for Emergent
13 Replacements capital expenditures." He goes on to say on lines 12-14 that "As
14 discussed in the Capital Expenditures-Distribution section of my testimony, the
15 constant dollar averaging approach and the normalization amount calculated by the
16 Company should be rejected."

17

18 **Q26. Does the Company agree with AG Witness Coppola's recommendation to**
19 **reject the Company's inflation adjustment to historical costs for Storm**
20 **Restoration?**

³⁴ Pennsylvania PUC, Docket No. R-2024-3046931, Opinion and Order, p. 2, [Access Link](#)

³⁵ Pennsylvania PUC, Docket No. R-2015-2468981, Direct Testimony of Shuo Yin, Exhibit SY-3, Schedule D-13, pdf page 1107, [Access Link](#)

³⁶ Pennsylvania PUC, Docket No. R-2018-3000164, Direct Testimony of Benjamin S. Yin, Exhibit BSY-1, Schedule D-13, pdf page 206, [Access Link](#)

³⁷ Pennsylvania PUC, Docket No. R-2021-3024601, Direct Testimony of Michael J. Trzaska, Exhibit MJT-1, Schedule D-13, pdf page 228, [Access Link](#)

³⁸ Pennsylvania PUC, Docket No. R-2024-3046931, Direct Testimony of Michael J. Trzaska, Exhibit MJT-2, Schedule D-13, pdf page 344, [Access Link](#)

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1 A26. No. As stated earlier, the Company provided evidence in direct testimony to
2 support the use of CDA. In addition, the Company has addressed the Commission's
3 suggestion to demonstrate how the materials and labor expenditure categories were
4 both volatile and consistently trending upward. Refer to Company Witness
5 Kryscynski for additional information.

6

7 **The Company's response to MNC Witness Jester**

8 **Q27. Does the Company agree with MNC Witness Jester's recommendation to**
9 **remove the Company's inflation adjustment of historical costs?**

10 A27. No. As stated earlier, the Company provided evidence in direct testimony that
11 addressed the Commission's suggestion to demonstrate how the expenditure
12 categories were both volatile and consistently trending upward.

13

14 **Q28. What is the basis for the MNC witness Jester's recommendation?**

15 A28. MNC Witness Jester's recommendation is based on the following
16 concerns/arguments:

- 17 • Nominal dollar averaging does not lose purchasing power over time due to
18 inflation in a cumulative sense. Nominal cost averaging over multiple rate
19 cases will produce a higher cost average.³⁹
20 • An upward trend in Distribution Operations labor rates does not justify
21 constant dollar averaging⁴⁰

³⁹ Direct Testimony of Witness Jester, pp. 16-17

⁴⁰ Id., p. 17

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- 1 • PECO, which has previously utilized CDA to forecast storm costs,
2 recovered storm costs higher than actual costs by \$15.0 million (or 4.2
3 percent) during 2016-2023 period.⁴¹
- 4 • Given the significant year-to-year variations in actual storm costs
5 compared to projections, CDA is not a suitable method for producing
6 reliable estimates.⁴²
- 7 • Two out of three example utilities that utilize constant dollar average were
8 under Performance-Based Ratemaking frameworks.⁴³

9

10 **Q29. Do you agree with MNC Witness Jester's argument that nominal dollar**
11 **averaging does not lose purchasing power over time in a cumulative sense?**

12 A29. No. Nominal dollar averaging understates the real level of costs when older year
13 costs are included without inflation adjustment. As discussed earlier in the
14 testimony, inflation erodes the comparability of dollar value over time. Averaging
15 historic nominal costs combines lower-cost years with more recent higher-cost
16 years, artificially pulling the average down.

17

18 CDA corrects for this by restating historic costs in terms of current year dollar value
19 before averaging. This ensures that costs from all years reflect a consistent
20 purchasing power and that the average is representative of the real level of costs
21 needed to provide service.

⁴¹ Id., pp. 17-18

⁴² Id., pp. 19-20

⁴³ Direct Testimony of Witness Jester, p. 23

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1 Without this adjustment, the costs would be understated. Witness Jester states that
2 nominal averaging over multiple rate cases will produce a higher cost average.
3 However, the nominal average cost would continue to be understated in future rate
4 cases as it would not reflect the 'real' dollar value of historical costs.

5

6 **Q30. Do you agree with MNC witness Jester's concern regarding over-recovery of**
7 **storm costs by PECO?**

8 A30. No. The over- or under-recovery of storm costs is driven by the unpredictability of
9 storm events, not by whether the Company uses nominal or CDA. Both approaches
10 rely on historical data, and neither can eliminate the natural volatility of weather.
11 CDA simply restates past costs in today's dollars, ensuring a fair comparison across
12 years. Witness Jester's calculation does support the earlier point that storm costs
13 are volatile, as shown in Figure 2 (below). The Figure shows significant volatility
14 in actual storm costs between 2016 and 2023.
15 Regarding cost recovery, the Figure shows in the most recent 6 years (2018-2023)
16 PECO has recovered less revenues from rates than costs.

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1

Figure 1 PECO Rate Allowance vs. Actual Expenses ^{44,45}

Year	Actual Storm		Variance (\$MM)	Variance (%)
	Rate Allowance (\$MM)	Damage Expense (\$MM)		
2016	46	16	30	187.5%
2017	46	9	37	411.1%
2018	46	64	(18)	(28.1%)
2019	44	36	8	22.2%
2020	44	115	(71)	(61.7%)
2021	44	54	(10)	(18.5%)
2022	51	22	29	131.8%
2023	51	41	10	24.4%
Average				83.58%
Total (2016-2023)	\$ 372	\$ 357	\$ 15	4.20%
Total (2018-2023)	\$ 280	\$ 332	\$ (52)	(15.7%)

2

3 **Q31. Do you agree with MNC witness Jester's concern that the work varies too**
4 **significantly to justify the upward trend in costs?**

5 A31. No. As stated on page 14 of my direct testimony, the materials most commonly
6 replaced during Emergent Replacements (storm), such as transformers, poles, and
7 wires, have demonstrated substantial increases since 2020. In addition, as stated
8 on pages 15 and 16 of my direct testimony, labor costs have similarly demonstrated
9 substantial increases since 2020. Also refer to Company Witness Hill's rebuttal
10 testimony Rebuttal Issue #2.

11

12 **Q32. Do you agree with MNC witness Jester's concern that given the significant**
13 **year-to-year variations in actual storm costs compared to projections, constant**
14 **dollar averaging is not a suitable method for producing reliable estimates?**

15 A32. No. As discussed earlier, the year-to-year variation in storm costs reflects the
16 inherent unpredictability of weather events, not the methodology used to calculate

⁴⁴ Id., p. 18

⁴⁵ Pennsylvania PUC, Docket No. R-2024-3046931, Direct Testimony of Michael J. Trzaska, Table 1, pdf page 163, [Access Link](#)

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1 historical averages. Whether one applies a nominal average or constant dollar
2 average, the underlying volatility remains. CDA does not increase or decrease that
3 volatility. It simply restates historical storm costs in terms of current purchasing
4 power so that the historic costs can be compared fairly across years.

5

6 **Q33. Do you agree with MNC witness Jester's concern that two of the three Utilities**
7 **utilizing CDA for capital additions were under Performance Based**
8 **Ratemaking ("PBR") plans?**

9 A33. No. The importance of utilizing CDA of historical costs is relevant and important
10 regardless of the ratemaking mechanisms. The purpose of CDA is to restate
11 historical capital expenditures in terms of current purchasing power to develop a
12 consistent, inflation-adjusted basis for projecting future costs. That principle
13 applies regardless of the ratemaking structure.

14

15 **The Company's response to ABATE Witness York**

16 **Q34. Does the Company agree with ABATE Witness York's recommendation to**
17 **remove the Company's inflation adjustment of historical costs Emergent**
18 **Replacements and Customer Connections, Relocations and Other?**

19 A34. No. As stated above, the Company provided evidence in direct testimony that
20 addressed the Commission's suggestion to demonstrate how the expenditure
21 categories were both volatile and consistently trending upward.

22

23 **Q35. What is the basis for the ABATE Witness York's recommendation?**

24 A35. ABATE Witness York's recommendation is based on the following
25 concerns/arguments:

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- 1 • The uninflated five-year historical average recognizes both 1) increases in
2 material and labor costs and 2) uncertainty around the volume of work that
3 will be required⁴⁶

4

5 **Q36. Do you agree with ABATE Witness York's argument that the uninflated**
6 **historical average recognizes increased material/labor costs, and uncertainty**
7 **around work volume?**

8 A36. No. As stated in the example earlier, the uninflated historical average does not
9 account for increases in material/labor costs over time due to inflation.

10

11 **Q37. Does this conclude your rebuttal testimony?**

12 A37. Yes, it does.

⁴⁶ Direct Testimony of Witness York, p. 26; it should be noted that Witness York applies the same logic to Customer Connections, Relocations and Other on, p. 27

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

REBUTTAL TESTIMONY

OF

BILL CHIU

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF BILL CHIU

Line
No.

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1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed.**

3 A1. My name is Bill Chiu. My business address is One Energy Plaza, Detroit, Michigan,
4 48226 and I am employed by DTE Electric Company.

6 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
7 **Company (DTE Electric or Company)?**

8 A2. Yes.
9

10 **Purpose of Testimony**

11 **Q3. What is the purpose of your rebuttal testimony?**

12 A3. The purpose of this testimony is to rebut certain positions of:

- 13 • Michigan Public Service Commission (MPSC or Commission) Staff (Staff)
- 14 Witness Nicholas M. Evans and Witness Jing Shi.
- 15 • Attorney General (AG), Michigan Environmental Council (MEC), Natural
- 16 Resource Defense Council (NRDC), collectively AG-MN Witness Paul
- 17 Alvarez
- 18 • AG-MN Witness Dennis Stephens
- 19 • Association of Businesses Advocating Tariff Equity (ABATE), Witness
- 20 Jessica A. York
- 21 • Michigan Environmental Council (MEC), Natural Resources Defense
- 22 Council (NRDC), and Citizens Utility Board of Michigan (CUB),
- 23 collectively referred to as MNC Witness Douglas B. Jester
- 24 • Natural Resources Defense Council (NRDC) and Citizens Utility Board of
- 25 Michigan (CUB), collectively referred to as NRDC-CUB Witness Richard
- 26 J. Bunch

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- 1 • The Ecology Center, The Environmental Law & Policy Center, Union of
- 2 Concerned Scientists, and Vote Solar (CEO) Witness Curt Volkmann
- 3 • CEO Witness Boratha Tan
- 4 • CEO Witness William Kenworthy
- 5 • The Michigan Municipal Association for Utility Issues and The Michigan
- 6 Coalition to Protect Public Rights-of-Way (MI-MAUI), Witness Peter
- 7 Schultz

8

9 **Q4. Are you sponsoring any exhibits in this proceeding?**

10 A4. Yes. I am sponsoring the following exhibits:

11	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
12	A-43	HH1	Reliability Workpaper
13	A-43	HH2	Form EIA-861_Reliability_2021
14	A-43	HH3	IEEE 2025 Benchmark Results
15	A-43	HH4	SAIFI 2014-2024
16	A-43	HH5	Discovery Response MNSCDE-3.32h
17	A-43	HH6	Discovery Response MNSCDE-1.8b

18

19 **Q5. How is your testimony organized?**

20 A5. My testimony is organized around several key themes that emerged across the

21 witnesses representing various stakeholder groups. For each topic area listed in the

22 Table of Contents, I will provide a detailed discussion that addresses specific

23 inaccuracies and/or erroneous assumptions presented in their testimony. I will also

24 explain why certain recommendations made by these witnesses should not be

25 adopted by the Commission.

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1 **Rebuttal Issue 1: Capital Investments Lead to Improved Reliability – When We**
2 **Invest, It Works.**

3
4 **Q6. AG-MN Witness Alvarez claims that the Company's distribution capital**
5 **investments have not improved the Company's reliability.¹ What concerns**
6 **does Witness Alvarez express regarding the Company's historic reliability**
7 **investments?**

8 A6. Witness Alvarez expresses the concern that capital investments in the Company's
9 distribution grid are not improving reliability; that Michigan's regulated utilities
10 performed in the bottom quartile of U.S. investor-owned utilities.

11

12 **Q7. Does the Company agree with these claims?**

13 A7. No. His claims are not supported by a comprehensive review of reliability data and
14 misrepresent the positive reliability impacts of the Company's strategic
15 investments.

16

17 **Q8. What metrics does AG-MN Witness Alvarez rely on in taking the position that**
18 **reliability has not improved?**

19 A8. Witness Alvarez primarily relies on Figures 1 and 2 of his direct testimony.

- 20 • Figure 1 (page 7) presents 2023 System Average Interruption Duration
21 Index (SAIDI) without Major Event Days (MED), commonly referred to
22 as SAIDI Ex-MED data.

¹ Direct Testimony of Witness Alvarez, page 5, lines 1-3; pages 7-8, lines 10-10; pages 8-9, lines 12-10.

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- 1 • Figure 2 (page 8) includes both SAIDI with MEDs, commonly referred to
2 as SAIDI all-weather, and SAIDI Ex-MED values spanning the years
3 2014-2024.

4 For context, SAIDI is a standard reliability metric used by electric utilities to
5 measure the average total duration of power interruptions experienced by customers
6 over a given period, typically expressed in minutes.

- 7 • SAIDI without MED (Ex-MED) excludes outlier events to provide a more
8 normalized view of system performance.

- 9 • SAIDI with MED (all-weather) reflects all outage events, including those
10 caused by extreme weather or other major disruptions.

11 Notably, the 2021 SAIDI value for DTE Electric, as presented in Figure 2 of
12 Witness Alvarez's testimony, is incorrect, which calls into question the validity of
13 the comparison. The error in Witness Alvarez's testimony is addressed in response
14 to Question 10 below.

15

16 **Q9. Does Witness Alvarez's Figure 1 appropriately reflect the Company's trends**
17 **in reliability?**

18 A9. No. Figure 1 in Alvarez's testimony is misleading because it only includes a single
19 data point of reliability metric with the 2023 SAIDI Ex-MED data. While this
20 metric appropriately excludes the outlier weather event days when comparing
21 utilities with varying weather-related impacts, relying on data from a single year
22 fails to capture a trend or reflect the cumulative impact of capital investments.
23 Reliability performance should be evaluated over multiple years to identify trends.
24 As shown in Figure 1 below, the Company's multi-year SAIDI Ex-MED data
25 demonstrates progress, supporting the effectiveness of its strategic investments.

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1 Relying on a single year of data distorts Witness Alvarez's analysis and undermines
2 its credibility.

3

4 The fact is the Company's reliability performance has improved. As I noted in my
5 direct testimony on page 11, a combination of the reliability capital improvements
6 in the grid and less extreme weather resulted in a nearly 70% decrease in outage
7 duration times between 2023 and 2024.² Looking back further in recent history,
8 electric outages decreased by 14% and the amount of time customers were without
9 power decreased by 38% in 2024 compared to the five-year average (2019 to 2023).

10 This fact is further corroborated by CEO Witness Volkmann in his direct
11 testimony.³ Moreover, Witness Alvarez focuses exclusively on SAIDI and omits
12 other key metrics such as System Average Interruption Frequency Index (SAIFI),⁴
13 which are essential to understanding overall system reliability. This is just one
14 example that highlights concerns regarding the inaccuracy and the lack of analytical
15 rigor of Witness Alvarez's direct testimony.

16

17 **Q10. Why does the Company believe that Figure 2 on page 8 of Witness Alvarez's**
18 **direct testimony is misleading and inaccurate?**

19 A10. Figure 2 of Alvarez's testimony is misleading because it combines SAIDI with
20 Major Event Days (SAIDI All-Weather) data and SAIDI excluding Major Event
21 Days (SAIDI Ex-MED) data on the same graph. Given the nearly "order of
22 magnitude" difference in values with and without MED, the scale masks the

² DTE Electric's reliability performance in terms of All-Weather SAIDI is 1542 minutes for 2023 and 483 minutes for 2024; All-Weather SAIFI is 1.72 for 2023 and 1.25 for 2024.

³ Direct Testimony of Witness Volkmann, Page 8, Lines 6-9.

⁴ System Average Interruption Frequency Index (SAIFI) represents the average number of times a customer experiences an outage during the year. Refer to U-21860 Exhibit A-43 Schedule HH4 - SAIFI 2014-2024.

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1 downward trend of SAIDI Ex-MED. Additionally, as noted above, the SAIDI Ex-
2 MED value for the year 2021 shown in Figure 2 is simply not correct. Witness
3 Alvarez's chart reports a SAIDI Ex-MED of 239 for 2021, whereas the correct
4 value is 135.6⁵, an error that portrays worse reliability performance with a
5 difference of over 100 minutes, or 76%. This same graph with incorrect
6 information also appeared in Witness Stephens' testimony (Figure 1, page 8) where
7 he draws a similar erroneous conclusion that the Company's capital expenditures
8 have not been effective at improving DTE Electric's reliability.

9
10 Exhibit A-43 Schedule HH1 - Reliability Workpaper includes Witness Alvarez's
11 workpaper with the details behind Figure 2 in his direct testimony and shows both
12 the incorrect data and the corrected 2021 SAIDI data. Exhibit A-43 Schedule HH1
13 also presents a revised graph that excludes all-weather data, offering a clearer view
14 of the Company's SAIDI Ex-MED reliability trend.

15

16 **Q11. Looking at an even longer term, what does the Company's SAIDI Ex-MEDs**
17 **data reflect for the years 2015 through 2024, and has the Company**
18 **demonstrated progress in its reliability quartile ranking over that period?**

19 A11. Figure 1 below presents the Company's SAIDI Ex-MEDs data for the years 2014
20 through 2024. Figure 1 also includes quartile rankings from the Institute of
21 Electrical and Electronics Engineers (IEEE)⁶ reliability benchmark surveys based
22 on standardized reliability metrics across utilities. This data reflects an improving
23 trend in the Company's reliability performance. The results demonstrate that the

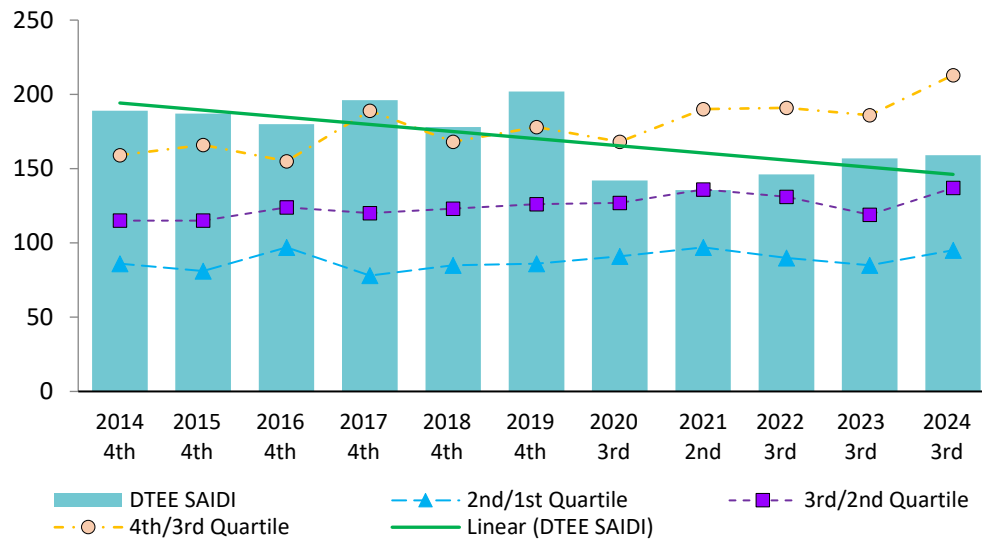
⁵ U-21860 Exhibit A-43 Schedule HH2 - Form EIA-861_Reliability_2021

⁶ 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

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Company's strategic capital investments have yielded measurable reliability improvements. Continued investment in distribution infrastructure remains critical not only to address worsening aging infrastructure and the negative impacts on reliability performance brought about by more frequent extreme weather conditions, but also to improve reliability for customers served by DTE Electric.

Figure 1 – SAIDI Ex-MED Performance (Minutes)⁷



Q12. How does the Company's reliability compare to IEEE benchmarking?

A12. As shown in Figure 1 above, in recent years, the Company's SAIDI Ex-MED has shown improvement and shifted from the fourth quartile to the third quartile (with 2021 reaching second quartile) and closing the gap to the second quartile performance level.

⁷ See U-21860 Exhibit A-23, Schedule M8, page 207 for SAIDI Ex-MED data through year 2022.

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1 Additionally, DTE Electric’s SAIFI performance has consistently ranked in the
2 second quartile for SAIFI Ex-MED, and SAIFI All-Weather has ranked second or
3 third quartile⁸, based on IEEE industry benchmarking.⁹ This broader benchmarking
4 comparison provides a more realistic and balanced view of the Company’s
5 reliability performance than the limited information presented by Witness Alvarez.

6

7 While the U.S. Energy Information Administration (EIA) publishes valuable
8 reliability statistics that Witness Alvarez relies on for his analysis, it does not offer
9 quartile-based industry benchmarking. It is also worth noting the latest industry
10 benchmarks reflect significantly worsening reliability metrics across all three levels
11 of quartiles demarcation for the reliability performance, indicative of the broader
12 extreme weather impacts on aging infrastructure. The relative comparison of the
13 gap between the Company’s performance and the next quartile tier further
14 demonstrates the improving trend of the Company’s reliability performance. Refer
15 to Exhibit A-43 Schedule HH3 - IEEE 2025 Benchmark Results for the latest
16 industry benchmark data.

17

18 **Q13. Are there other witnesses who claim that strategic capital investments do not**
19 **improve reliability?**

20 A13. Yes. Association of Businesses Advocating Tariff Equity (ABTATE) Witness
21 York claims that capital investments have minimal impact on reliability and that,
22 as a result, the Commission should closely scrutinize the Company’s projected

⁸ The Audit Report, Part 1, Chapter VII, Page 89, Observation #3. Also, see Exhibit A-43, Schedule HH4 – SAIFI 2014-2024.

⁹ With one exception in 2023 for All Weather SAIFI due to a severe ice-storm in February and a set of back-to-back severe weather conditions from late June through August

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1 distribution capital expenditures to ensure that the interests of DTE Electric and its
2 ratepayers are reasonably balanced.¹⁰

3

4 **Q14. Does Witness York provide support to make the claim that strategic capital**
5 **investments do not improve reliability?**

6 A14. Witness York does not provide any independent analysis to support this claim.
7 Instead, Witness York references the Company's 2023 Distribution Grid Plan
8 (DGP), U-21860 Exhibit A-23, Schedule M8, pages 40-41 and pages 207-208. The
9 DGP includes reliability data through 2022. As shown in Figure 1 and discussed
10 above (years 2014-2024), this information is included in the DGP on page 207
11 under the title "SAIDI – Excluding MEDs" (years 2014-2022). This demonstrates
12 that even the DGP, which Witness York references as the source for her statements
13 on the Company's reliability performance, reflects progress in reliability.

14

15 **Q15. Does the Company agree with witness York's claim that strategic capital**
16 **investments do not improve reliability?**

17 A15. No. The Company does not agree with this claim.

18

19 **Q16. How has increasing severe weather affected the Company's overall reliability**
20 **performance?**

21 A16. Severe weather has had a significant impact on the Company's reliability, as noted
22 in Part II of my direct testimony. While progress has been made in certain
23 reliability metrics, the broader effects of more frequent and intense storm events
24 continue to challenge system performance. The latest IEEE industry benchmark

¹⁰ Direct testimony of Witness York, page 21, lines 7-12 and page 28, lines 10-13.

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1 data (for calendar year 2024) also reflects the impact of more severe weather
2 conditions that result in worsening reliability performance across the industry. This
3 is a broader industry trend of opposing forces that are counteracting the investment
4 to maintaining and improving reliability. DTE Electric's distribution system,
5 because of its size, advanced age, and complexity, requires sustained higher levels
6 of investment to affect a change in reliability metrics at an overall system level.

7

8 **Q17. In summary, what should the Commission consider when evaluating claims**
9 **that distribution capital investments do not improve reliability?**

10 A17. The Commission should reject the claims presented by AG-MN Witness Alvarez
11 and ABATE Witness York, which are either poorly supported or unsubstantiated,
12 and fail to recognize that, as the Company's analysis demonstrates, capital
13 investment is essential to maintaining and improving reliability and system
14 performance. As discussed above, some of the claims rely on incomplete, incorrect
15 or misleading data. The distribution capital investments are necessary to address
16 aging infrastructure and have already resulted in measurable system improvements.
17 Continued investment will support ongoing progress and deliver better reliability
18 outcomes for customers.

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1 **Rebuttal Issue 2: Recorded Cost in the Early Months of the Year is Not Indicative of**
2 **the Full Year's Results**

3

4 **Q18. Staff Witness Shi made a number of recommended reductions for strategic**
5 **capital projects and programs. Does the Company have any concerns with the**
6 **linear extrapolation methodology applied by Witness Shi?**

7 A18. Witness Shi bases her disallowance recommendation by applying the recorded cost
8 in the early months of the year and estimates the total annual program forecast by
9 applying a linear extrapolation. The reductions she recommends, with which the
10 Company disagrees, are rebutted in detail in Company Witness Rademacher's
11 rebuttal testimony in rebuttal issues 1, 8, and 10-14, and Witness Stowe's rebuttal
12 testimony in rebuttal issue 1.

13

14 While Witness Shi provided sound points in supporting and validating the need for
15 and the benefit of these strategic investments, her recommended reductions are
16 based on an overly simplistic linear extrapolation of the recorded cost in the first
17 four or five months of the year and do not take in to account that the timing of
18 capital expenditures does not occur evenly each month throughout the year.
19 Therefore, amounts spent early in the calendar year should not be the basis for the
20 year-end annual expenditure approval.

21

22 The Company deploys its capital program to provide flexibility and account for
23 potential variability including, but not limited to seasonal variations, unfavorable
24 weather, and various stages of the project execution timing. As part of the
25 operational strategy, the Company prioritized more complex, long duration projects

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1 early in the year. As a result, spending on shorter-cycle programs typically has a
2 lower spent rate in the first half of the year, with those programs expected to ramp
3 up later in the year. This approach reflects a deliberate sequencing of investments
4 to optimize project execution.

5

6 The Company has established the fundamental building blocks to achieve the
7 current 2025 forecast of strategic capital investments across its various reliability
8 improvement programs with the following focus areas:

- 9 • **Engineering & Design:** focus on engineering and design in the early part
10 of the year, with a much lower relative recorded cost.
- 11 • **Material & Equipment:** preparing and stocking of long-lead material and
12 equipment to ensure material availability for the actual field construction
13 and installations.
- 14 • **Construction Resources:** securing construction resources with vendors to
15 prepare for increased ramp up in the latter half of the year.
- 16 • **Permits:** securing the necessary permits so actual field construction work
17 can proceed unimpeded.
- 18 • **Site Inspection and Readiness:** completed field inspections and site
19 readiness to execute field work.
- 20 • **System Shutdown Coordination:** planning for load serving contingencies
21 during construction to reduce complexity and the need for additional
22 operational protocols, thus minimizing required system shutdowns and
23 internal coordination between groups in place to ensure each respective area
24 can execute as needed.

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1 The programs slated for higher expenditure rate in the latter half of the year are
2 Pole-Top Maintenance and Modernization Program (PTMM), 4.8kV Hardening,
3 and Distribution Automation. All of these programs can achieve fast ramp ups due
4 to the type/scope of work performed. The Company's investment patterns in recent
5 years followed this same upward trend in the second half of the year, including
6 2022 and 2023.

7

8 **Q19. What is the Company's recommendation regarding Witness Shi's proposed**
9 **reductions?**

10 A19. Company Witnesses Rademacher and Stowe address specific reductions proposed
11 by Witness Shi based on year-to-date spend or run rate. As the Company has
12 demonstrated in the preceding Q&As and in the respective Company Witnesses'
13 testimonies, these capital investments are not only necessary as supported by
14 rigorous benefit and cost analysis, but they also provide meaningful reliability
15 benefits that DTE Electric customers deserve. Witness Shi's recommended
16 reductions should be rejected because they rely on a linear extrapolation of early
17 year-to-date recorded costs, which is not an appropriate basis for projecting full-
18 year expenses.

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1 **Rebuttal Issue 3: Proposals to Prioritize O&M Over Capital Will Lead to Increase**
2 **Asset Failures and Reactive Cost**
3

4 **Q20. What claims do AG-MN Witnesses Alvarez and Stephens make related to the**
5 **capitalization of routine maintenance activities, specifically Tree Trim and**
6 **PTMM programs?**

7 A20. AG-MN Witness Alvarez, on page 15 lines 10-11, criticizes the capitalization of
8 activities that he believes should be accounted for as routine O&M spending.
9 Similarly, AG-MN Witness Stephens posits on page 50-51 “that routine program
10 activities that comprise a substantial part of PTMM program costs, including pole
11 testing, poletop inspections, and the vegetation management often required to
12 complete these, are required by the USOA to be expensed as routine operations and
13 maintenance (‘O&M’) costs. DTE is capitalizing some or all of these costs as part
14 of the PTMM program.”
15

16 **Q21. How does the Company respond to these claims?**

17 A21. The Company disagrees. The Company follows the Uniform System of Accounts
18 (USOA) guidelines. In addition, the Company follows a capitalization policy that
19 guides how expenditures are categorized and informs the appropriate accounting
20 treatment. For additional details on the Company’s accounting practices and how
21 they align with USOA standards, please refer to Company Witness Uzenski’s
22 rebuttal testimony in sections PTMM program capitalization and capitalization
23 policies.

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1 **Q22. On what basis does AG-MN Witness Alvarez claim that the Company should**
2 **prioritize increased O&M spending over capital investments?**

3 A22. Witness Alvarez cites three conclusions in the Audit Report that he claims support
4 his view that the Company should prioritize increased O&M spending over capital
5 investments to improve reliability.

6 • “ . . . accelerated forestry cycles . . . (form) a core element of measures that
7 will move reliability cost effectively toward achievement of (DTE)
8 reliability targets.”

9 • “DTE’s much longer cycle for pole and poletop equipment inspection and
10 replacement exposes the system to continuing and significant reliability
11 risk.”

12 • “DTE does not use Event Classification as a catalyst for organizational
13 mobilization leading up to a weather event.”¹¹

14

15 **Q23. Does the Company believe that the conclusions in the Audit Report cited by**
16 **Witness Alvarez are recommending increased O&M spending instead of**
17 **capital investments is the preferred approach to improving reliability?**

18 A23. No. The Company does not agree with Witness Alvarez’s perspective. The Audit
19 Report identifies a need for improvement to the Company’s distribution equipment
20 to reduce SAIDI minutes. See, for example, the excerpt below for one of the
21 observations from the Liberty Audit Report¹²:

22

23 *“6. DTE’s distribution lines contribute approximately 88 percent of SAIDI*
24 *minutes. Equipment caused outages were the greatest contributor to SAIDI on*

¹¹ Direct Testimony of Witness Alvarez Page 9, lines 14-20, page 10, lines 1-9

¹² Case No. U-21305 Dkt. Nos. 12, 13 (the “Audit Report”), Liberty Audit Report – Part 1, Page 90

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1 *Blue Sky days including storms causing less than 15,000 customer outages.*
2 *This indicates the condition of DTE's distribution equipment requires*
3 *improvement to reduce SAIDI minutes."*

4

5 Importantly, this observation does not suggest prioritizing O&M spending over
6 capital investments as the means to address the condition of the distribution
7 equipment in order to improve reliability. Rather, the audit report recommended
8 the need to integrate increased O&M with the significant amount of capital
9 investment, but does not suggest displacing capital investment with increased
10 O&M. Witness Alvarez's characterization of the report appears to instead reflect
11 his own preference that extends beyond the report's actual findings.

12

13 **Q24. Does Witness Alvarez make any additional related claims?**

14 A24. Yes, on page 15 lines 11-15, he recommends that "some types of O&M activities
15 increase." He goes on to state that "these recommendations, if followed, will
16 increase rates in the short term. To compensate, capital spending reductions are an
17 available option, but such cuts must be severe if they are to offset O&M spending
18 increases and the associated rate increases. Other strategies designed to relieve the
19 rate pressure of increasing O&M activity, such as securitization of catch-up
20 activity, also warrant Commission consideration."

21

22 **Q25. How does the Company respond to this recommendation?**

23 A25. The Company does not agree with Witness Alvarez's recommendation. First, it is
24 unclear exactly to what "some type of O&M activities" he is referring. Second,
25 while O&M activities, such as inspections and repairs are essential for maintaining

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1 system reliability and safety, these activities alone are insufficient to achieve
2 sustained reliability improvements.

3

4 For example, inspections conducted under the PTMM program may identify
5 overhead assets that require replacement to improve system reliability and safety.

6 In such cases, additional capital investment is required to replace or upgrade those
7 assets. Without the corresponding capital work, the reliability benefits initiated by
8 the O&M inspections cannot be realized. In other words, inspections are diagnostic
9 in nature; they identify issues, but do not resolve them. Capital investment is
10 necessary to implement the solutions that drive long-term reliability improvements.

11

12 Lastly, the Company's outage response is inherently reactive, addressing outages
13 only after they have occurred. While enhancements to the Company's outage
14 response can reduce the duration of outages, they do not contribute to preventing
15 outages from occurring. If capital investments are reduced, as proposed by Witness
16 Alvarez, the grid's condition is likely to deteriorate further, leading to an increase
17 in outage frequency and a decline in overall reliability. The proposed approach of
18 O&M expenditure in lieu of capital investments is a very risky proposition, as the
19 system will reach a point in the near future where anticipated increases in asset
20 failure will result in customers' paying for emergency repair and replacement that
21 comes at a much higher cost, not to mention the potential for the volume of these
22 emergency repairs and replacements to overwhelm the available resources needed
23 to address the problems reactively.

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1 **Q26. Witness Alvarez claims that the Company is not only failing to catch up but is**
2 **falling further behind in its Vegetation Management efforts. How does the**
3 **Company respond to this assertion?**¹³

4 A26. The Company disagrees. The Company brought its tree trimming program to 92%
5 on-cycle at the end of 2024 with the goal to be 100% on-cycle by the end of 2025
6 as detailed in Company Witness Steudle’s direct testimony.

7

8 Witness Alvarez references Figure 3 on page 11 of his direct testimony, which is
9 the same figure cited by Witness Stephens as Figure 4 on page 19 of his direct
10 testimony. The data presented in this figure is inaccurate. Company Witness
11 Steudle addresses these inaccuracies in Part 2 of her rebuttal testimony.

12

13 In the current case, the Company’s requested funding for 2026 is consistent with
14 spending levels made during the Surge period and represents an increase of more
15 than 170% compared to pre-Surge levels (2014–2018). This funding reflects the
16 Company’s ongoing commitment to Vegetation Management. For additional
17 details, please refer to Witness Steudle’s rebuttal testimony, specifically Figure 1
18 on page 22.

19

20 **Q27. Witness Alvarez asserts on pages 20-21, lines 4-6, that the Company is**
21 **“masking” the true cost of service and keeping the rates artificially low in the**
22 **short term through inappropriate capitalization practices and deferring**
23 **essential O&M activities. Do you agree with this assertion?**

¹³ Direct Testimony of Witness Alvarez, pages 10-11, lines 12-3

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1 A27. No. The Company disagrees with Witness Alvarez's assertion that it is "masking"
2 the true cost of service through inappropriate capitalization practices and deferral
3 of essential O&M activities. As referenced earlier in my testimony, Company
4 Witness Uzenski addresses these misleading claims in her rebuttal testimony.
5 Separately, as discussed above, the Company's commitment and funding request
6 for the tree trimming program demonstrates a continued commitment to reliability
7 and proactive system maintenance.

8

9 **Rebuttal Issue 4: Benefit-Cost Analyses Support Capital Optimization, Not**

10 **Spending Bias**

11

12 **Q28. Can you summarize the AG-MN witnesses' views on Company's engagement**
13 **with 1898 & Co. for its Benefit-Cost Analyses (BCA) in this case?**

14 A28. Yes. AG-MN Witness Alvarez stated on page 35, lines 18-20 "...we have found
15 the models Mr. DeStigter developed to be biased in favor of capital spending, and
16 not oriented to improvements in capital spending decision-making or capital
17 spending optimization." AG-MN Witness Stephens, on page 50, lines 5-7 indicates
18 that he shares Witness Alvarez's concerns and "DTE develops its models to justify
19 increases in capital spending rather than to inform the best business decisions for
20 customers."

21 **Q29. How do you respond to the claims made by AG-MN Witnesses Alvarez and**
22 **Stephens?**

23 A29. I disagree with the characterization that the models the Company used are biased
24 in favor of capital spending, and not oriented to improvements in capital spending

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1 decision-making or capital spending optimization. In addition to the Global
2 Prioritization Model (GPM) and the Reliability Model previously developed to
3 prioritize our investments proposals, both supported by Company Witness
4 Kryscynski in his direct and rebuttal testimony, the Company is presenting an even
5 more comprehensive benefit-cost analysis with respect to certain programs and
6 projects in this case. Providing BCAs for PTMM, Distribution Automation,
7 Strategic Undergrounding Pilot, and Grid Automation Telecommunication reflects
8 the Company's responsiveness to prior recommendations from Witnesses Alvarez
9 and Stephens and is appropriately responsive to feedback received from the
10 Commission.¹⁴

11

12 **Q30. Witness Alvarez asserts that because DTE Electric awarded \$138.9 million in**
13 **outsourced engineering work to firms like Burns & McDonnell in 2024, the**
14 **1898 & Co. Benefit-Cost Analysis (BCA) is biased. Does the Company agree**
15 **with this assessment?**¹⁵

16 A30. No. The Company does not agree. Witness Alvarez misinterpreted the Company's
17 discovery response. As shown in U-21860 Exhibit A-43, Schedule HH5
18 (Discovery Response MNSCDE-3.32h), the referenced \$138.9 million was
19 distributed across sixty different engineering firms that provided services to DTE
20 Electric. The Company broadly allocates its engineering work, contrary to Witness
21 Alvarez's assertions. Simply because Burns & McDonnell has done work for the
22 Company does not create bias in the 1898 & Co BCA.

¹⁴ Case No. U-21534 Order dated January 23, 2025, pages 108, 142, 148, and 154

¹⁵ Direct Testimony of Witness Alvarez, page 35, lines 11-13

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1 **Q31. How does the Company respond to Witness Alvarez’s claim that DTE’s**
2 **modeling approach has not been made transparent to intervenors or that**
3 **intervenors have been unable to evaluate DTE’s work as a result of its**
4 **“opacity”?**¹⁶

5 A31. The Company disagrees. The Company has gone to significant measures and
6 expended significant resources to ensure the transparency of its modeling approach
7 throughout this proceeding.

8 First, the Company hosted two technical conferences, lasting more than 10 hours
9 in combined duration, during which subject matter experts explained the model and
10 answered questions. Witness Alvarez attended both sessions and asked questions.
11 Second, the Company provided substantial information requested in discovery and
12 model outputs in full¹⁷. Lastly, these models require advanced tools beyond Excel.
13 It is therefore contradictory for Witness Alvarez to support advanced modeling
14 while simultaneously criticizing the tools necessary to implement it.

15

16 In summary, the Company has expended significant resources to ensure that the
17 data and analyses underlying its requests in the instant proceeding are available to
18 and explained to intervenors and the Commission. Witness Alvarez’s testimony to
19 the contrary lacks credibility and should be disregarded.

20

21 **Q32. Do other witnesses discuss the Company’s transparency with its BCA**
22 **modeling approach?**

23 A32. Yes, CEO Witness Volkman, in contrast to AG-MN Witness Alvarez, notes:

¹⁶ Direct Testimony of Witness Alvarez, page 36, lines 14-16

¹⁷ The Company provided responses to over 150 discovery questions pertaining to the BCAs.

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1 The Company and its BCA consultant 1898 & Co. have been very
2 transparent and responsive. The CEO had a 1-hour Teams call with 1898
3 & Co. on June 4, 2025, to discuss some initial BCA questions. 1898 & Co.
4 subsequently hosted two technical conferences (7.5 hours on June 11, 2025,
5 3 hours on June 26, 2025) to explain the BCA methodologies and to answer
6 questions from the CEO and other stakeholders. 1898 & Co. also joined the
7 CEO's July 18, 2025, Teams call with DTE to further explain the BCA
8 analysis. For the most part, I found 1898 & Co.'s responses to the numerous
9 questions and data requests to be thoughtful, thorough, and credible.¹⁸

10

11 This further illustrates that the Company's engagement with 1898 & Co. was
12 conducted through a robust, transparent, and collaborative process, providing
13 stakeholders with multiple opportunities to understand and evaluate the BCA
14 methodology.

15

16 **Q33. How does the Company respond to Witness Alvarez's criticism that the 1898**
17 **& Co. BCA was developed to justify capital spending decisions already made**
18 **rather than improving decision making around capital spending?**¹⁹

19 A33. Witness Alvarez mischaracterizes the 1898 & Co. model. The model presents a
20 comprehensive framework that enables DTE Electric to make prudent, customer-
21 focused investment decisions. Improved regulatory outcomes result from the
22 Company's ability to evaluate each investment through a robust benefit-cost
23 analysis that links customer benefits to project costs. Witness DeStigter's rebuttal
24 testimony provides more specific responses to Witness Alvarez's critiques.

¹⁸ Direct Testimony of Witness Volkman Page 4 Line 17 thru Page 5 Line 5

¹⁹ Direct Testimony of Witness Alvarez Page 35, Lines 5-10

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1 **Q34. Witness Alvarez recommends that the Company perform a risk-informed**
2 **benefit-cost analysis for System Loading projects. Does the Company agree?**²⁰

3 A34. No. The value of system loading projects is driven by addressing capacity
4 constraints as a fundamental obligation to serve the customer loads. These projects
5 address risks such as equipment failure from overloading—e.g., transformers
6 operating beyond safe limits—which can lead to safety hazards and service
7 disruptions. Capacity investments are therefore necessary and proactive. Applying
8 a rigid benefit-cost ratio to these decisions is not appropriate, as it overlooks the
9 operational realities and regulatory obligations of grid management. Calls for
10 BCAs in this context often reflect a misunderstanding, or lack of appreciation for,
11 these core electric utility responsibilities.

12

13 For additional details regarding the Company's System Loading concerns, please
14 see Rebuttal Topic 2 of Company Witness Stowe's rebuttal testimony.

15

16 **Q35. Witness Alvarez recommends that the Commission order DTE to complete**
17 **risk-informed benefit-cost analyses for all strategic capital projects designed**
18 **to improve safety or reliability in future rate cases**²¹. **He further states that**
19 **such analyses should be required for any discretionary capital project or**
20 **program exceeding one million dollars. Does the Company agree?**²²

21 A35. No. The Company does not agree with this recommendation. While BCAs can be
22 valuable in certain contexts, they are time- and resource-intensive and are not
23 suitable for all strategic capital investments. DTE Electric believes requiring risk-

²⁰ Direct Testimony of Witness Alvarez, Page 27, Lines 10-12

²¹ Direct Testimony of Witness Alvarez U-21860, Page 6, Line 1

²² Direct Testimony of Witness Alvarez U-21860, Page 27, Lines 12-14

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1 informed BCAs for all projects over one million dollars or those aimed at improving
2 safety or reliability would be inefficient and may hinder timely execution.

3

4 This topic was already addressed in Case No. U-21534 in Company Witness
5 Kryscynski's rebuttal testimony (Q/A 38, pages AJK-22 thru AJK-23), and
6 subsequently ruled on by the Commission in the Commission's own determination
7 in Case No. U-21534. On page 97 of the Order, the Commission stated:

8 *'The Commission also agrees with DTE Electric that requiring a full BCA*
9 *for every investment category is not practical or advisable.'*

10

11 This reinforces the reality that a blanket requirement for BCAs across all strategic
12 capital projects or cost levels is neither practical nor consistent with sound planning
13 principles. Importantly, the Company has already completed four BCAs in this
14 case (which supplement the GPM and Reliability Model), demonstrating its
15 commitment to thoughtful evaluation. As listed above, the four BCAs address: 1)
16 PTMM, 2) Strategic Undergrounding Pilot, 3) DA, and Grid Automation
17 Telecommunications.

18

19 **Q36. What does AG-MN Witness Alvarez recommend related to the results of the**
20 **PTMM BCA model?**

21 A36. Witness Alvarez on page 44, lines 12-15 recommends the Commission to "Treat
22 the PTMM BCA model's results as nonrelevant. Instead, order DTE to complete
23 risk-informed benefit-cost analyses on a) the change in poletop visual inspection
24 cycle from ten years to five years; and b) the changes in poletop construction

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1 standards.” He further asserts that the PTMM BCA model developed by 1898 &
2 Co. does not address the incremental benefits and costs of these changes.²³

3

4 **Q37. Does the Company agree with this recommendation?**

5 A37. No. The PTMM BCA is a rigorous, data-driven analysis that provides meaningful
6 insights into pole and poletop maintenance investments. Disregarding its relevance
7 undermines its strategic value and contradicts sound regulatory and economic
8 principles. Requiring the Company to conduct an undefined yet different risk-
9 informed BCA on the transition from a ten-year to a five-year pole-top visual
10 inspection cycle is unwarranted. For additional details on the Company’s PTMM
11 program, refer to Company Witness Robinson’s revised direct testimony as well as
12 Witness Robinson’s Rebuttal, Issue #3. The inspection cycle change was
13 implemented in direct response to the Audit Report recommendation and is
14 supported by Commission guidance.

15

16 Additionally, requiring a separate risk-informed benefit-cost analysis for changes
17 in construction standards is unnecessary. The Company, along with 26 other
18 utilities, participated in a three-year research initiative with the Electric Power
19 Research Institute (EPRI), culminating in the *Distribution Grid Resiliency* report.²⁴
20 This study found that fiberglass crossarms outperform wooden crossarms in both
21 static load and deflection, and that polymer insulators are more resilient than
22 porcelain alternatives. This topic was addressed in discovery response MNSCDE-
23 1.8b as provided in Exhibit A-43 Schedule HH6. Importantly, the current PTMM
24 BCA already incorporates the costs associated with deploying these updated

²³ Direct Testimony of Witness Alvarez, Page 43-44, Lines 22-5

²⁴ <https://eprijournal.com/making-distribution-grids-stronger-more-resilient/>

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1 standards, thereby demonstrating the positive value of the construction standard
2 changes within the existing analytical framework.

3 **Q38. Do any other witnesses have recommendations regarding the Company's**
4 **Benefit Cost Analysis?**

5 A38. Yes. DAAO Witness Kinkhabwala recommends "distributed solutions and non-
6 wires alternatives such as solar+storage" be included in the Company's BCA and
7 planning.²⁵

8
9 **Q39. What is the Company's approach to BCA?**

10 A39. The Company continues to enhance its BCA framework to support well-informed,
11 customer-focused investment decisions. As the Company continues this journey,
12 the Company may consider BCAs for non-wire alternatives in the future.

13
14 **Rebuttal Issue 5: Distribution System Plan Serves to Provide Strategic Roadmap for**
15 **the Grid and Not Suitable for Contested Case. Eliminating Constant Dollar**
16 **Averaging Is Not a Relevant Trade-off for a Contested DSP**

17
18 **Q40. Do you agree with MNC Witness Jester's recommendation on page 23 to not**
19 **accept constant dollar averaging (CDA) for Distribution Operations Capital**
20 **Spending unless the Commission establishes a contested case for Distributed**
21 **Grid Planning (DGP) and implements performance-based ratemaking (PBR)**
22 **for Distribution Capital programs?**

23 A40. No. Witness Jester's attempt to link the CDA to the DGP and PBR lacks a clear
24 basis and is unsupported by evidence. Moreover, Witness Jester's proposal to tie

²⁵ Direct Testimony of Witness Kinkhabwala, page 56, Lines 1-3

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1 CDA to unrelated matters (PBR and the nature of the DGP) undermines the very
2 premise of objecting to CDA. Company Witnesses Lyons and Hill address why
3 CDA is an appropriate methodology for forecasting Base Capital programs.
4 Therefore, the recommendation to disallow CDA as an alternative to a contested
5 case DGP and implementing PBR is unjustified, and the Commission should reject
6 it.

7
8 **Q41. Do you agree with his recommendation that the Commission establish a**
9 **contested case process for Distributed Grid Planning?**

10 A41. No. The Company does not support treating the Distribution Grid Plan as an
11 additional contested case proceeding, as this would introduce unnecessary
12 complexity, slow progress, and ultimately disadvantage customers. DTE Electric
13 believes this approach would duplicate existing regulatory processes without
14 offering meaningful benefits, particularly given that general rate cases already
15 provide opportunities for discovery and for stakeholders to challenge proposed
16 investments. The current planning framework, combined with contested rate cases,
17 strikes a reasonable balance between collaboration and stakeholder input.

18
19 **Q42. What did the Commission decide in Case No. U-20147 regarding the treatment**
20 **of the distribution plan as a contested case?**

21 A42. On page 134 of the Case No. U- 20147 Commission Order dated September 26,
22 2024, the Commission highlighted a key element of the Staff's straw proposal:

23
24 "For this distribution plan docket to remain as an uncontested case at this
25 time to serve as an informational docket containing forward outlooks that

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1 will feed into the utilities' general rate case filings. All supporting data,
2 exhibits, and testimony will continue to be required in any rate case filings
3 that cite this informational docket, which is designed to present strategic
4 vision and planning goals for each utility;"

5
6 This recent determination confirms that the preferred approach is maintaining the
7 distribution plan docket as an informational, non-contested case rather than
8 converting it into a contested case proceeding and Witness Jester's
9 recommendation should be rejected.

10

11 **Q43. Do you agree with MNC Witness Jester's recommendation to implement a**
12 **performance-based rate making approach for DTE Electric's Distribution**
13 **Capital, including its Base Capital programs?**

14 A43. No. The Commission established the Financial Incentives and Disincentives
15 workgroup as part of the MI PowerGrid Initiative in Case No. U-21400, a docket
16 which includes more than two years of comments, proposal updates, and
17 engagement. The Company filed its Performance Based Ratemaking Mechanism
18 as directed in the Commission's Order in Case No. U-21400, on April 15, 2025, in
19 Case No. U-21909, a contested case. Based on this, it would be inappropriate to
20 pursue additional or standalone PBR and, as such, the Commission should reject
21 this recommendation.

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1 **Rebuttal Issue 6: The Audit Scope was Comprehensive with Constructive Findings**

2

3 **Q44. Witness Alvarez suggests that the Audit Report was missing two additional**
4 **scopes of work -- a forensic audit and an accounting audit²⁶. Does the**
5 **Company agree?**

6 A44. No. While Witness Alvarez does not formally recommend that the Commission
7 initiate additional audits, he implies that the Liberty Audit was incomplete.
8 However, the Liberty Audit was independently conducted and appropriately scoped
9 to evaluate DTE Electric's operational and financial practices as they relate to
10 reliability and customer service. The findings from Liberty Audit provided a broad
11 base of constructive feedback that helped to inform actionable improvement in the
12 Company's investment plan. Witness Alvarez's proposal is both unnecessary and
13 out of scope for this case and should be rejected by the Commission.

14 **Rebuttal Issue 7: Need for Sustained Capital Investments Misconstrued as a Short-**

15 **Term Surge of Capital & O&M Catch-Up**

16

17 **Q45. Witnesses CUB-NRDC Bunch²⁷; MNC Jester²⁸; CEO Kenworthy²⁹; and CEO**
18 **Tan³⁰ have testified that the increase in capital and O&M expenditure**
19 **requested in this case is a temporary phenomenon and proposed that the**
20 **Commission direct the Company to finance its investments through**
21 **securitization, similar to the surge scenario. How does the Company respond?**

²⁶ Direct Testimony of Witness Alvarez, page 18, lines 7-15

²⁷ Direct Testimony of Witness Bunch, page 37-38, lines 16-16

²⁸ Direct Testimony of Witness Jester, pages 34-35, lines 12-4

²⁹ Direct Testimony of Witness Kenworthy, pages 24-26, lines 15-15, and page 33, lines 14-17

³⁰ Direct Testimony of Witness Tan, pages 4-19

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1 A45. The Company disagrees with this proposal, in part, as it is built on the erroneous
2 assumption that the proposed increase in capital and O&M expenditures is
3 temporary in duration and is intended to “catch up” on prior lack of expenditure.
4 At the very core of this concept of a surge securitization proposal is the incorrect
5 assumption of the existence of a baseline level of steady capital and O&M
6 expenditures for perpetuity. The proposal overlooks the dynamic and evolving
7 nature of the grid, as well as the increasing demands placed on aging infrastructure
8 to maintain and improve reliability.
9
10 In my direct testimony, I elaborated on the three key external factors that are
11 impacting the performance of the grid and the resulting need for sustained
12 investments in the grid.³¹ In this case, these external forces form an emerging trend
13 that is driving the need for an increase in capital and O&M expenditures for the
14 foreseeable future. This is also corroborated by one of the findings in the Audit
15 Report.³² These are universal issues facing the power grid infrastructure across the
16 country. In the case of DTE Electric’s power grid, these challenges are further
17 exacerbated by the more advanced aging of the grid infrastructure, changing
18 weather conditions evidenced by increasing frequency and intensity of storms and
19 the “lake-effect” that is unique to Michigan³³, the combination of which mean that
20 the assets in the power grid are reaching the edge of the bathtub failure curve and
21 starting to experience a rapid increase in failure rate for equipment that has far
22 surpassed its full useful life. Commission support of the investments proposed in

³¹ Direct Testimony of Witness Chiu, pages BC-10, BC-14 thru BC-21

³² See The Audit Report, Part 1 – Chapter I (Page 4) with discussion on reliability improvements achieved by industry peer “is a result of very substantial investments over the last 20 or more years.”

³³ The Audit Report, Part 1, Chapter VI, Page 54

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1 this case and of the aggregate rate relief needed for the Company to execute them³⁴
2 will avoid the further deterioration of the system. Company Witness Stowe
3 provides examples of the dire consequences of inaction and lack of funding in his
4 rebuttal testimony.

5
6 **Q46. Witness Tan conducts several comparative evaluations involving DTE Electric**
7 **and nine other peer utilities. These evaluations include assessments of**
8 **Distribution Capital Additions per Customer, Electric Distribution O&M**
9 **Expense per Customer, Distribution Plant in Service per Customer, and**
10 **reliability indices such as SAIDI, SAIFI, and CAIDI. How does the Company**
11 **address the observations presented in these evaluations?**³⁵

12 A46. The Company appreciates Witness Tan's effort in preparing the comparative
13 evaluations but notes that the selected peer group may not reflect DTE Electric's
14 unique operational, geographic, and structural characteristics. This limits the
15 relevance of the comparisons and the performance measures used may not be
16 appropriate for this context. Moreover, it is unclear whether the selected measures
17 are appropriate indicators for assessing utility performance in this context, and the
18 analyses do not appear to support any definitive conclusions regarding DTE
19 Electric's relative performance.

20

21 Even Witness Tan acknowledges variability among peer utilities, particularly in
22 weather patterns and operating conditions. As stated in Witness Tan's testimony
23 (page 17, lines 7-12):

³⁴ Refer to the Direct Testimony of Company Witness Bruzzano

³⁵ Direct Testimony of Witness Tan, pages 4-19

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1 “Finally, I want to recognize that the peer utilities used for my distribution
2 and reliability analyses are located throughout the Midwest and the Rust
3 Belt. Based on their location and topology, each utility experiences weather
4 differently; some operate in high elevation and/or forested areas, while
5 others might experience more snow and sleet than others. Large storms
6 might roll into a service territory like DTE’s and dissipate by the time the
7 clouds reach Duquesne Electric.”

8 Given these limitations, including the lack of alignment between the peer group and
9 DTE Electric’s unique characteristics, the questionable relevance of the selected
10 performance measures, and the variability in operational conditions across utilities,
11 the Company recommends that the Commission assign minimal weight to this
12 analysis when evaluating DTE Electric’s performance.

13 **Q47. Witness Tan infers that the Company is spending above the peer average in**
14 **an effort to catch up on system reliability. How does the Company respond?**³⁶

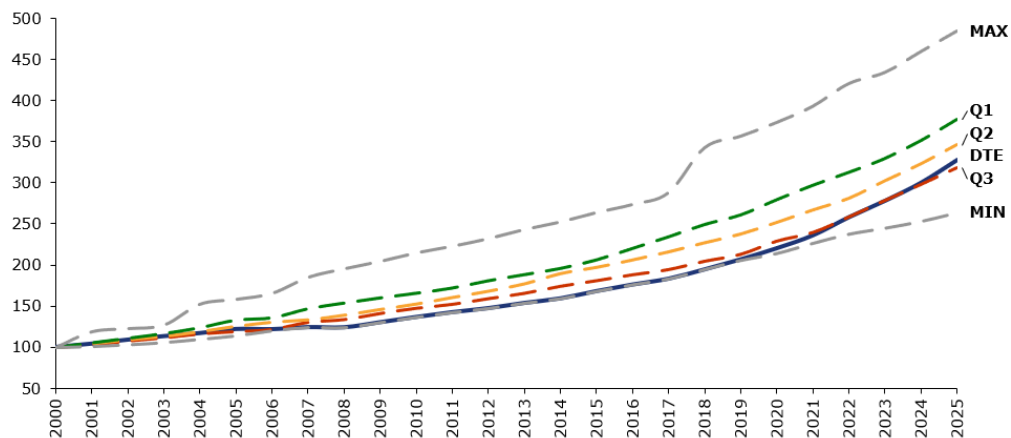
15 A47. The Company believes that Witness Tan’s analysis of Capital Investment Per
16 Customer is not the appropriate way to view the current situation. To provide a
17 more meaningful comparison, the Company analyzed net capital additions over 25
18 years for a broader peer group of 23 utilities, including DTE Electric as shown in
19 Figure 2 below. To accomplish this, the Company Indexed all Company’s
20 beginning of the year “Total Distribution Plant” from FERC Form 1 to the number
21 100 – thus all utilities start the analysis assuming a similar condition rate base.
22 Using this indexing method allows for a more effective comparison of capital
23 investment trends than annual per-customer spending alone.

³⁶ Direct Testimony of Witness Tan; page 8, lines 1-10; page 9, lines 5-11; page 16. Lines 4-7

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1 What this analysis shows is that while DTE Electric is increasing capital
2 investment, it still is well below average and shows, when taken in conjunction with
3 all the evidence presented by the Company in this case, that increased and sustained
4 investment is required to improve the system – this is not a short-term surge.

5 **Figure 2 DTE vs. Peer Set – Net Distribution Capital Additions since**
6 **2000 (2000 Net Distribution Plant = 100)³⁷**



7

8 **Q48. Do you have any concerns with this analysis?**

9 A48. Yes. While the analysis offers a helpful directional view of DTE Electric’s need
10 for sustained capital investment, it likely understates the true scale of that need.
11 Drawing on my extensive industry experience—including leadership roles within
12 the IEEE Power & Energy Society and EPRI’s Energy Delivery & Customer
13 Solutions Advisory & Sector Council—I believe the analysis presents an overly

³⁷ Peer set based on DTE cost benchmarking group: Ameren MO, BGE, Cleveland EIC, ComEd, Connecticut P&L, CMS, Dayton P&L, Delmarva, Duke OH, Duquesne, LGE, Massachusetts EC, Narragansett, Niagara Mohawk, NIPSCO, Northern States MN, NSTAR, PECO, Potomac, PSEG, Rochester G&E, WI P&L

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1 optimistic picture of the significant investment required to align DTE Electric's
2 grid with industry peers
3

4 **Q49. Can you summarize your recommendation regarding the proposals for surge**
5 **securitization to fund the increase in capital and O&M expenditures?**

6 A49. The Company does not agree with the proposed surge securitization
7 recommendations. The proposed path of securitization treatment (with a lower
8 authorized rate of return) for the increase in capital and O&M expenditure is based
9 on the flawed assumption that there is a steady, lower baseline of capital and O&M
10 expenditures and is not supported by the facts presented in this case. This
11 securitization approach proposed by Witnesses Bunch (CUB-NRDC), Jester
12 (MNC), and Kenworthy and Tan (CEO) conflicts with the long-established
13 principles of how utility investments should be financed. As discussed in detail in
14 the rebuttal testimony of Company Witness Lepczyk, securitization of distribution
15 investments is not appropriate and could lead to negative customer consequences
16 by impacting the Company's ability to finance the investments that are necessary
17 to ensure the safety and reliability of the grid.
18

19 **Q50. Does MNC Witness Jester make any other recommendations related to the**
20 **surge securitization proposal?**

21 A50. Yes. On page 34 Witness Jester recommends "the Commission order DTEE to
22 propose in its next rate case the baseline spending and surge spending in each
23 distribution system program as well as the duration or criteria for ending surge
24 spending and considering subsequent spending to be normal utility activity."

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1 **Q51. Does the Company agree with this recommendation?**

2 A51. No. As discussed in Q45, at the heart of the “surge” proposal lies a flawed
3 assumption: that there exists a perpetual, baseline level of steady capital and O&M
4 expenditures. This premise fails to account for the dynamic nature of the electric
5 grid and the evolving demands placed on aging infrastructure. It overlooks the
6 reality that maintaining and enhancing reliability requires flexible, responsive
7 investment strategies that adapt to changing conditions and emerging challenges.
8 Therefore, this recommendation should not be adopted.

9
10 **Rebuttal Issue 8: Community Coordination Practices**

11
12 **Q52. On pages 21–22, lines 16–6 of MAUI Witness Schultz’s direct testimony, he**
13 **argues that the Company is not in compliance with Commission orders,**
14 **focusing on the term “forthcoming” and the timing of municipal notification.**
15 **Does this accurately describe the Company’s approach?**

16 A52. No. The Company complies with the U-21534 Commission Order³⁸ by notifying
17 municipalities of upcoming projects through established engagement practices.
18 The term “forthcoming” appropriately reflects the Company’s ongoing efforts to
19 inform municipalities and other utilities about upcoming projects through a robust
20 set of engagement mechanisms.

21
22 Each community within the Company’s service area is supported by a dedicated
23 Regional Affairs manager who serves as the primary liaison between the Company
24 and the community. These managers are well known to municipal leaders and are

³⁸ Case No. U-21534 Order dated on January 23, 2025, pages 458-459

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1 typically the first point of contact for a wide range of topics, including project
2 coordination.

3

4 **Q53. Witness Schultz also claims that the Company has not demonstrated proactive**
5 **review of publicly available infrastructure plans from municipalities and other**
6 **utilities. Do you agree?**

7 A53. No, I do not agree. While the Company does not conduct a systematic review of
8 every publicly available infrastructure plan, it engages in proactive coordination
9 through direct and ongoing engagement with municipalities and other utilities. The
10 Company's coordination practices are built around regular, structured engagement
11 with municipal and utility stakeholders. Through our Regional Affairs managers
12 and project teams, we routinely meet with local officials to discuss infrastructure
13 needs, timelines, and potential overlaps. These meetings provide a forum for
14 reviewing and aligning plans, identifying conflicts, and coordinating schedules.
15 While Witness Schultz suggests that the burden is placed on municipalities to raise
16 concerns, the process is designed to facilitate two-way communication.

17

18 DTE Electric has regular Infrastructure Coordination Meetings with several cities
19 and counties. An example of a project that came about regarding shared planning
20 is the Spruce undergrounding pilot project. Refer to Company Witness Stowe's
21 revised direct testimony, pages 128 to 129 Lines 19-3, and pages 130 to 131 Lines
22 21-3 for additional information on the Spruce undergrounding pilot project.

23

24 **Q54. Witness Schultz states that the Power Improvements Map (PIM) does not**
25 **support meaningful coordination. How does the Company respond?**

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1 A54. Primary coordination with communities occurs through Infrastructure Coordination
2 meetings. While the PIM serves as a useful tool for viewing the Company's work
3 in an accessible and transparent format, it is not the primary means of coordination.
4
5 Additionally, as stated in my direct testimony on pages BC-41 Line 14 -to BC-42,
6 Line 6, the Company has taken proactive steps to begin using the State's
7 coordination tool, the Michigan Infrastructure Council (MIC), to support
8 infrastructure collaboration. The MIC is actively engaging with entities across
9 Michigan, and its MiDIG Project Portal is designed to assist asset owners, utilities,
10 and agencies with cross-asset coordination. DTE Electric expects to begin testing
11 project data uploads to the portal later in 2025.

12

13 **Q55. Witness Schultz states the MIC portal includes only *current* electric projects,**
14 **while gas projects are *planned*, and that the *current* electric data is no more**
15 **useful than the PIM. How does the Company respond?**

16 A55. The Company believes that participation in the MIC portal will address any
17 reasonable interpretation of coordination and Witness Schultz's assessment may be
18 a misunderstanding of the function of the MiDIG Portal. As described at
19 www.michigan.gov/mic/project-portal, "The MiDIG Project Portal is a GIS based
20 platform that allows users to share capital improvement plans statewide and
21 streamline communication, enhance transparency, and facilitate seamless
22 collaboration among all stakeholders involved in infrastructure projects." Both
23 current and planned electric and gas projects will be included in the MIC portal
24 over time. The MIC provides contact information for these projects, and when
25 multiple parties add overlapping activities at the same location, the system is

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1 designed to auto-generate conflict notification emails to all parties, enabling
2 resolution tracking within the MIC platform.

3

4 **Q56. Can you cite some actual examples of coordination activities that the Company**
5 **has undertaken to demonstrate the effectiveness of these infrastructure**
6 **coordination efforts?**

7 A56. Yes. One such example of a recent coordination activity took place on July 17th,
8 followed by a more in-depth discussion on August 20th with the City of Ann Arbor.
9 These meetings included representatives of the City of Ann Arbor and its Planning
10 Commission, along with the management representative of the Company's
11 Engineering, Regional Planning Management, and Public Affairs organizations.
12 During these meetings, the Company explained the overall plan for infrastructure
13 improvement in the City of Ann Arbor, high level scope of projects, and a schedule
14 of these proposed projects. In reciprocity, the Ann Arbor leadership provided a
15 longer-term view of the development plan across the various neighborhoods of the
16 city. Through these dialogues, both the City of Ann Arbor and DTE Electric
17 achieved additional clarity of project scope and timing and were able to identify
18 key points of contact where additional follow up coordination could be beneficial
19 to facilitate an even greater level of collaboration and project execution efficiencies.

20

21 **Q57. What does Ann Arbor Witness Stults say about DTE Electric's efforts and**
22 **compliance with the order in Case No. U-21534 regarding community**
23 **coordination?**

24 A57. AA Witness Stults provided testimony that clearly states DTE Electric is compliant
25 (Direct Testimony of Stults pages 24 -25). She explains:

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1 *Q. Based on the City's experience, does DTE appear to be complying with the*
2 *Commission's directive regarding the Company's communication and*
3 *coordination efforts?*

4 *A. Yes. The Company has made efforts to align key projects in Ann Arbor with*
5 *the City's planned projects. DTE Electric and Ann Arbor have also*
6 *discussed ways to align aspects of the future coordination with increased*
7 *coordination efforts that DTE Gas and the City agreed to in the new*
8 *franchise agreement signed earlier this year. The City is hopeful that*
9 *having longer lead times for such coordination, which the City expects will*
10 *occur with more regular meetings, will lead to smoother execution for all*
11 *parties. In an effort to improve coordination efforts going forward, City*
12 *staff and Company representatives met in August to discuss how best to*
13 *coordinate in the future, including sharing planned infrastructure*
14 *upgrades, capital projects, and development review processes. The City*
15 *has already learned from these early efforts and discussions. The City*
16 *remains hopeful that a regular cadence of meetings with DTE regarding*
17 *coordination will allow efficiencies to be maximized and secure benefits for*
18 *ratepayers and taxpayers. In short, the City believes the Company is now*
19 *in compliance with the January Order and expects it will remain so.*

20

21 **Q58. Does the Company agree with AA Witness Stults?**

22 A58. Yes. The Company agrees with Witness Stults on this point.

23

24 **Q59. What does MAUI Witness Schultz recommend to the Commission in regard**
25 **to Community Coordination and does the Company agree?**

Line
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1 A59. Witness Schultz recommends the following as stated on pages 26–27, lines 20–3 of
2 his direct testimony:“ I recommend the Commission to consider requiring the
3 Company to document that it has reviewed the local government’s CIP and discuss
4 project prioritization and timing with local officials before it commits design capital
5 to a project. There should be reasonable exceptions to this rule, including projects
6 projected to cost less than \$250,000 net of customer contributions and emergent
7 and storm recovery expenses. Until the Company has completed these steps, it
8 should not advance a project beyond Stage 2 planning.”
9 The Company does not agree with this recommendation as it adds unnecessary
10 burden and does not contribute to the intended outcomes.

11

12 **Q60. In summary, what does the Company recommend to the Commission with**
13 **regard to Community Coordination?**

14 A60. The Company recommends that the Commission reject Witness Schultz’s proposal
15 to impose additional documentation requirements related to municipal
16 coordination. The Company has demonstrated compliance with existing
17 Commission expectations and continues to engage proactively with communities
18 through regular meetings and infrastructure planning discussions. The Company is
19 also sharing the progress of these projects in the public domain with tools such as
20 the Power Improvements Map. Additionally, the Company is taking steps to use
21 the State’s coordination tool, MIC, to further support infrastructure collaboration.
22 The Company believes its current coordination practices are reasonable and
23 effective, and that further mandates would be unnecessarily burdensome.

Line
No.

1 **Rebuttal Issue 9: ABATE Witness York Capital Reduction**

2 **Q61. What does ABATE Witness York recommend with respect to the distribution**
3 **base and strategic capital investments?**

4 A61. Witness York recommends that the Commission reduce \$829.311 million in capital
5 expenditures during the bridge period and the projected test year. This proposed
6 disallowance includes \$315.102 million in base capital and \$514.209 million in
7 strategic capital.³⁹

8

9 **Q62. Does the Company agree with Witness York's proposed disallowance of Base**
10 **Capital?**

11 A62. No, The Company disagrees. Please refer to Company Witness Hill's Rebuttal
12 Testimony, rebuttal issue number 5 regarding Base Capital. In summary, the
13 Company recommends the Commission reject ABATE Witness York's proposed
14 reduction in Emergent Replacements expenditures based on a five-year average
15 excluding 2021. The full five-year average is a prudent and historically approved
16 forecasting method. The Commission should also reject reductions tied to
17 removing constant dollar averaging and the composite inflation rate, also addressed
18 in in Witness Hill's Rebuttal testimony.

19

20 **Q63. How does Witness York calculate their Strategic Capital reduction?**

21 A63. Witness York calculates the proposed reduction by removing distribution strategic
22 capital projects that do not fall within the bridge year or the projected test year.⁴⁰

³⁹Direct Testimony of Witness York, page 17, Line 11

⁴⁰Direct Testimony of Witness York, pages 28-29, lines 15-7

Line
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1 **Q64. How does the Company respond to Witness York's proposed disallowance of**
2 **Strategic Capital, and what would be the impact of that disallowance?**

3 A64. The Company disagrees. Witness York's proposed reduction is based on projects
4 with in-service dates that fall outside the projected test year. As such, the reduction
5 has no impact on the Company's requested rate relief. Refer to Company Witness
6 Uzenski's rebuttal testimony for the accounting details related to the impact of these
7 reductions.

8

9 **Q65. Witness York conducts a supplemental calculation to support her proposed**
10 **disallowances for projects outside the bridge and projected test years, relying**
11 **on a five-year average of actual distribution capital expenditures (2020–2024).**
12 **Why is the use of a historical five-year average not a valid methodology for**
13 **forecasting strategic capital expenditures?**

14 A65. Using a five-year historical average of actual distribution capital expenditures
15 (2020–2024) is not a valid methodology for forecasting strategic capital
16 expenditures. This method oversimplifies planning by focusing on historical
17 trends, rather than incorporating specific, known, and measurable investments. It
18 fails to align capital forecasts with key objectives such as system reliability,
19 regulatory compliance, and customer service. As a result, this approach overlooks
20 the rigor of the Company's planning process and misrepresents the capital required
21 to meet future grid needs.

Line
No.

1 **Rebuttal Issue 10: Incorrect Claims Concerning Minimizing Equipment Failure**

2

3 **Q66. Witness Stephens, in addressing what he believes to be the cause of outages,**
4 **makes the statement that “the majority of time DTE customers spend without**
5 **power is due to vegetation contact, and to the wind that blows vegetation into**
6 **overhead lines (53%). Equipment failures also contribute, but to a much**
7 **smaller extent (11%, of which some amount are pole and poletop equipment**
8 **failures).”⁴¹ Do you agree with Witness Stephens’ characterization of the key**
9 **drivers of reliability?**

10 **A66. The Company agrees that vegetation is a significant cause of outages, which is why**
11 **the Company began the Tree Trim Surge program in 2019. However, the Company**
12 **believes that focusing solely on vegetation would not by itself address the complex**
13 **set of factors that influence distribution reliability.**

14

15 **Q67. What complex set of factors influence distribution reliability?**

16 **A67. The full analysis of grid reliability needs to address both the initiating event that**
17 **caused the outage (i.e., trees/wind) and the underlying equipment issues that have**
18 **nothing to do with trees/wind. As an example, system loading stress on already**
19 **aged and equipment, as we have seen this past summer, or a circuit which is on-**
20 **cycle for tree trimming could have an out of right of way tree that falls into the**
21 **lines. When this happens, the size of the outage and the extent of damage is**
22 **determined in part by the equipment that the tree encounters. If the equipment is**
23 **aged or built to a previous less-robust engineering and construction standard, the**
24 **tree will be more likely to break the equipment. However, if the circuit has been**

⁴¹ Direct Testimony of Witness Stephens, pages 13, lines 18-21

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1 rebuilt to the current stronger standard, with larger poles, stronger fiberglass cross
2 arms, and steel reinforced wire, the equipment would be hardened with greater
3 ability to withstand the more extreme weather conditions and damage will be
4 minimized.

5

6 **Q68. How does the current condition of the Company's distribution assets, and the**
7 **"bathtub curve" factor into the appropriate reliability approach?**

8 A68. The Company expects ongoing challenges as many grid assets approach the wear
9 out phase of the "bathtub curve," where failure rates rise sharply near the end of an
10 asset's useful service. If the Company does not invest in replacing its assets as
11 proposed by Witness Stephens, reliability declines and outages will worsen. Prior
12 investments have shown that improvements take time, so proactive and strategic
13 capital investments are essential to support continued safety, reliability, and
14 resiliency.

15

16 **Q69. What did the Audit Report observe and conclude regarding equipment**
17 **outages?**

18 A69. On page 90 of Part 1 of the Audit Report, Observation #6 states:

19 *"DTE's distribution lines contribute approximately 88 percent of SAIDI minutes.*
20 *Equipment caused outages were the greatest contributor to SAIDI on Blue Sky days*
21 *including storms causing less than 15,000 customer outages. This indicates the*
22 *condition of DTE Electric's distribution equipment requires improvement to reduce*
23 *SAIDI minutes."*

24

25 On page 40 of Part 2 of the Audit Report, part of Conclusion #15 states:

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1 “Distribution equipment failure has remained a major cause of outages for DTE.”

2

3 Additionally, the Audit Report substantiates its findings with a three-year trend of
4 customer interruptions by cause code.⁴² In the table below, equipment failures were
5 the largest cause of interruptions in 2022 and 2023 at 31.48% and 27.79%
6 respectively. In 2021, equipment failures were the second most prevalent cause at
7 21.04%. Furthermore, the table below shows a more detailed breakdown of causes
8 by separating tree and wind interruptions. This level of granularity offers a more
9 precise understanding of the underlying causes compared to the analysis presented
10 by Witness Stephens, which aggregates tree and wind interruptions into a single
11 category.

12

13 **Table 1 Number of Customer Interruptions by Cause**
14 **(Including MEDs)**

Cause Code by Year	2021		2022		2023	
Equipment Failure	752,702	21.04%	904,204	31.48%	906,649	27.79%
Tree	793,472	22.18%	508,376	17.70%	740,012	22.68%
Wind	212,297	5.93%	391,864	13.64%	706,454	21.65%
Weather (Lighting & Ice)	690,014	19.29%	115,097	4.01%	371,890	11.40%
Intentional	214,571	6.00%	163,167	5.68%	195,967	6.01%
Animal	95,736	2.68%	125,240	4.36%	130,172	3.99%
No Issues Found	160,433	4.48%	131,491	4.58%	118,026	3.62%
Public Interference	58,763	1.64%	73,999	2.58%	42,648	1.31%
Unknowns (removed in 2023)	211,208	5.90%	85,027	2.96%	23,646	0.72%
Equipment Loading	20,733	0.58%	12,650	0.44%	14,173	0.43%
Other	340,784	9.53%	348,794	12.14%	6,483	0.20%
Customer Equipment	1,308	0.04%	1,988	0.07%	4,876	0.15%
Meter/Blocks (new category)		0.00%		0.00%	1,422	0.04%
Switch	25,746	0.72%	10,555	0.37%	84	0.00%
Total	3,577,767		2,872,452		3,262,502	

DTE eliminated the Cause code “Unknown” in 2023 to better determine the causes of outages. The above data does not distinguish between overhead and underground equipment failures Causes of Interruptions – MEDs Excluded.

⁴² Audit Report, Part One, Page 85

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1 **Q70. In summary, what key factors should the Commission consider when assessing**
2 **claims from witnesses such as AG-MN Witness Stephens that equipment**
3 **failures play only a minor role in customer power outages?**

4 A70. The Commission should reject Witness Stephens' suggestion to focus exclusively
5 on tree trimming while disregarding strategic capital investments. Although
6 vegetation contact is a significant contributor to outages, and the Company initiated
7 the Tree Trim Surge program in 2019 to address this issue, the condition of
8 distribution equipment remains a critical factor in overall reliability. Equipment
9 failures, particularly as assets approach the wear out phase of the "bathtub curve,"
10 result in increased failure rates and can significantly worsen outage impacts.
11 Ongoing strategic capital investment is required to address the condition of
12 distribution equipment, which plays a critical role in supporting grid resiliency and
13 achieving reliability and safety standards.

14

15 **Rebuttal Issue 11: Distribution Investments to Increase Load-Serving Capacity Are**

16 **Determined by Peak Demand Rather than Energy Consumption.**

17

18 **Q71. On pages 37 lines 2-16 of his direct testimony, MNC Witness Jester contends**
19 **that the costs of the certain distribution system plant are not materially driven**
20 **by demand but by energy, consumed either throughout the year or during the**
21 **summer. Do you agree?**

22 A71. No. Total energy consumption (i.e., electricity usage over time) does not drive the
23 Company's sizing or investment decisions for distribution plants. Instead, the
24 Company designs and sizes its distribution facilities based on several key factors,
25 the most significant being peak demand—the highest electricity usage—within a
26 specific geographic service area and the continuous load carrying rating of the

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1 equipment. Additionally, the number of customers served in that area is also a
2 factor as it influences the coincident factor of the load carried by this equipment.
3 These factors—localized demand, geographic area, and customers served—are the
4 primary considerations in selecting and investing in distribution equipment. The
5 equipment must be capable of reliably serving the peak demand and customer base
6 in its designated area. Put differently, equipment cost is driven by demand,
7 customer count, and location-specific requirements, not by total energy
8 consumption.

9

10 **Q72. Does this conclude your rebuttal testimony?**

11 A72. Yes, it does.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of)
DTE ELECTRIC COMPANY)
for authority to increase its rates, amend)
its rate schedules and rules governing the)
distribution and supply of electric energy, and)
for miscellaneous accounting authority.)

Case No. U-21860

REBUTTAL TESTIMONY

OF

ALLEN J. KRYSCYNSKI

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DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF ALLEN J. KRYSCYNSKI

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1 **Q1. Please state your full name, business address and by whom you are employed?**

2 A1. My name is Allen J. Kryscynski (he/him/his), and my business address is One
3 Energy Plaza, Detroit, Michigan, 48226 and I am employed by DTE Electric
4 Company.

5

6 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
7 **Company (DTE Electric or Company)?**

8 A2. Yes.

9

10 **Purpose of Testimony**

11 **Q3. What is the purpose of your rebuttal testimony?**

12 A3. The purpose of this testimony is to respond to or rebut certain positions of:

- 13 • Michigan Public Service Commission (MPSC or Commission) Staff (Staff)
- 14 Witness Jessica Duell
- 15 • Staff Witness Shannon Rueckert
- 16 • Staff Witness Joseph Ufolla
- 17 • Attorney General (AG), Michigan Environmental Council (MEC), Natural
- 18 Resource Defense Council (NRDC), collectively AG-MN Witness Paul
- 19 Alvarez
- 20 • AG-MN Witness Dennis Stephens
- 21 • Attorney General (AG) Witness Sebastian Coppola
- 22 • Natural Resource Defense Council (NRDC), Citizens Utility Board of
- 23 Michigan (CUB), collectively NRDC-CUB Witness Richard Bunch

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- 1 • Michigan Environmental Council (MEC), Natural Resources Defense
- 2 Council (NRDC), and Citizens Utility Board of Michigan (CUB),
- 3 collectively MNC Witness Douglas Jester
- 4 • Soulardarity and We Want Green, Too, collectively Detroit Area Advocacy
- 5 Organization (DAAO) Witness Shimekia Nichols
- 6 • DAAO Witness Yunus Kinkhabwala, PhD
- 7 • DAAO Witness Toyia Watts
- 8 • The Ecology Center, The Environmental Law & Policy Center, Union of
- 9 Concerned Scientists, and Vote Solar, collectively CEO Witness Boratha
- 10 Tan
- 11 • CEO Witness William Kenworthy

12

13 **Q4. Are you sponsoring any exhibits in this proceeding?**

14 A4. Yes. I am sponsoring the following exhibits:

15	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
16	A-46	LL1	DR STDE 3.10a, 3.11
17	A-46	LL2	DR MNSCDE 5.11aix
18	A-46	LL3	DR U-21297 MNSCDE-2.1
19	A-46	LL4	DR MNSCDE-3.47 Effectiveness Curves

20

21 **Q5. How is your testimony organized?**

22 A5. My testimony is organized around several key themes that emerged in the

23 testimonies of Staff and intervenor witnesses. For each topic area listed in the Table

24 of Contents, I will provide a detailed discussion that rebuts the specific inaccuracies

25 and/or erroneous assumptions presented in their testimony. I will also explain why

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1 certain recommendations made by these witnesses should not be adopted by the
2 Commission.

3
4 The absence of a discussion of other matters in my testimony should not be
5 regarded as an indication that I agree with all other aspects of the Staff's and
6 intervenors' testimony.

7

8 **Rebuttal Issue 1: Distribution O&M**

9 Staff O&M Discussion

10 **Q6. What Distribution O&M expense amount did Staff Witness Rueckert**
11 **recommend for approval?**

12 A6. Starting from the Company's submitted Exhibit A-13 Schedule C5.6, with 2023 as
13 the historic test year, Witness Rueckert states that "Staff recommends that the
14 Commission approve a total Distribution expense projection of \$502,290,[000]
15 based on the most current information available to the Company and Staff's
16 inflation rates supported by Staff Witness Ufolla. This is a downward adjustment
17 of \$3,223,000 from the Company's request of \$505,513,000".¹

18

19 **Q7. What is the source of the downward adjustment of \$3.223 million?**

20 A7. Witness Rueckert's support for this downward adjustment arises from lower
21 inflation rates than the rates used by the Company. The Staff inflation rate itself is
22 supported by Witness Ufolla.

¹ Rueckert Amended DT, page 7, lines 9-12, original quote used \$502,290 in line with the exhibit convention which is shown in the thousands of dollars. The quote was edited by adding three extra zeros for clarity – now showing \$502,290,000.

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1 **Q8. Does the Company agree with this downward adjustment?**

2 A8. No. The Company does not agree with the inflation rate disallowance. As presented
3 by Company Witness Uzenski in her direct testimony on pages 35-36 and further
4 supported by Company Witness Bruzzano in his rebuttal testimony, the Company's
5 estimated level of inflation for 2025 is 3.00% and 2026 is 3.10%.

6

7 **Q9. Other than the inflation adjustment, did Staff recommend disallowances for**
8 **any other Distribution O&M expense?**

9 A9. No.

10

11 **Q10. How does the Company respond to Staff Witness Duell's request for the**
12 **Company to provide additional support and explanation for storm restoration**
13 **O&M expenses in future rate cases?²**

14 A10. The Company will provide added support and increased detail for storm restoration
15 O&M expenses in future rate cases as requested. Additionally, in discovery (STDE-
16 3.10a and 3.11) in this case, the Company provided additional information on storm
17 restoration O&M expenses in response to Witness Duell's requests.³

18

19 AG Witness Coppola Disallowances

20 **Q11. For ease of reference, can you please clarify the different terminologies used**
21 **by AG Witness Coppola and how they relate to your direct testimony and**
22 **exhibits?**

23 A11. Yes, I offer three points of clarification:

² Duell, page 10, lines 5-13

³ Exhibit A-46 Scheule LL1

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1 1) The term “normalization adjustments” is what the Company uses in the
2 Exhibit A-13 Schedule C5.6 to categorize a specific type of O&M changes
3 needed to adjust the historic test year to reach a normal or average annual
4 spending amount. An example would be an adjustment upwards to account
5 for the unusually low number of apprentice classes in 2024 compared to the
6 normal level of classes in a typical year.

7 2) The term “other projected adjustments” are additions to O&M that the
8 Company identified that are new or additional O&M beyond the historic
9 test year. An example would include additional PTMM inspection dollars
10 needed to achieve a 5-year cycle recommended by the Liberty Audit Report
11 that were not previously included as part of past A-13 exhibits.

12 3) In the Exhibit A-13 Schedule C5.6, the term “workforce augmentation” is
13 used when discussing the other projected adjustment needed for additional
14 engineering staff. Witness Coppola refers to the same adjustment as
15 “engineering and support staff”. For consistency and clarity, this document
16 will adopt Witness Coppola’s terminology and refer to the adjustment as
17 engineering and support staff.

18

19 **Q12. What does Witness Coppola recommend regarding the Company’s**
20 **Distribution O&M expense?**

21 A12. Witness Coppola uses 2024 as his historical test period in Exhibit AG-41 to support
22 his O&M disallowance recommendations. His analysis builds upon the Company’s
23 discovery response MNSCDE-3.16, which is presented in his Exhibit AG-40. That
24 discovery response uses 2024 as the starting point, resulting in a baseline that is
25 \$8.087 million lower than the Company’s Exhibit A-13 Schedule C5.6, which used

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2023 as the historical period. In addition to this reduction, Witness Coppola's Exhibit AG-41 introduces further reductions by rejecting or modifying all the Company's "normalization adjustments" and several "other projected adjustments". His recommendations amount to a total disallowance of \$62.581 million.

Table 1 summarizes Witness Coppola's proposed disallowances:

Table 1 Witness Coppola O&M Disallowance Summary

Disallowance Category	Description	Disallowance Amount
Base Year Alternative	Change from 2023 A-13 to 2024 A-13	\$8.087M
Normalization Adjustment	Hiring pause	\$1.758M
Normalization Adjustment	Apprentice classes pause	\$0.576M
Normalization Adjustment	Temporary pause in purchases of non-critical safety materials and advertising	\$1.735M
Normalization Adjustment	Temporary reduction in consulting spend	\$2.128M
Normalization Adjustment	Storm Restoration	\$12.044M
Other Projected Adjustment	Tree Trim	\$8.322M
Other Projected Adjustment	Preventative Maintenance Backlog	\$7.300M
Other Projected Adjustment	Corrective Maintenance	\$7.300M
Other Projected Adjustment	Staking Rate Increase	\$1.618M
Other Projected Adjustment	Engineering and Support Staff	\$8.328M
Inflation	Inflation Rate Change	\$3.384M
Total Disallowance		\$62.581M

In the testimony that follows, I discuss Witness Coppola's normalization adjustments, other projected adjustments, and inflation adjustment in the order

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1 shown in the table and explain that Witness Coppola's disallowances are either
2 unsupported, flawed, or both, and should be rejected.

3

4 **Q13. What is Witness Coppola's rationale for rejecting normalization amounts for**
5 **the Company's hiring pause, apprentice class pause, non-critical safety**
6 **materials and advertising pause, and temporary reduction in consulting**
7 **spend, which total \$6.197 million?**

8 A13. Witness Coppola claims that, "[i]f the Company can function for two years, 2023
9 and 2024, without incurring those expenses, they should not occur in subsequent
10 years and into the projected test year".⁴ Other than these two unsupported
11 statements, Witness Coppola provides no further rationale or evidence for why
12 these four proposed normalizations should be rejected.

13

14 **Q14. Is Witness Coppola's rationale sound?**

15 A14. No. Witness Coppola's explanation has a significant flaw. He assumes that just
16 because the Company has been able to forgo an expense for a period of two years
17 it will be able to forgo that expense indefinitely. This is not always the case. Take
18 an automobile for example, just because you have not changed the oil in your car
19 for the last two years does not mean you never need to do it again. Foregoing an
20 expense in many situations creates greater urgency for the expense in the future.
21 This is the case for all of the Company's normalizations adjustments.

22

23 **Q15. Why are the amounts the Company proposed appropriate?**

24 A15. I will explain the need for each proposed normalization adjustment below:

⁴ Witness Coppola, page 109, lines 19-21

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1 Hiring Pause – The Company implemented a hiring pause as a short-term measure
2 to support temporary cost reductions but does not agree with the assertion that a
3 sustained hiring pause can be maintained over the long term without adverse
4 impacts. The workforce requirements are determined based on current and
5 anticipated business needs, attrition, and the ongoing requirement to maintain safe,
6 reliable, and efficient service to customers. Reduced O&M expenses, if extended
7 indefinitely as Witness Coppola suggests, would constrain the Company’s ability
8 to respond to emergent challenges, implement new initiatives, and maintain critical
9 infrastructure. This normalization returns Distribution Operations to a 2022
10 personnel level.

11

12 Apprentice Classes Pause – As in many occupations, filling the long-term
13 workforce needs for Overhead and Underground field employees requires planning
14 in advance for estimated future needs, as there is a long training period before an
15 entry level employee becomes certified to work independently.⁵ As part of the
16 hiring pause, the Company instituted a temporary reduction down to two apprentice
17 classes in 2024. The Company expects to have five apprentice classes in 2025, with
18 the potential to accelerate an additional class in December should planned
19 operational needs require it. The Company has planned the same number of classes
20 in 2026 as 2025. Failure to bring apprentice programs back up to pre-2024 levels
21 would jeopardize the Company’s ability to replace field employees; a material

⁵ “The Company’s field personnel are highly trained and experienced skilled trades workers. They must complete apprenticeships (4-6 years, depending on trade) and must consistently demonstrate competence and sound judgment to earn their professional certifications from the U.S. Department of Labor and the International Brotherhood of Electrical Workers (IBEW).” Hill U-21534 Rebuttal Testimony, page 27, lines 19-23

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1 percentage of current Overhead and Underground resources are eligible to retire
2 within the next five years.

3

4 Temporary Reduction in Consulting Spend – Consultants allow the Company to
5 flexibly support short term priority needs and temper the need to hire more full-
6 time staff. While temporary reductions have helped manage short-term priorities,
7 these reductions are not viable as a long-term strategy. Contractor support remains
8 essential to sustaining core operations, ensuring continuity of business functions,
9 and maintaining compliance and performance standards.

10

11 Pause in Purchases of Non-Critical Safety Materials and Advertising – The
12 Company instituted reductions in purchases of non-critical safety materials and
13 storm advertising as a temporary measure implemented to address short-term
14 budgetary constraints. Storm advertising delivers corporate safety communications
15 through the use of social media and other media outlets. These reductions were
16 made possible, in part, due to below average storm volumes in the second half of
17 2023 and calendar year 2024. However, this approach is not sustainable over the
18 long run given the unpredictable nature of future storm activity and the critical
19 importance of maintaining public safety. Ongoing procurement is essential to
20 support operational continuity of storm response and storm advertising supports
21 public safety.

22

23 **Q16. What is the Company's proposed O&M restoration normalization amount**
24 **and how does it compare with Witness Coppola's recommended restoration**
25 **normalization?**

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1 A16. The Company calculated a \$35.828 million normalization, in the Exhibit A-13
2 Schedule C5.6, to adjust spending levels to the restoration five-year storm average.
3 Witness Coppola proposes a normalization value of \$23.784 million, and a
4 disallowance of \$12.044 million.⁶

5
6 **Q17. Does the Company agree with Witness Coppola's methodology to calculate an**
7 **updated restoration normalization, and should his disallowance be rejected?**

8 A17. The Company does not agree with Witness Coppola's calculation for the restoration
9 normalization. Company Witness Lyons defends the use of constant dollar average
10 (CDA) in his direct and rebuttal testimony. CDA as noted in Company Witness
11 Lyons direct testimony on page 4, constant dollar averaging of historical costs – or
12 inflation adjusting of historical costs – is a necessary step in developing cost
13 forecasts because inflation over time reduces the purchasing power of goods and
14 services. The Constant Dollar Averaging methodology adjusts historical
15 expenditures to a common-year dollar value, enhancing forecast accuracy and
16 ensuring future expenditure estimates reflect true labor and material costs.

17
18 The inflation rates used for the Exhibit A-13 Schedule C5.6 are presented by
19 Witness Uzenski in her revised direct testimony on pages 35-36 and further
20 supported by Company Witness Bruzzano in his rebuttal testimony, the Company's
21 estimated level of inflation for 2025 is 3.00% and 2026 is 3.10%. There are two
22 principal issues with Witness Coppola's methodology employed.

⁶ Coppola Exhibit AG-41

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1 First, Witness Coppola disregards the use of constant dollar averaging in
2 calculating the storm restoration portion. By omitting this approach, the resulting
3 normalization understates the true storm restoration average. The Company's
4 methodology for storm restoration O&M, approved by the Commission in the most
5 recent DTE Electric rate case appropriately accounts for the time value of money
6 by converting historical expenditures to a common baseline, specifically 2024
7 dollars.⁷ Furthermore, Company Witness Lyons presents a compelling case in both
8 his direct and rebuttal testimony supporting the use of CDA to forecast costs. He
9 clearly demonstrates the need to adjust historical spending to reflect current
10 economic conditions and validates CDA as a reasonable and appropriate
11 forecasting method. In addition, storm restoration expenses are primarily driven
12 by labor. Company Witnesses Lyons⁸ and Hill⁹ demonstrate in their direct and
13 rebuttal testimonies that the Company's methodology remains appropriate by
14 providing data on the volatility and consistent upward trend of both labor and
15 material expenditures, as requested by the Commission.
16
17 Second, Witness Coppola's calculation mistakenly fails to include the non-storm
18 restoration component which is considered part of the 5-year average. Applying
19 Witness Coppola's own methodology, without constant dollar averaging, an
20 additional \$1.495 million should have been included in his restoration
21 normalization amount.

⁷ "The Commission finds DTE Electric's storm restoration projection for the projected test year is supported in the record and is reasonable. Therefore, the Commission approves the projection." Case No. U-21534 Order dated 01/23/25, page 221.

⁸ Lyons DT Section VI and rebuttal testimony pages 5-6

⁹ Hill DT, pages 9-13 and rebuttal testimony Rebuttal Issue #2

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1 Because of incorrect assumptions, methodology, and calculation errors, the
2 \$12.044 million disallowance presented by Witness Coppola should be rejected. If,
3 however, the Commission determines that the constant dollar averaging
4 methodology should not be included in restoration O&M, the Commission should
5 modify Witness Coppola's disallowance to \$10.549 million to correct for the
6 expenses he incorrectly left out of his calculation.

7

8 **Q18. Do you agree with the proposed disallowances, a total of \$32.868 million that**
9 **Witness Coppola made for "other projected adjustments" as presented in**
10 **Table 1?**

11 A18. No. The Company does not agree with any of the proposed disallowances
12 recommended by Witness Coppola for other projected adjustments. Each
13 disallowance will be rebutted by the respective sponsoring witness as follows:

- 14 • Preventative Maintenance Backlog will be rebutted by Company Witness
15 Robinson
- 16 • Corrective Maintenance will be rebutted by Company Witness Robinson
- 17 • Tree Trim will be rebutted by Company Witness Steudle
- 18 • Staking and Locating will be rebutted by Company Witness Hill
- 19 • Engineering and Support Personnel will be rebutted in this testimony
20 (Company Witness Kryscynski)

21 The Company's position and supporting evidence for each adjustment will be
22 presented in the testimony of the listed witnesses.

23

24 **Q19. What is Witness Coppola's rationale for recommending a disallowance of the**
25 **\$8.328 million O&M request for engineering and support personnel?**

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1 A19. He claims that the Company failed to provide “supporting evidence” for the
2 increase in personnel and “the Company could not provide an historical perspective
3 of how many employees currently occupy those positions or occupied them in the
4 past five years. The Company also could not identify what new projects or
5 programs the new employees would work on.”¹⁰

6

7 **Q20. Did the Company provide supporting evidence for the increase in engineers**
8 **and support personnel to justify the requested \$8.328 million of O&M and**
9 **reject Witness Coppola’s disallowance?**

10 A20. Yes. A significant amount of evidence was provided to support this expense and,
11 as such, Witness Coppola’s disallowances should be rejected.

12

13 The Company has provided considerable evidence to support the increase, yet
14 Witness Coppola provides no explanation as to why this evidence still isn’t enough.
15 In my revised direct testimony, I explain that additional engineering and support
16 personnel are needed to address resource gaps and support initiatives including
17 automation efforts, incorporating Outage Management System accuracy
18 improvements, and distributed energy resources integration, all of which reflect the
19 growing complexity and scale of the distribution system.¹¹ As explained in
20 discovery response MNSCDE-5.11aix (Exhibit A-46, Schedule LL2), the
21 Company is not able to provide a historical perspective of how many employees
22 occupied these specific new positions in the past five years because the positions
23 requested are in fact newly created positions; therefore, no historical data exists for
24 these roles. Furthermore, as the Company explained in discovery, included in

¹⁰ Coppola, page 59, lines 3-6, line 14

¹¹ Kryscynski Revised DT, page 13, lines 20-25 – page 14 – page 15, lines 1-18

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1 Witness Coppola's Exhibit AG-16, an increase in engineering and support
2 personnel is intended to address multiple projects and programs, with specific
3 assignments determined by the operational needs of the Company at the time of
4 employment. It's important to note that the Company's Distribution engineers
5 support all the Company's distribution capital and O&M activities so new
6 employees have the possibility to be assigned to support any project – and will
7 likely be supporting multiple projects in some capacity. These assignments will
8 change over time as projects are added and completed.

9
10 To further support the necessity and allocation of these positions, a detailed
11 operations headcount requirements list, broken down job category, type, expected
12 cost, and individual role, was provided in discovery which is included in Witness
13 Coppola Exhibit AG-16 for all 209 forecasted hires. To say that the Company did
14 not provide ample support for these positions is simply untrue.

15

16 **Q21. Does Witness Coppola also propose an associated capital disallowance for**
17 **engineering and support personnel?**

18 A21. Yes. Using the same lack of supporting evidence argument, Witness Coppola
19 recommends "that the Commission remove the \$16,888,000 and \$5,630,000 from
20 the Company's forecasted capital expenditures for 2025 and 2026, respectively".¹²
21 Witness Coppola indicates that the total amount, \$22,518,000 is the capital portion
22 of the 209 additional employees the Company plans to hire.

23

¹² Coppola, page 59, lines 15-16

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1 **Q22. Did the Company request an additional \$22.518 million in capital for**
2 **engineering and support personnel?**

3 A22. No. As part of the projects that support the increasing investment in the grid, the
4 capital required is already accounted for in the Company's A-12 Exhibit request as
5 part of the Company's capital support overheads. However, without increasing
6 internal engineering and support staff, the Company would be required to increase
7 its reliance on both contractors and overtime to maintain essential operations,
8 support and manage capital project needs. Not filling the additional 209 positions
9 would not avoid this required capital investment.

10

11 **Q23. What should the Commission do with respect to Witness Coppola's capital**
12 **disallowance of the engineering and support personnel investment?**

13 A23. The Commission should reject Witness Coppola's proposed disallowance of capital
14 investment in engineering and support personnel. As previously discussed, the
15 Company has provided substantial evidence demonstrating the necessity of these
16 roles. Moreover, the capital investment associated with these functions will be
17 required regardless of whether the new positions are ultimately filled.

18

19 **Q24. Does the Audit Report submitted by Liberty Consulting on September 23,**
20 **2024 concerning DTE Electric in Case No. U-21305 support the need for**
21 **additional engineers?**

22 A24. Yes. The Audit Report states "The very large reliability programs it will take to
23 reach DTE's reliability targets appear to require significantly more engineering
24 resources than exist now. The inability to provide them not only risks significant
25 delay in program execution, but in effectiveness and efficiency if engineering and

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1 design do not produce necessary support to meet expectations that form the basis
2 for committing field resources”.¹³
3

4 **Q25. Were there any proposed Distribution O&M disallowances based on inflation**
5 **factors?**

6 A25. Yes. Witness Coppola rejected the Company proposed inflation rate and applied a
7 new rate of 2.80% for 2025 and 2.40% for 2026 to adjust to the projected test year
8 2026 in his Exhibit AG-41. This resulted in an inflation disallowance of \$3.384
9 million. The Company maintains that its recommended rates are most appropriate
10 for this case, and the Commission should reject Witness Coppola’s proposed
11 inflation disallowance. Inflation rates are presented by Company Witness Uzenski
12 in her direct testimony on pages 35-36 and further supported by Company Witness
13 Bruzzano’s in his rebuttal testimony.
14

15 MNC Witness Jester O&M Disallowance

16 **Q26. What does MNC Witness Jester propose for the O&M restoration**
17 **normalization methodology?**

18 A26. Witness Jester proposes the use of cost projections based on a simple historical
19 average instead of using constant dollar averaging for the storm restoration
20 expense.¹⁴
21

22 **Q27. Does the Company agree with Witness Jester’s methodology to calculate the**
23 **restoration normalization?**

¹³ Case No. U-21305, Dkt. Nos. 12, 13 (the “Audit Report”), Part II, page 15

¹⁴ Jester, page 20, lines 11-13

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1 A27. No. The Company does not agree with Witness Jester's methodology for the
2 restoration normalization. Company Witness Lyons' defends the use of constant
3 dollar average (CDA) in his direct and rebuttal testimony.

4
5 By omitting this approach, it understates the true storm restoration average. The
6 Company's methodology for storm restoration O&M, approved by the Commission
7 in the most recent DTE Electric rate case appropriately accounts for the time value
8 of money by converting historical expenditures to a common baseline, specifically
9 2024 dollars.¹⁵

10

11 Furthermore, Company Witness Lyons presents a compelling case in both his direct
12 and rebuttal testimony supporting the use of CDA to forecast costs. He clearly
13 demonstrates the need to adjust historical spending to reflect current economic
14 conditions and validates CDA as a reasonable and appropriate forecasting method.
15 In addition, storm restoration expenses are primarily driven by labor. Company
16 Witnesses Lyons¹⁶ and Hill¹⁷ demonstrate in their direct and rebuttal testimonies
17 that the Company's methodology remains appropriate by providing data on the
18 volatility and consistent upward trend of both labor and material expenditures, as
19 requested by the Commission.

¹⁵ "The Commission finds DTE Electric's storm restoration projection for the projected test year is supported in the record and is reasonable. Therefore, the Commission approves the projection." Case No. U-21534 Order dated 01/23/25, page 221.

¹⁶ Lyons DT Section VI and rebuttal testimony pages 5-6

¹⁷ Hill DT, pages 9-13 and rebuttal testimony Rebuttal Issue #2

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1 NRDC-CUB Witness Bunch O&M Disallowances and Securitization

2 **Q28. Can you summarize Witness Bunch’s proposal for Distribution O&M?**

3 A28. Yes. Witness Bunch generally acknowledges the Company’s need to spend the
4 requested level of Distribution O&M. However, he believes the Commission
5 should defer “surge” O&M requests and part of the Company’s proposed inflation
6 O&M request, with the deferred expenses being securitized to minimize rate impact
7 to customers¹⁸. While Witness Bunch refers to these items as deferrals in this
8 testimony¹⁹, they are functionally disallowances because they result in a dollar-for-
9 dollar reduction in the Company’s O&M request in this case. For consistency, I will
10 refer to them as disallowances throughout my testimony. Witness Bunch’s
11 proposal used a reconstructed version of the Company’s Exhibit A-13 that averages
12 the Schedule C5.6 from that Exhibit and the discovery response MNSCDE-3.16
13 which is found in Witness Coppola’s Exhibit AG-40.²⁰

14

15 **Q29. What are the Distribution O&M “other projected adjustments” and inflation**
16 **that Witness Bunch proposes be disallowed?**

17 A29. Below is a table of Witness Bunch’s proposals for disallowance that totals \$49.367
18 million.

19

Table 2 Witness Bunch O&M Deferral

Disallowance Category	Description	Disallowance/ Securitization Amount
Other Projected Adjustment	Preventative Maintenance Backlog	\$7.300M
Other Projected Adjustment	PTMM - Pole Top Inspections	\$2.400M

¹⁸ The “surge” approach was presented by MNC Witness Jester on pages 29-34 of his DT. Refer to Company Witness Chiu who addresses the surge proposal.

¹⁹ Bunch DT, page 48, lines 8-10

²⁰ Bunch Exhibit CUB 34

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Disallowance Category	Description	Disallowance/ Securitization Amount
Other Projected Adjustment	PTMM - Pole Inspections	\$6.200M
Other Projected Adjustment	PTMM - Infrared Thermography	\$1.900M
Other Projected Adjustment	Corrective Maintenance	\$7.300M
Other Projected Adjustment	Engineering and Support Staff	\$8.300M
Inflation	Inflation Rate Change	\$15.967M
Total Disallowance Securitization		\$49.367M

1 **Q30. What are the main reasons for Witness Bunch's proposal to disallow portions**
2 **of the Company's inflation-adjusted O&M request?**

3 A30. Witness Bunch's proposal to disallow portions of the Company's inflation-adjusted
4 O&M request is based on two main arguments. First, he removes the 2024 inflation
5 adjustment based on a combined Exhibit A-13 Schedule C5.6 and the discovery
6 response MNSCDE-3.16, which is found in Witness Coppola's Exhibit AG-40, as
7 his baseline.²¹ Second, for subsequent years (2025 bridge year and 2026 test year),
8 he calculates inflation adjustments by using a productivity-adjusted inflation factor
9 rather than the Company's proposed rates.

10

11 **Q31. How does the Company respond to Witness Bunch's proposal to disallow**
12 **portions of the inflation-adjusted O&M request?**

13 A31. The Company maintains that its proposed inflation rates, 3.00% for 2025, and
14 3.10% for 2026 are the most appropriate for this case and the Commission should
15 reject Witness Bunch's proposed inflation disallowance. Appropriate views

²¹Bunch Exhibit CUB-34

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1 concerning inflation are addressed by Company Witness Uzenski in her revised
2 direct testimony on pages 35-36 and further supported by Company Witness
3 Bruzzano in his rebuttal testimony,

4

5 **Q32. What is the main reason for Witness Bunch's proposal to disallow other**
6 **projected adjustments?**

7 A32. Witness Bunch's main reason for recommending disallowance of other projected
8 adjustments is that "they appear to be a result of, at least in part, historical deferred
9 maintenance of DTEE distribution system" and he therefore proposes they be
10 deferred for "surge" treatment.²²

11

12 **Q33. How does the Company respond to Witness Bunch's characterization of**
13 **projected O&M adjustments as "surge" spending and his recommendation for**
14 **disallowance?**

15 A33. The Company disagrees with Witness Bunch's characterization and proposed
16 disallowance. As explained in the rebuttal testimony of Witness Chiu, this increase
17 is not a temporary anomaly but a deliberate and sustained investment strategy to
18 improve reliability.

19

20 **Q34. Can you explain why Witness Bunch's characterization of these other**
21 **projected adjustments is not supportable?**

22 A34. Yes. I detail the reasons why Witness Bunch's views should be rejected below:

23 a. Preventative Maintenance (PM) Backlog – This expense is needed, in part,
24 to sustain a new level of PM inspections going forward and, in part, to

²² Bunch, page 31, lines 7-8

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1 reduce the current backlog. While the portion of the expense that is
2 dedicated to the backlog reduction is short in duration, the total cost to
3 address it is too small to warrant securitization. See Company Witness
4 Robinson's revised direct testimony pages 42-45 for specific cost details.

5 b. PTMM Inspections (all three sub-categories) – These expenses will support
6 increased levels of inspections that will be sustained at the requested level
7 going forward. See Company Witness Robinson's revised direct testimony
8 pages 33-34 for details.

9 c. Corrective Maintenance – This expense is needed to sustain a new level of
10 PM inspections going forward. See Company Witness Robinson's revised
11 direct testimony page 42 for details.

12 d. Engineering and Support Staff – This expense will support new personnel
13 and is needed for the foreseeable future, thus not short in duration, hence,
14 not appropriate for a "surge". See my revised direct testimony pages 13-15
15 for details.

16

17 **Q35. Does Witness Bunch propose any recommendations beyond disallowance and**
18 **deferral of these costs?**

19 A35. Yes. In addition to recommending deferral of certain projected O&M costs, Witness
20 Bunch proposes that the Commission consider securitizing these expenditures²³.

21

22 **Q36. How does the Company respond to this proposal?**

23 A36. The Company disagrees with Witness Bunch's recommendation to securitize
24 projected O&M adjustments and inflation. Company Witness Lepczyk rebuts the

²³ Bunch, page 48, lines 8-10

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1 notion that securitization is an appropriate financing mechanism for routine and
2 recurring investments in the distribution system.

3 **Q37. Does Witness Bunch contest the Company's need for this additional O&M**
4 **funding?**

5 A37. No. Witness Bunch clearly states that he is not trying to prevent the Company from
6 spending the requested dollars to improve the safety and reliability of its
7 distribution system.²⁴

8
9 **Q38. What is the Company's recommendation for Distribution O&M expenses?**

10 A38. The Company recommends that the Commission:

- 11 • Adopt Staff's recommendation for Distribution O&M updated for the inflation
- 12 rates supported by Witness Bruzzano in rebuttal testimony.
- 13 • Reject all AG Witness Coppola's proposed disallowances as unsupported.
- 14 • Reject MNC Witness Jester's recommendation to exclude CDA when
- 15 determining storm restoration expense
- 16 • Reject NRDC-CUB Witness Bunch's disallowances and deferral/securitization
- 17 plan as unnecessary and inappropriate for the expenses requested.

18

19 **Rebuttal Issue 2: Global Prioritization Model (GPM)**

20 **Q39. Do witnesses express concerns about the use of the GPM and Reliability Model**
21 **in their testimony?**

22 A39. Yes, most of the intervenor testimony discussion of these two models is done by
23 AG-MN Witness Alvarez. Among other arguments, he continues to claim that these

²⁴ Witness Bunch page 33, lines 1-9

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1 models are subjective, do not rely on historical analysis, and are not useful in
2 prioritizing capital expenditures.²⁵ There are a few common weaknesses that a
3 majority of Witness Alvarez's arguments rest upon. These are:

- 4 1) He omits key relevant information provided by the Company that
5 refutes his positions
- 6 2) He makes errors in calculations or mischaracterizes how the model
7 works
- 8 3) He oversimplifies the complexity of planning grid investments
- 9 4) He relies simply on his opinion instead of data and analysis

10

11 **Q40. What concerns does the Company have with AG-MN Witness Alvarez's claims**
12 **about the Company's GPM and its use?**

13 A40. Witness Alvarez makes several claims with regards to the GPM and its use.
14 Namely:

- 15 1) He claims he will address the Auditor's perspective on the GPM²⁶, however,
16 the testimony lacks any direct reference to the Auditor, leaving it unclear
17 how this perspective is incorporated or substantiated
- 18 2) He claims that a drawback of the GPM is that it cannot produce an optimal
19 size of the capital plan²⁷
- 20 3) He continues to claim that the GPM is subjective, despite evidence to the
21 contrary²⁸

22 I will discuss why each of these claims have little merit and undermine his critique
23 of the GPM.

²⁵ Alvarez Case No. U-21534, pages 44-46

²⁶ Alvarez, page 22, lines 2-3

²⁷ Alvarez, page 25, lines 7-9

²⁸ Alvarez, page 24, lines 17-18

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1 **Q41. Did Witness Alvarez use the Audit Report to support his position?**

2 A41. While he mentioned the Audit, he did not provide any specific references regarding
3 the GPM from the Audit Report.
4

5 **Q42. What did the Audit say about the GPM?**

6 A42. The Auditor's conclusion states "We found DTE's modeling used for evaluating,
7 comparing, and prioritizing reliability initiatives sound. DTE's Global
8 Prioritization model, which systematically compares and evaluates competing
9 system improvement and reliability-enhancing projects and programs across 10
10 important improvement dimensions, seems a balanced and logical application of
11 the "best fit, most reasonable cost" economic approach to investment optimization.
12 Its application at DTE is consistent with other utility strategic investment good
13 practices that Liberty has experienced."²⁹
14

15 **Q43. Did the Commission find any reason to modify the Company's GPM in the last**
16 **rate case?**

17 A43. No. The Commission states with respect to both the GPM and the Reliability
18 Model, "the Commission does not find it necessary to direct the company to
19 undertake broad changes to its modeling efforts."³⁰
20

21 **Q44. What does Witness Alvarez opine regarding DTE shareholder "concerns"?**

²⁹ Case No. U-21305, Audit Report, Part II, pages 24-25

³⁰ Case No. U-21534 Order dated 01/23/25, page 98

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1 A44. He states that “DTE Shareholders are not concerned with project or program cost-
2 effectiveness” and implies any capital project would be approved if it increases
3 earnings.³¹

4
5 **Q45. Is this an accurate representation of how capital projects and investments are**
6 **selected?**

7 A45. No. First, Witness Alvarez’s statement reflects his personal opinion and is not
8 supported by any evidence on the record. Second, it overlooks how the Company
9 manages the long-term needs of the grid as evidenced by the extensive detail
10 provided on GPM in Part II of my revised direct testimony.

11

12 **Q46. How does Witness Alvarez characterize how the Company develops the level**
13 **of annual capital investment?**

14 A46. He states, “It appears that the amount of capital spending the Commission
15 authorizes determines how far down the list DTE implements.”³²

16

17 **Q47. Does Witness Alvarez’s characterization reflect the complexities of how the**
18 **Company’s distribution investment plan is developed?**

19 A47. No. This is a major oversimplification and mischaracterization of the capital
20 planning process. As discussed in my revised direct testimony and several
21 Distribution Grid Plans, the Company’s engineers evaluate system needs and
22 conditions. Given the age of the infrastructure, reliability performance, and load
23 constraints present across the system, there are multiple competing needs to be
24 addressed. The Company then develops a plan that balances many factors,

³¹ Alvarez, page 25, lines 9-10

³² Alvarez, page 23, lines 3-4

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1 including capital availability, impact on rates, and resource availability, among
2 others.

3

4 **Q48. Does Witness Alvarez critique the GPM for not being able to develop an**
5 **‘optimal’ capital plan?**

6 A48. Yes. He states “there is no way to determine which projects or programs on the
7 prioritized list should be implemented, and therefore the optimal size of the capital
8 plan cannot be determined”.³³ He then suggests that all benefits should be
9 calculated in dollars.

10

11 **Q49. Do you agree with Witness Alvarez’s assertions?**

12 A49. No. Witness Alvarez again oversimplifies the Company’s planning process. In this
13 rate case alone, the Company has provided benefit-cost analysis (BCA) in several
14 areas, including the PTMM and Distribution Automation programs³⁴. Together,
15 these two areas represent over \$1.5 billion of investments, each demonstrating
16 benefits that exceed their costs. As the Company continues to expand the use of
17 BCAs across additional investment areas, it’s expected, given the current state of
18 the grid, that many future programs and projects will have benefit cost ratios
19 (BCRs) greater than one. The magnitude of the investments with a BCR greater
20 than one is much larger than what is reasonable to accomplish in a single year,
21 therefore a BCA alone does not determine what the optimal size of an annual plan
22 would be. As stated earlier, other factors such as resource availability, capital
23 availability, and impact on rates must be accounted for. Given the state of the

³³ Alvarez, page 25, lines 7-9

³⁴ Refer to Company Witness De Stigter’s direct testimony

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1 system and grid needs, the GPM is a valuable tool for prioritizing investments that
2 deliver the most value for the investment amount.

3

4 **Q50. What does Witness Alvarez claim regarding the dimensions in the GPM?**

5 A50. Witness Alvarez testifies that many of the eight characteristics overlap; he testifies
6 that the characteristic “reduction in duration of outage events” overlaps with the
7 characteristic “reduction in substation outage events that lead to a large amount of
8 stranded load for more than 24 hours”.³⁵

9

10 **Q51. How does the Company respond to this concern?**

11 A51. While various dimensions of the GPM are concerned with aspects of reliability,
12 they do measure different things. “Major Event Risk”, “SAIDI”, and “SAIFI”
13 dimensions all serve different purposes. As one example, the Major Event Risk
14 dimension provides a framework to prioritize investments that would avoid large
15 outages from substations failures. SAIDI and SAIFI improvements more typically
16 align with reducing outages on circuits, such as overhead outages and URD
17 outages. Additionally, the Company added SAIFI to the GPM in a previous
18 improvement update to complement SAIDI and provide a more complete picture
19 of the reliability experience. Some customers may experience a few long duration
20 outages which would be improved by SAIDI-targeting investments. Other
21 customers may experience short but frequent outages which would be improved by
22 SAIFI-targeting investments. Both duration and frequency measurements are
23 relevant to customer reliability.

³⁵ Alvarez, page 23, lines 9-12

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1 **Q52. How does Witness Alvarez characterize the data used to calculate GPM**
2 **scores?**

3 A52. He claims that “subject matter experts determine the scores for each characteristic
4 of a project or program” and that the scoring process is “completely subjective”.³⁶

6 **Q53. Is this an accurate assessment of the inputs to the GPM?**

7 A53. No. The Company would classify information in the GPM as either 1) objective; or
8 2) based on subject matter expertise. Objective data is based on a measurement or
9 observation and would not generally require any additional judgement or input.
10 Examples of this type of data are reliability data (SAIDI and SAIFI), wiredown
11 data, loading data, equipment ratings, event volume, and historical costs per event.
12 Other scoring may fall into the latter category, and are based on evaluations made
13 by individuals with specialized expertise.

15 **Q54. How would the Company describe the data used in the GPM?**

16 A54. The Company would describe the inputs shown in Table 3 below as predominantly
17 objective.

18 **Table 3 Classification of GPM Inputs**

19

Objective Inputs

- Historical reliability performance
- Historical wiredown performance
- Loading data
- Equipment ratings
- Stranded load calculations
- Demographic data such as inputs to the MiEJ Screen tool
- Historical trouble event volume
- Historical average costs per event
- Projected improvements in reliability, event volume, etc

Inputs based on subject matter expertise

- Scoring methodologies which combine multiple elements into a single value such as:
 - Asset health ratings
 - Load relief ratings
 - Overall MiEJ Screen score

³⁶ Alvarez, page 24, lines 15-16, line 18

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1 **Q55. What is the Company's assessment of the use of objective versus subject**
2 **matter expert inputs to the GPM model?**

3 A55. Table 4 below summarizes data from 157 investments scored in the GPM (Exhibit
4 A- 23 Schedules M14 and M14.1), with the total score by dimension and the total
5 score for all evaluated projects shown. The five bolded dimensions (Reduce
6 Electrical Hazards, SAIDI, SAIFI, O&M Avoidance and Capital Avoidance) are
7 entirely calculated based on objective information and contribute 56% of the overall
8 scoring. If contribution of the EJ Multiplier is included as objective, which uses the
9 MiEJ Screen score for the investment area and was developed for the state of
10 Michigan by the Department of Environment, Great Lakes and Energy (EGLE),
11 and contributes 23% to the total, 79% of the total scoring in the GPM is objective.
12 The dimensions that include some subject matter expertise, such as Overload Relief
13 and Capacity Relief, are also based on objective inputs such as measured load and
14 equipment ratings. In short, the Company's analysis of the data in the GPM shows
15 that Witness Alvarez's claim that GPM inputs are largely based on subjective
16 assessment and is not data-driven is incorrect.

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Table 4 Analysis of GPM input data

Impact Dimension	Objective Input	Subjective Input	Total by dimension	% of total
Reduce Electrical Hazards	x		3,694	16%
Overload Relief	x	x	1,448	6%
Capacity Relief	x	x	1,906	8%
Major Event Risk	x	x	1,627	7%
SAIDI	x		2,120	9%
SAIFI	x		1,782	8%
O&MAvoidance	x		3,512	15%
Capital Avoidance	x		2,030	9%
EJ Multiplier Adder	x	x	5,289	23%
Total Score			23,408	

2

3

Q56. Do any other intervenors raise concerns regarding the GPM?

5 A56. DAAO Witness Kinkhabwala discusses the EJ multiplier and is concerned that the
6 GPM will skew towards communities with few residential customers. He notes that
7 there could be hypothetical Project A with 500 EJ customers out of 1000 customers
8 served, which will receive a lower multiplier than a hypothetical project B with
9 only 50 residential customers, all of whom are EJ customers.³⁷ Witness
10 Kinkhabwala suggests that “upgrades should strongly weight absolute population
11 numbers and population density while considering EJ”.³⁸

12

Q57. Does the Company agree with this assessment?

14 A57. In short, no. While this is an interesting hypothetical argument, the Company does
15 not believe the problem actually exists in reality. First, an analysis which shows the
16 total residential customers impacted by a project in the GPM and compares it to the

³⁷ Kinkhabwala, page 43, lines 17-20³⁸ Kinkhabwala, page 44, lines 8-9

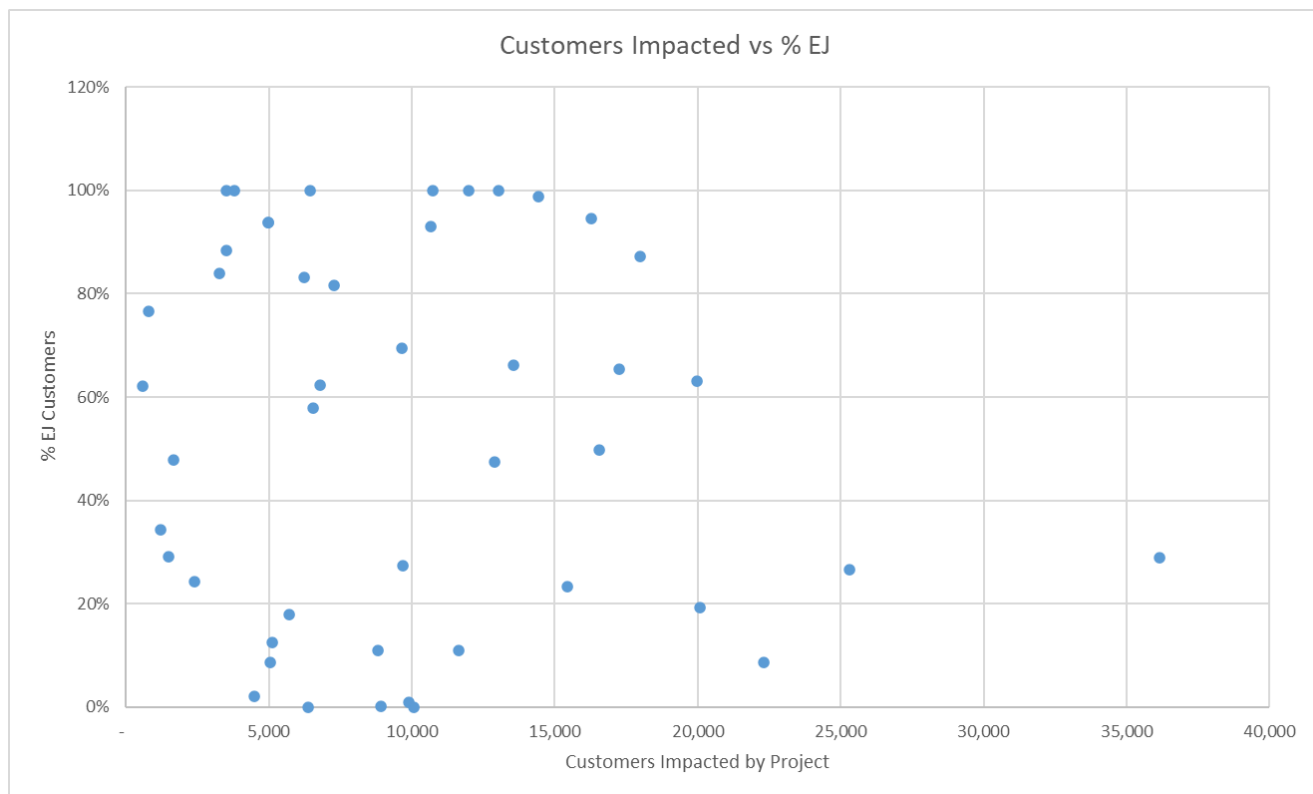
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1 percentage of EJ customers is shown in Figure 1 below. There is no apparent trend
2 between the number of customers impacted by a project and a declining EJ score.
3 In other words, of the current projects being evaluated, projects impacting more
4 customers do not necessarily have a lower EJ score. For projects impacting more
5 than 10,000 customers, there are more projects which serve >50% EJ customers
6 than there are with <50% EJ customers. Additionally, the Company believes that
7 the current method in the GPM accounts for differences in population size and
8 density. Benefits in the GPM are dollar weighted, where absolute benefits are
9 divided by the investment cost. Benefits from larger projects may be higher on an
10 absolute scale, however when benefits are divided by investment cost, which are
11 also higher for larger projects, the benefits per dollar investment score puts both
12 large and small projects on equal standing.

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Figure 1 Customers Impacted by investment vs % EJ Customers



2

3 **Rebuttal Issue 3: Reliability Model**

4 **Q58. What concerns does the Company have with AG-MN Witness Alvarez's claims**
5 **about the Company's Reliability Model?**

6 A58. Witness Alvarez makes several claims with regards to the Reliability Model, all of
7 which are either incorrect, based on incorrect analysis, omitting key data, over-
8 simplifying his analysis, or a lack of understanding of the underlying calculations
9 in the model. His major claims are:

10 1) Improvement assumptions are unvalidated;³⁹

³⁹ Alvarez, page 30, lines 15-18

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- 1 2) The model does not account for the impact of tree trimming versus the other
2 scope of work;⁴⁰
3 3) The baseline is “manipulated”;⁴¹
4 4) The model’s scaling from Ex-MED to All-weather performance is not in line
5 with historical performance;⁴² and
6 5) The output of the model is not validated.⁴³

7
8 **Q59. How does Witness Alvarez characterize reliability improvement assumptions?**

9 A59. He states that assumptions, particularly around 4.8kV Conversion and Distribution
10 Automation “are estimated by subject matter experts and not based on rigorous
11 analysis of historical project or pilot data.”⁴⁴ He quotes my revised direct testimony
12 as the basis for these statements.⁴⁵

13

14 **Q60. How would you characterize Witness Alvarez’s summarization of your revised**
15 **direct testimony?**

16 A60. Witness Alvarez’s summarization of my revised direct testimony is not accurate. In
17 fact, the Company does employ rigorous data analysis in the determination of
18 reliability improvements. In my revised testimony I stated: “For the automation and
19 4.8kV Conversion programs, the reliability improvement is based either on the
20 assessment from industry subject matter experts, including DTE Electric’s
21 Engineering, by comparing the newer programs to similar established programs, or

⁴⁰ Alvarez, page 31, lines 10-16

⁴¹ Alvarez, page 29, lines 20

⁴² Alvarez, page 32, lines 10-19 - page 33, lines 1-7

⁴³ Alvarez, page 32, lines 8-9

⁴⁴ Alvarez, page 30, lines 17-18 – page 31, line 1

⁴⁵ Kryscynski Revised DT, page 35, lines 13-17

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1 by using a smaller subset of circuit outage data”.⁴⁶ For the 4.8kV Conversion
2 reliability improvement, the Company uses all methods described to arrive at the
3 90% improvement assumption. It is based on historical circuit data from the Hilton
4 Road project, in comparison with the larger data set from the 4.8kV Hardening
5 program, and subject matter expertise on the improved resilience of the standard to
6 which the Company is constructing the circuits. Distribution Automation
7 improvement estimates are based on rigorous data analysis of historical outage
8 events and are supported by measured reliability benefits from recently deployed
9 reclosers.

10

11 **Q61. Does the Company agree with Witness Alvarez’s position that the Company**
12 **has not provided straightforward comparisons of historical data pre- and post-**
13 **project to quantify reliability risk reductions secured to date?**⁴⁷

14 A61. No. Witness Alvarez omits or disregards all the data that has been presented in this
15 case that provides a comparison of historical data pre- and post-project to quantify
16 reliability improvements. Most of the Reliability Model effectiveness calculations
17 are performed on historical data for three years prior to the investment, and as many
18 years post investment that are available. These calculations were provided by the
19 Company in discovery response MSNCDE-3.47.⁴⁸ Further discussion of the
20 benefits can be found in the testimonies of other Company witnesses. Company
21 Witness Stowe discusses the measured reliability improvements from 4.8kV
22 Conversion from the Hilton project in his revised direct testimony.⁴⁹ Company
23 Witness Rademacher discusses the measured benefits of the Distribution

⁴⁶ Kryscynski Revised DT, page 35, lines 13-17

⁴⁷ Alvarez, page 34, lines 1-2

⁴⁸ Exhibit A-46 Schedule LL4

⁴⁹ Stowe Revised DT, page 26, lines 21-25 – page 27, lines 1-9

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1 Automation reclosers deployed to date.⁵⁰ Company Witness Robinson's revised
2 direct testimony includes discussion of the benefits from 4.8kV Hardening and
3 Frequent Outage programs.⁵¹ In light of the volume of information the Company
4 has provided, the Commission should disregard Witness Alvarez's assertions
5 regarding the lack of information.

6

7 **Q62. Are there problems with the conclusions Witness Alvarez references regarding**
8 **4.8kV conversion effectiveness?**

9 A62. Yes. He references an analysis done by AG-MN Witness Stephens that claims
10 4.8kV reliability from 2018-2022 is 97 minutes, whereas 13.2kV reliability is 124
11 minutes, implying that because the 13.2kV has higher SAIDI, conversion from
12 4.8kV to 13.2kV will not improve reliability.⁵² It's important to note that Witness
13 Stephens based his analysis on data from two rate cases ago, despite having access
14 to updated data provided in discovery during this case.⁵³ There are two flaws to his
15 argument. First, the overall analysis must be inaccurate as the average system
16 performance over that time frame is 161 minutes. It is not mathematically possible
17 for both components of the distribution system to have reliability performance
18 below the system average. If this analysis was correct, the system average would
19 have to be below 132 minutes, it is clearly not. To use a simplistic example to
20 illustrate Witness Alvarez and Steven's error, if the system average is 100 and the
21 system only had two circuits, their testimony is effectively claiming that these
22 circuits could have values of 60 minutes and 80 minutes which is impossible.⁵⁴

⁵⁰ Rademacher Revised DT, page 23, lines 6-10

⁵¹ Robinson Revised DT, pages 11-13, page 14, lines 1-4, page 116, lines 2-14

⁵² Alvarez, page 31, lines 5-7

⁵³ Exhibit A-46 Schedule LL3

⁵⁴ Assuming the two circuits have equal numbers of customers, the average would be 70, effectively 30% shy of reality

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1 Second, comparing the historical reliability of 4.8kV and 13.2kV circuits is an
2 overly simplistic approach to estimating how a 4.8kV conversion project will
3 improve reliability. Parts of the 13.2kV system are decades old, and very little of it
4 has been built to our latest standard. Newly constructed 13.2kV circuits with
5 stronger poles and conductors are expected to perform much better than the 13.2kV
6 system on average. Actual measured reliability improvements from the Hilton Road
7 project have resulted in a 72% reduction in all-weather SAIDI.⁵⁵

8

9 **Q63. How does Witness Alvarez characterize the impact of tree trimming and**
10 **related outages versus non-tree related outages?**

11 A63. He claims that it is difficult to determine if reliability improvement is due to tree
12 trimming or due to the capital program and includes that he “believed many outages
13 categorized as other outages, such as wind and equipment, are actually caused by
14 vegetation contact”.⁵⁶

15

16 **Q64. Has the Company addressed tree-trimming impacts in the Reliability Model?**

17 A64. Yes, the Reliability Model baseline separates tree-related events from non-tree-
18 related events, and program effectiveness only applies to the specific types of
19 events the scope of work has measured effectiveness in improving. Namely, when
20 tree trimming is performed on a circuit, the model projects a reduction in tree-
21 related events, but non-tree related events are not impacted. Conversely, when a
22 reliability program such as PTMM is planned for a circuit, the non-tree related
23 events are reduced, but tree related events are not impacted. Addressing Witness
24 Alvarez’s concern that outages caused by wind are likely tree related and might not

⁵⁵ Stowe Revised DT, Page 27, lines 1-9

⁵⁶ Alvarez, page 31, lines 13-16, footnote 32

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1 see a large benefit from PTMM, the Company generally agrees. The baseline data
2 categorizes outage events with the 'wind' cause code as being tree related.
3 Therefore, the reliability programs do not project any reductions on wind-related
4 outages, and the benefits are not 'exaggerated' as he claims.
5

6 **Q65. What concerns does Witness Alvarez express regarding the baseline data in**
7 **the Reliability Model?**

8 A65. He has three concerns with the baseline data, the first is that it is based on Ex-MED
9 performance, the second is that it is "manipulated", and the third is that the
10 Company uses average customer interruptions and customer minutes interrupted
11 per event. Each of these concerns is either incorrect or unsupported.
12

13 **Q66. Why does the Company use Ex-MED performance for the baseline?**

14 A66. The Reliability Model is based on ex-MED performance as it is more consistent
15 year over year and provides a better indicator as to whether the system is improving,
16 because it minimizes the volatility and noise from severe weather events. During
17 the 5-year baseline of the model, 2018-2024, 84% of event volume and 75% of
18 SAIFI occurred during ex-MED days, therefore a majority of the system events and
19 customers impacted are captured by ex-MED days. Witness Alvarez must also
20 realize that ex-MED metrics are useful in comparing performance as Figure 1 in
21 his testimony utilizes ex-MED performance, as does the analysis of AG-MN
22 Witness Stephens which he references.⁵⁷
23

⁵⁷ Alvarez, page 31, lines 5-9

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1 **Q67. What issues does Witness Alvarez have with how the baseline data is processed**
2 **to create the model?**

3 A67. He testifies regarding the “data manipulation in which DTE engages” to create the
4 baseline, including expressing concern that outages are “separated” depending on
5 whether they are vegetation related or based on the number of customers impacted.

6 ⁵⁸

7 **Q68. Does the Company manipulate the data to create the model baseline?**

8 A68. Quite simply, yes, but not in an outcome driven way that it seems Witness Alvarez
9 suggests. Witness Alvarez does not define what he means by data manipulation,
10 but one definition provided by the technology company Lenovo is that “data
11 manipulation refers to the process of changing or transforming data in order to
12 extract valuable insights, perform calculations or prepare it for analysis and
13 presentation. This can involve various operations such as filtering, sorting,
14 aggregating, merging and transforming data”.⁵⁹ Considering the Reliability Model
15 is based on extracting insights from close to a million events across thousands of
16 distribution circuits, a level of filtering, sorting and aggregating data is necessary
17 to build a useful model. It is not clear what issue Witness Alvarez has from the
18 action of “separating outages caused by vegetation contact from other outage
19 causes, and separating out outages impacting just one customer from outages
20 impacting more than one customer”.⁶⁰ This action does not change the total number
21 of events attributed to the circuit baseline and is a reasonable and prudent step in
22 better understanding the facts and circumstances.

⁵⁸ Alvarez, page 30, line 3, lines 7-8

⁵⁹ [Data Manipulation: What it is, and How It Can Help Your Business | Lenovo US](https://www.lenovo.com/us/en/glossary/data-manipulation/),
<https://www.lenovo.com/us/en/glossary/data-manipulation/> accessed 9/5/2025

⁶⁰ Alvarez, page 30, lines 7-9

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1 Finally, Witness Alvarez objects to using average customers interrupted per event
2 or average customer minutes interrupted per event. The Reliability Model primarily
3 relies on 12 different outage event types, with combinations covering tree versus
4 non-tree, single versus multiple customers, and 4.8kV, 8.3kV or 13.2kV. There are
5 two main reasons to use average event size. First it simplifies what is already a
6 relatively complex model. Second, using average event impact avoids the problem
7 that may occur from projecting performance on circuits with a relatively small
8 number of outages in its historical baseline data. For example, if a circuit has a
9 relatively small number of events, the historical baseline outage size will be
10 significantly larger if those events were at the beginning of the circuit and caused
11 an outage on the entire circuit, and significantly smaller if the events occurred on a
12 lateral and only impacted a small number of customers. Future performance is more
13 likely to be closer to the average number of events and the average size of an outage
14 on a system of the same voltage type.

15

16 **Q69. What does Witness Alvarez claim regarding the method used to scale up ex-**
17 **MED performance to All-Weather performance?**

18 A69. He claims that the scaling method is not in line with the Company's historical
19 performance and, therefore, significantly exaggerates performance improvements.

20

21 **Q70. Why is Witness Alvarez's discussion of the scaling methodology incorrect?**

22 A70. First, he claims that the "model multiplies the projected system average interruption
23 duration by a scaling factor of between 1.40 and 3.42".⁶¹ While Witness Alvarez
24 references my revised direct testimony, the conclusions drawn are not correct

⁶¹ Alvarez, page 32, lines 15-16

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1 regarding how the scaling methodology works. My revised direct testimony
2 actually states: “If the model projects the Company’s SAIDI ex-MED performance
3 to be 100 minutes, it would also calculate a range of expected all-weather outcomes
4 to be 140 to 342 minutes”.⁶² However, this is an illustrative example. The Company
5 performance, especially historically, has not been 100 minutes ex-MED. The
6 scaling factors change based on the ex-MED value that is used as an input to
7 calculate all-weather values. The scaling factor is calculated based on the values in
8 the Reliability Model on the tab “AW Scale Up”. He also claims that the Company
9 excludes the top and bottom 20% of outcomes from the scale up. This is not
10 accurate either. The favorable and unfavorable bands are set at the top 20% and
11 bottom 20% of utility performance. In other words, the data from the performance
12 of the top and bottom 20% utility performance is what sets the upper and lower
13 bands of the model. Finally, he recommends that the scale up factor should be 5.23
14 simply by taking an “average” of historical scaling factors.⁶³ However, this
15 demonstrates a lack of understanding of the purpose of the methodology – namely
16 that there is a relationship between ex-MED and all-weather performance that is
17 not fixed but will change over time as ex-MED performance improves.

18
19 **Q71. How does the all-weather scaling methodology performance compare to the**
20 **Company actuals?**

21 A71. Figure 2 below shows how the all-weather scale up formulas work. For any given
22 ex-MED SAIDI on the x-axis, the chart shows the range for the favorable lower
23 bound and the unfavorable upper bound, as well as DTE Electric performance over
24 the last 10 years. The Company has been within the “middle 60%” range five times,

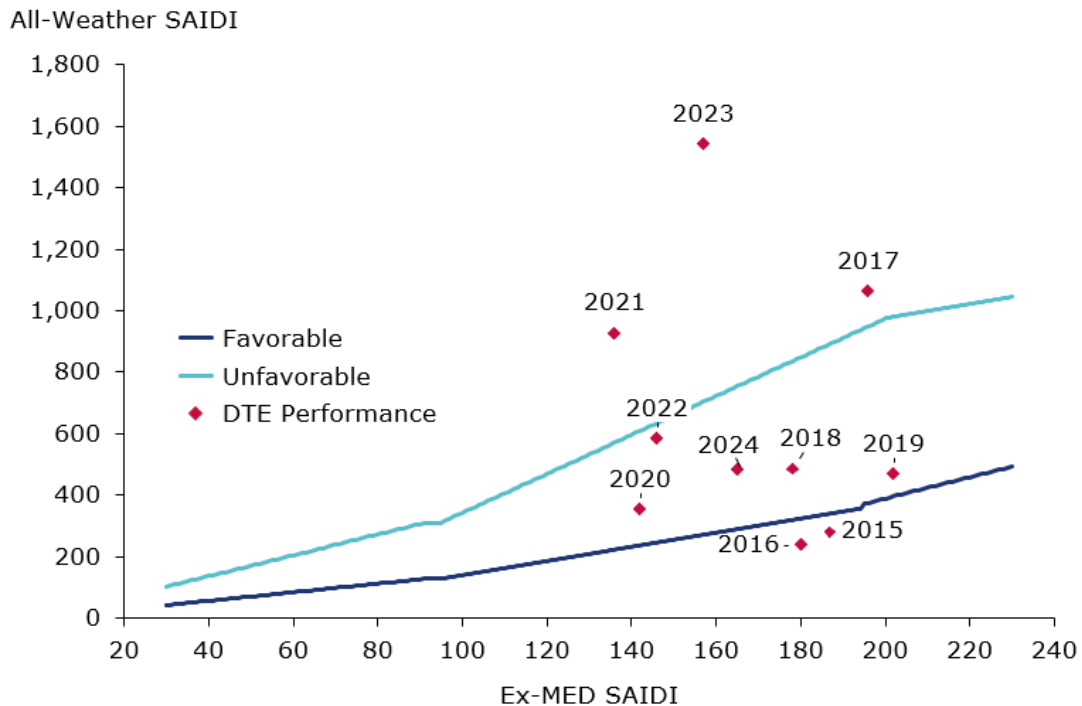
⁶² Kryscynski Revised DT, page 37, lines 13-15

⁶³ Alvarez, page 33, lines 4-6

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1 below the favorable bound twice, and above the unfavorable bound three times.
2 Considering the upper and lower bounds should occur approximately 20% of the
3 time, the Company's actual performance is very much in line with what would be
4 expected, indicating this method provides a very reasonable predictor of an all-
5 weather range given an ex-MED performance. Witness Alvarez's claim that this
6 methodology is not consistent with Company performance is incorrect.

8 **Figure 2 Reliability Model All-Weather Scale Up and DTE Performance**



10
11 **Q72. What does Witness Alvarez claim about the accuracy of projected**
12 **improvements of the Reliability Model?**

13 A72. He claims that the accuracy has not been tested against the projections.⁶⁴

⁶⁴ Alvarez, page 32, lines 8-9

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1 **Q73. Has the accuracy of the Reliability Model been tested against the projections?**

2 A73. Yes. First, he claims that the model predicts an improvement of the “baseline of
3 563 minutes in 2024”.⁶⁵ This is an inaccurate statement. The entire model baseline
4 is based on an average of 2018-2022 performance, which is how the 563 minute
5 starting point was derived. Second, Witness Alvarez disregards facts provided in
6 my revised direct testimony that the Reliability Model projected 2024 performance
7 of 504 minutes of All-weather SAIDI and 1.30 SAIFI, and actual performance was
8 483 minutes and 1.25 SAIFI.⁶⁶ The results of this empirical testing show that the
9 model has been conservative (underestimated) in its reliability improvement
10 projections by 4% for SAIDI and SAIFI.

11

12 **Q74. How accurate is the 2025 performance projected to be?**

13 A74. Based on performance through the end of August, the forecasted all-weather SAIDI
14 is 260 minutes and the forecasted SAIDI ex-MED is 150 minutes. The Reliability
15 Model projects 448 minutes of all-weather SAIDI and a lower band of 262,
16 indicating that current projections are at the “favorable” weather band. The
17 Reliability Model also projects a 152 SAIDI Ex-MED, with the current forecast
18 being 1% better than the model projection. For the past two years, the Reliability
19 Model has been accurate and has forecasted results that are more conservative than
20 actual system performance in 2024 and 2025.

21

22 **Q75. Does the Company plan to continue to evaluate and improve the Reliability**
23 **Model over time?**

⁶⁵ Alvarez, page 28, line 21

⁶⁶ Kryscynski Revised DT, page 40, lines 3-5

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1 A75. Yes. The Company improved the model since the last case by updating the
2 effectiveness assumptions methodology and utilizing annual data (the previous
3 iteration utilized 10-month periods). The Company also updated the effectiveness
4 analysis with actual reliability performance from 2024. The Company will continue
5 to measure reliability benefits of the modeled programs and update expected
6 benefits as additional data and analysis is available. The Company may also add
7 additional investment categories to the model, update the degradation analysis, or
8 add a factor to account for more severe weather. Lastly, if the data and modeling
9 indicate that a program is not performing as expected, the Company will also
10 reevaluate that program for future investment.

11

12 **Q76. What does Witness Alvarez recommend regarding reliability performance**
13 **and cost recovery?**

14 A76. He recommends that the Commission “implement mechanisms that place DTE cost
15 recovery at risk when the improvements DTE projected fail to materialize.”⁶⁷

16

17 **Q77. Does the Company agree with this recommendation?**

18 A77. No. The proposal is neither reasonable nor appropriately addressed in this
19 proceeding. Witness Alvarez’s proposal does not seek to accurately estimate the
20 correct investments and prospectively establish the correct rates but appears
21 intended only to penalize the Company for past actions and projections it might
22 someday argue were incorrect. The Company has a pending proposal in Case No.
23 U-21909 regarding financial incentives and disincentives for reliability
24 performance that includes seven key metrics and targets consistent with the

⁶⁷ Alvarez, page 34, lines 5-6

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1 Commission's Service Quality and Reliability Standards. The targets for the two
2 SAIDI metrics in the proposal require year-over-year performance improvements.
3 This proposal is the result of more than two years of discussion among the
4 Company, Commission Staff, and stakeholders (including the organizations
5 Witness Alvarez represents in this case) in Case No. U-21400. As such, the
6 Commission should reject this recommendation as it concerns both rate case
7 investments and IRM investments.

8 **Rebuttal Issue 4: Environmental Justice (EJ)**

9 **Q78. What recommendations have been made by Witnesses regarding the**
10 **Company's Environmental Justice (EJ) analysis?**

11 A78. Several Witnesses requested that the Company do more tracking and reporting of
12 EJ-related metrics, as well as more granular, detailed EJ analysis. Specifically:

- 13 • DAAO Witness Nichols claims states that MiEJ Screen "fails to provide a
14 sufficiently comprehensive picture of the needs and challenges specific to
15 individual neighborhoods, households, or customer sub-groups within a
16 given census tract."⁶⁸
- 17 • DAAO Witness Nichols requests that "DTE immediately conduct an
18 analysis comparing service reliability in vulnerable census tracts to non-
19 vulnerable census tracts with similar population densities and other
20 characteristics (e.g. urban EJ to urban non-EJ) and develop a comprehensive
21 investment plan to eliminate any service disparities that analysis
22 identifies."⁶⁹

⁶⁸ Nichols Revised DT, page 21, lines 6-8

⁶⁹ Nichols Revised DT, page 28-29, lines 20-2

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- 1 • DAAO Witness Nichols requests that “DTE immediately conduct and
- 2 incorporate into its equity considerations an analysis of the extent to which
- 3 projects in vulnerable census tracts are benefitting residential versus
- 4 commercial customers.”⁷⁰
- 5 • DAAO Witness Nichols requests “DTE to perform an analysis before its
- 6 next general rate case to determine whether its EJ multiplier is actually
- 7 resulting in increased selection for funding of projects benefiting vulnerable
- 8 communities and, if yes, by how much, and if no, why not.”⁷¹
- 9 • CEO Witness Tan requested that “the Commission order the Company to
- 10 run regression analysis for every rate case, as well as DTE’s Distribution
- 11 Grid Plans.”⁷²
- 12 • CEO Witness Kenworthy states “I recommend that reliability reporting
- 13 include distributions—not just averages—across EJ gradations, and that
- 14 investment decisions pair MiEJScreen with reliability and energy-burden
- 15 indicators so dollars close persistent service gaps without worsening
- 16 affordability.”⁷³

17

18 **Q79. How does the Company respond to these Witnesses’ recommendations and**

19 **requests?**

20 A79. The Company has reviewed the concerns and recommendations of each witness

21 noted above. While each witness offers a distinct point regarding their opinion on

22 potential improvements to the MiEJ screening tool and the Company’s analysis,

23 none of their comments raise compelling concerns about the validity of the

⁷⁰ Nichols Revised DT, page 29, lines 3-5

⁷¹ Nichols Revised DT, page 29, lines 6-9

⁷² Tan, page 21, lines 5-6

⁷³ Kenworthy, page 27, line 14-17

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1 Company's EJ analysis which a key component of the Company's GPM analysis
2 comparing investments in the instant case. The Company therefore does not believe
3 that additional EJ analysis beyond what has already been ordered by the
4 Commission is appropriate in the instant case. Please refer to my revised direct
5 testimony in Part II and Part V which describes how EJ is currently considered
6 when proposing long-term investments. The Company plans to continue to rely on
7 the MiEJScreen Tool for the basis for prioritization and analysis regarding EJ
8 Communities. The Company believes this is the appropriate tool to use for
9 distribution analysis, because it was developed with extensive input from Michigan
10 stakeholders, including experts in the EJ community, is maintained by the State of
11 Michigan, and includes a breadth of socioeconomic and environmental factors in
12 its EJ impact scoring that the Company does not maintain and does not have the
13 expertise to compile.⁷⁴ The Company recognizes that EJ data, tools, and analysis
14 will continue to evolve. The Company will continue to analyze the most current
15 data and tools available and looks forward to continuing to collaborate with
16 stakeholders to gather their input on the future analysis and development of plans
17 for the 2026 Distribution System Plan.

18

19 **Q80. What steps has the Company taken to ensure its prioritization of EJ**
20 **communities?**

21 A80. The Company has developed a thoughtful and comprehensive methodology for
22 prioritizing EJ communities using the MiEJScreen Tool. This approach
23 appropriately aligns the geographic scale of distribution and subtransmission
24 projects with EJ populations, as defined by census tracts. More granular

⁷⁴ Kryscynski Revised DT, page 44, Figure 3

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1 breakdowns, such as individual streets or neighborhoods, are not particularly
2 useful, as grid solutions are typically planned and implemented at the circuit or
3 substation level.

4

5 **Q81. Did the Company file the DAAO requested analysis ordered by the**
6 **Commission?**

7 A81. The Company will collaborate with Staff and interested stakeholders to understand
8 the proposed methodology and plans to include this analysis in the 2026 DSP. This
9 includes how to “evaluate changing demographics over time using data consistent
10 with the underlying data sets for the detailed regression analysis already required
11 to investigate ‘customer demographics and reliability for vulnerable communities
12 to be used in the company’s distribution plan case’ to help enable a complete
13 understanding of equity outcomes, including along the lines of race and class.”⁷⁵.
14 This is a complex analysis with numerous variables and data limitations that will
15 require stakeholder engagement to understand. The expectation for the Company
16 to complete this type of analysis with the appropriate level of rigor and engagement
17 within the three-month timeframe before this case was filed ⁷⁶ posed challenges.

18

19 **Q82. What is the Company’s proposed next step regarding the EJ regression**
20 **analysis discussed in Case U-21534?**

21 A82. The Company is actively collaborating with Staff and the CEO on the EJ regression
22 analysis, which will be included in the 2026 DSP. This joint effort aims to develop
23 a robust approach that stakeholders, including the Company, can support.

⁷⁵ Nichols Revised DT, page 24-25, lines 18-1

⁷⁶ Nichols Revised DT, page 25, lines 9-12

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1 **Q83. What does DAAO Witness Watts claim about the Company's investment with**
2 **regard to low-income neighborhoods?**

3 A83. Witness Watts claims that "DTE invests less in lower-income neighborhoods, even
4 though lower-income neighborhoods have less reliable power lines and more
5 outages."⁷⁷ She then goes on to state that "lower-income communities do not feel
6 meaningful changes or benefits" from investments.⁷⁸

7
8 **Q84. Does Witness Watts provide any evidence to substantiate his opinion?**

9 A84. No. She cites a 2022 Guardian article that is rife with inaccuracies and does not
10 provide any evidence that the Company invests less in lower-income
11 neighborhoods nor does it provide any evidence that lower-income communities do
12 not see meaningful changes or benefits.

13
14 **Q85. Has the Company shown that vulnerable EJ communities are seeing increased**
15 **investment and positive reliability outcomes?**

16 A85. Yes. Section V of my revised direct testimony details the substantial investment the
17 Company is making in vulnerable communities as well as the positive reliability
18 outcomes relative to less-vulnerable communities.⁷⁹

19
20 **Q86. Does the Company provide evidence that vulnerable EJ communities have**
21 **equal or better than average reliability?**

22 A86. Yes. As mentioned in my revised direct testimony reliability data confirms that
23 vulnerable communities, those in the top 80th percentile and above of MiEJScreen

⁷⁷ Watts, page 31, lines 12-14

⁷⁸ Watts, page 31, lines 17-19

⁷⁹ Kryscynski Revised DT, begins on page 41, line 14

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scores consistently experience equal or better reliability than the system average for both SAIFI and SAIDI in both All-Weather and Non-MED.⁸⁰ As an example, from my revised direct testimony, shown here as Table 5, below shows that from 2020 to 2024, vulnerable communities had lower SAIFI values, meaning fewer interruptions. This is clearly demonstrated in the table below.

Table 5 All Weather SAIFI Reliability Performance of Census Tracts

Census Tract EJ % Group	Category	2020 SAIFI	2021 SAIFI	2022 SAIFI	2023 SAIFI	2024 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

8

9 **Q87. Does this conclude your rebuttal testimony?**

10 **A87.** Yes, it does.

⁸⁰ Kryscynski Revised DT, page 55, lines 11-13

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

REBUTTAL TESTIMONY

OF

JOSEPH E. ROBINSON

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF JOSEPH E. ROBINSON

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6	Rebuttal Issue 2: AG-MN Witness Stephens’s recommendation to order a 10-year pole	
7	top inspection cycle.....	4
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9	year pole-top inspection cycle lacks a supporting cost-benefit analysis.....	7
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11	policies	8
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15	overstated and thus asserts the Company should maintain current investment levels..	10
16	Rebuttal Issue 7: CEO Witness Volkmann’s request for sensitivity analysis on PTMM	
17	cost estimates.	12
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27	Rebuttal Issue 11: AG-MN Witness Coppola inaccurate claims regarding insufficient	
28	evidence for incremental O&M investments for preventative and corrective	
29	maintenance activities.....	22

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF JOSEPH E. ROBINSON

Line
No.

1 **Q1. Please state your full name, business address and by whom you are employed?**

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

5

6 **Q2. Did you file revised direct testimony in this proceeding on behalf of DTE**
7 **Electric Company?**

8 A2. Yes.

9

10 **Purpose of Testimony**

11 **Q3. What is the purpose of your rebuttal testimony?**

12 A3. The purpose of this testimony is to rebut certain positions of Witnesses Alvarez and
13 Stephens on behalf of the Attorney General (AG), Michigan Environmental
14 Council (MEC), and Natural Resources Defense Council (NRDC), collectively
15 referred to as “AG-MN,” Witness Coppola on behalf of the Attorney General (AG),
16 Witness Volkmann on behalf of Environmental Law & Policy Center, The Ecology
17 Center, Union of Concerned Scientists, and Vote Solar, collectively referred to as
18 “CEO,” Witness Fitzhenry on behalf of Association of Businesses Advocating
19 Tariff Equity (ABATE), and Witness Stults on behalf of the City of Ann Arbor
20 (AA). The absence of a discussion of other matters in my rebuttal testimony should
21 not be taken as an indication of agreement with other aspects of any intervenor’s
22 testimony.

23

24 **Q4. Are you sponsoring any exhibits in this proceeding?**

25 A4. Yes. I am sponsoring the following exhibits:

Line
No.

Line No.	Exhibit	Schedule	Description
1			
2	A-51	RR1	Discovery Response: U-21860 CEODE-1.2
3			

4 **Q5. Were these exhibits prepared by you or under your direction?**

5 A5. Yes, they were.

6

7 **Q6. How is your testimony organized?**

8 A6. My testimony is organized around several key themes that emerged across the
9 witnesses representing various stakeholder groups. For each topic listed in the
10 Table of Contents, I will provide a detailed discussion that addresses specific
11 inaccuracies and/or erroneous assumptions presented in their testimony. I will also
12 explain why certain recommendations made by these witnesses should not be
13 adopted by the Commission.

14

15 **Pole and Pole Top Maintenance and Modernization Program (PTMM)**

16 Rebuttal Issue 1: AG-MN Witness Stephens's statements regarding the condition of DTEE
17 pole and pole tops

18 **Q7. What does AG-MN Witness Stephens say regarding the condition of DTEE's**
19 **poles and pole tops?**

20 A7. AG-MN Witness Stephens says, "[t]here are other indications that DTE poles and
21 poletops are not in unreasonably poor condition. For example, the Auditor¹ found
22 that of 120 poles inspected, just six had condition issues that DTE had not already
23 identified, a defect rate of just 5%."²

¹ The Auditor that Witness Stephens is citing is Liberty Consulting (hereinafter "Liberty" or the "Auditor"). Specifically Witness Stephens is referencing the document titled, Final Report, Utility Distribution Audit of DTE Energy, Part One, pgs. 38-47.

² Witness Stephens's Direct Testimony, p. 46, ll. 15-20

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1 **Q8. How do you respond to Witness Stephens’s assertion that the Auditor**
2 **identified only six poles with condition issues, representing a defect rate of just**
3 **5%?**

4 A8. I disagree. The Audit report indicates that the Auditor identified eight poles with
5 condition issues and two with safety issues³—bringing the total to ten poles, not
6 six. This equates to a defect rate of 8.3%, not the 5% claimed by Witness Stephens.

7

8 Furthermore, extrapolating this 8.3% defect rate across DTE Electric’s system of
9 1.1 million poles suggests that approximately 92,000 poles require replacement or
10 other work. This figure does not include additional poles identified through ground-
11 line pole testing, which revealed a separate defect rate of 3%, or approximately
12 33,000 poles. Combined, these findings result in a total estimated defect rate of
13 11.3%, representing approximately 125,000 poles that require replacement. This is
14 more than twice the amount of indicated repair work that Witness Stephens
15 incorrectly identifies. These findings directly refute the notion that DTE Electric’s
16 poles and pole tops are in such good condition that they do not require meaningful
17 amounts of increased and continuing maintenance and modernization.

18

19 Rebuttal Issue 2: AG-MN Witness Stephens’s recommendation to order a 10-year pole top
20 inspection cycle

21 **Q9. What does AG-MN Witness Stephens say in his recommendation to order a**
22 **10-year inspection cycle?**

23 A9. AG-MN Witness Stephens recommends that the Commission, “Order the visual
24 poletop inspection frequency requirement be relaxed from once every five years to

³ Audit Report, Part One, Chapter 4, p. 37

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1 once every ten years (in recognition of the fact that the reliability improvement
2 opportunity is simply not that significant).”⁴

3

4 **Q10. Does the Audit support Witness Stephens’s recommendation?**

5 A10. No. Witness Stephens’s recommendation is in direct conflict with both the Audit
6 report’s conclusions and Liberty’s recommendations regarding PTMM inspection
7 cycles.

8

9 First, Witness Stephens’s suggestion regarding the frequency of poletop inspections
10 appears to disregard the Audit’s conclusion, which states: “Distribution equipment
11 failure has remained a major cause of outages for DTE. As we believe DTE
12 acknowledges, the Company needs to gain first the visual control over its system
13 that more frequent inspections will bring, followed by the physical control that will
14 come by repairing and replacing broken or deteriorated poles and pole-top
15 equipment that pose immediate threats.”⁵

16

17 Second, Witness Stephens’s suggestion contradicts the Audit’s specific
18 recommendation to adopt a four-to-five year visual overhead circuit inspection
19 program. The supporting commentary in the Audit reinforces this position, stating:
20 “Both the current PTMM cycle and the proposed 10-year one are too long to allow
21 the identification and remediation of immediate equipment failure threats.”⁶

22 In conclusion, Witness Stephens’s recommendation to extend the visual pole-top
23 inspection cycle to ten years is not supported by the analysis or conclusions of the

⁴Witness Stephens’s Direct Testimony, p. 58, ll. 17-19

⁵ Audit Report, Part Two, Chapter 1, p. 40

⁶ Audit Report, Part Two, Chapter 1, p. 43

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1 Audit nor any analysis presented by Witness Stephens. “In my experience the same
2 cycle for poletops as for poles is more common, and a benchmarking exercise is
3 insufficient support for a five-year poletop inspection cycle.”⁷ Witness Stephens
4 did not provide more than his generalized experience elsewhere in recommending
5 a ten-year cycle for DTE Electric’s distribution system. The recommendation
6 directly contradicts both the findings and guidance presented in the Audit report,
7 which emphasizes the critical need for more frequent inspections to identify and
8 address equipment failures that pose immediate reliability risks. Maintaining a five-
9 year pole-top inspection cycle is essential to improving and maintaining
10 distribution system integrity and reducing outage events for customers.

11

12 **Q11. What does the Company’s benchmarking say in relation to Witness Stephens’s**
13 **recommendation?**

14 A11. The Company’s benchmarking also refutes Witness Stephens’ proposal to relax
15 inspection cycles. Table 4 on page 24 of my revised direct testimony provides the
16 Pole Inspection and Pole-Top Inspection cycle identified in seven utilities located
17 in the Northeast and Midwest, indicating that most utilities operate on a 10-year (or
18 less) cycle time for pole inspections and maintenance, and a 5-year cycle time for
19 pole-top inspections and maintenance. Five of the seven utilities have a 5-year (or
20 less) cycle. Witness Stephens’s recommendation for a 10-year pole-top cycle does
21 not align with this benchmarking.

22

23 **Q12. Does the Commission’s guidance on an appropriate cycle for PTMM in Case**
24 **No. U-21534 align with Witness Stephens’s recommendation?**

⁷ Witness Stephens’s Direct Testimony, p. 48, ll.10-12

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1 A12. No. Witness Stephens's recommendation is in direct conflict with the guidance the
2 Commission provided in its January 23, 2025 Order in Case No. U-21534. In that
3 case, roughly seven months ago, the Commission stated that "[i]n the company's
4 next rate case, [it] expects to see progress in DTE Electric's goal of reaching the 5-
5 year and 10-year cycles 'utilizing the reliability tier model and BCA output, to
6 select the optimal mix of circuits to improve customer reliability' to match the
7 industry standards that the company has identified through its benchmarking
8 efforts."⁸

9

10 **Q13. Should the Commission adopt AG-MN Witness Stephens's recommendation**
11 **to order a 10-year inspection cycle?**

12 A13. No. The Commission should reject AG-MN Witness Stephens's recommendation
13 to order the Company to adopt a 10-year inspection cycle for pole top equipment.

14

15 Rebuttal Issue 3: AG-MN Witness Stephens's claim that DTE Electric's shift to a 5-year
16 pole-top inspection cycle lacks a supporting cost-benefit analysis

17 **Q14. What does AG-MN Witness Stephen claim regarding DTEE's plan for a 5-**
18 **year pole-top inspection cycle?**

19 A14. Witness Stephens says, "[a] change in inspection practices, and particularly one
20 DTE expects will cost \$1.3 billion to implement 2026 to 2029, should be supported
21 by an analysis that compares the incremental costs of a proposed change in practice
22 to the incremental benefits of the proposed change. DTE appears to have completed
23 no such analysis before reaching a decision to switch to a five-year poletop
24 inspection cycle."⁹

⁸ Case No. U-21534 - Order dated January 23, 2025, p. 108

⁹ Witness Stephens's Direct Testimony, p. 48, ll. 12-16

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1 **Q15. Do you agree with AG-MN Witness Stephens’s assertion that the Company**
2 **should have conducted a cost-benefit analysis before adopting a 5-year pole-**
3 **top inspection cycle?**

4 A15. No. The Company’s decision to adopt a 5-year pole-top inspection cycle was based
5 on four key factors: (1) an appropriate benefit-cost analysis, the conclusion of
6 which determined that there was a \$1.96 billion customer benefit from the 5-year
7 pole-top inspection cycle and \$2.81 billion customer benefits from the 10-year
8 groundline pole cycle; (2) the Audit recommendation supporting the 5-year cycle;
9 (3) industry benchmarking aligned with this approach; and (4) Commission
10 guidance provided in its January 23, 2025 Order in Case No. U-21534 encouraging
11 progress toward a 5-year cycle. These factors demonstrate that the Company’s
12 decision was informed and aligned with regulatory guidance, industry
13 benchmarking, and an appropriate benefit-cost analysis.

14

15 Rebuttal Issue 4: AG-MN Witness Stephens’s concerns about PTMM capitalization
16 policies

17 **Q16. What does Witness Stephens assert concerning the Company’s PTMM**
18 **capitalization policies?**

19 A16. Witness Stephens asserts generally, “DTE is capitalizing some or all of these costs
20 as part of the PTMM program”¹⁰ and goes on to offer opinions concerning the
21 Uniform System of Accounts and how he believes it should be applied.

22 **Q17. How do you respond with respect to Witness Stephens’s comments?**

23 A17. I am not an accountant and don’t propose to offer a technical accounting opinion.
24 The Company follows the capitalization policy as described in CEODE-1.2

¹⁰ Witness Stephens’s Direct Testimony, p. 51, ll. 2-3

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1 provided in Exhibit A-51, Schedule RR1 which the Company believes is
2 appropriate. Company Witness Uzenski's Rebuttal Testimony provides additional
3 details under the header "Pole & Pole Top Maintenance and Modernization
4 (PTMM) Program Capitalization".

5

6 Rebuttal Issue 5: ABATE Witness Fitzhenry assertion that DTEE lacks data to estimate
7 the costs of the PTMM program

8 **Q18. What does ABATE Witness Fitzhenry say in his recommendation regarding**
9 **the Company's proposed PTMM investment?**

10 A18. ABATE Witness Fitzhenry states, "The Audit also notes that DTE lacks reliable
11 data to accurately estimate the costs for its proposed PTMM program. I recommend
12 the Commission reduce PTMM investments for the 2026-2029 period to 2025
13 levels, adjusted for inflation."¹¹

14

15 **Q19. Do you agree with Witness Fitzhenry's claim that DTE Electric does not have**
16 **sufficient data to accurately estimate the costs of its proposed PTMM**
17 **program?**

18 A19. No. Witness Fitzhenry's assertion does not reflect the current state of available data.
19 The models presented in this case—specifically the Benefit Cost Analysis (BCA)
20 for PTMM supported by Company Witness De Stigter, and the PTMM ramp-up
21 plan—were developed after the Audit was completed, directly in response to its
22 recommendations. These models provide the necessary framework, using detailed
23 cost information and providing calculated customer benefits, to support the
24 appropriate future investment levels for the PTMM program.

¹¹ Witness Fitzhenry's Direct Testimony, p. 3, ll. 13-15

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1 I explain from page 29, line 17 to page 30, line 2 of my revised direct testimony:
2 “As shown in Figure 8 below, the Company developed a ramp-up plan to meet the
3 PTMM 5-year and 10-year audit recommended cycles. Using system-wide
4 averages based on the PTMM BCA, the Company anticipates reaching audit
5 recommended cycles by 2029. The overall annual investment level is anticipated to
6 decrease as circuits begin the second and subsequent cycles. Investment will
7 continue to decrease until all circuits are on a 5-year pole-top cycle. This aligns
8 with the Audit Report that states, '[i]t also needs to be recognized that work, and
9 therefore costs per year on a four-year cycle, will be higher. However, once having
10 addressed the entire system, this cycle will lead to much reduced costs for the
11 following years. Over time, a shorter cycle will not produce greater work. However,
12 it will remove damaged and deteriorated poles and equipment more timely from the
13 system and reduce restoration costs.’¹²”
14 These developments demonstrate that the Company has and is utilizing the tools
15 and data necessary to make informed cost estimates for the PTMM program moving
16 forward.

17

18 Rebuttal Issue 6: ABATE Witness Fitzhenry contends that PTMM benefits are overstated
19 and thus asserts the Company should maintain current investment levels

20 **Q20. What does ABATE Witness Fitzhenry say concerning PTMM benefits?**

21 A20. ABATE Witness Fitzhenry says, "the reliability benefits derived from the
22 Company's BCA overstate the benefits of reliability improvements with respect to
23 the PTMM program."¹³

¹² Audit Report, Part Two, Chapter 1, p. 43

¹³ Witness Fitzhenry's Direct Testimony, p. 14, ll. 7-8

Line
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1 **Q21. How do you respond to Witness Fitzhenry's assertion that PTMM benefits are**
2 **overstated?**

3 A21. I disagree. As demonstrated by Company Witness De Stigter's comprehensive
4 evaluation of both groundline pole and pole-top components across DTE Electric's
5 overhead distribution system, the BCA accurately reflects the reliability
6 improvements and customer benefits associated with the PTMM program. Efforts
7 to improve efficiency are ongoing, but maintaining current investment levels would
8 risk undermining the long-term value and system reliability the program is designed
9 to deliver.

10

11 **Q22. What does ABATE Witness Fitzhenry say regarding the PTMM program and**
12 **investment levels?**

13 A22. Witness Fitzhenry says, "The Company should consider how to improve
14 efficiencies in its current program, so that the number of miles of pole and pole-top
15 inspections can be increased without increasing current costs, which have already
16 been elevated above historical expenditure levels."¹⁴

17

18 **Q23. Do you agree with ABATE Witness Fitzhenry's assertion that program**
19 **efficiencies can be improved without any increase in current investment**
20 **levels?**

21 A23. No. I respectfully disagree with the assertion that efficiencies could be improved
22 without increasing current costs, as it fails to recognize the scale and complexity of
23 the expanded PTMM work scope planned for 2025 and 2026. The expectation that
24 inspection and replacement volumes can increase without additional investment

¹⁴ Witness Fitzhenry's Direct Testimony, p. 14, ll. 9-12

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1 overlooks the reliability-driven nature of this program. As stated in my revised
2 direct testimony, pages 32-33, in 2025, the Company is investing \$121 million to
3 execute a work plan that includes replacing poles and pole-top equipment across
4 approximately 1,340 circuit miles—resulting in roughly 6,150 pole replacements
5 and 6,360 pole-top equipment replacements at locations that failed inspection. For
6 2026, the Company is requesting \$200 million to support replacements across
7 approximately 2,000 circuit miles, including an estimated 9,090 poles and 10,720
8 pole-top equipment locations. These investments are critical to achieving the
9 reliability improvements and customer value substantiated by the Company’s
10 benefit-cost analysis and cannot be realized by maintaining historical investment
11 levels.

12

13 Rebuttal Issue 7: CEO Witness Volkmann’s request for sensitivity analysis on PTMM cost
14 estimates.

15 **Q24. What specific recommendation did CEO Witness Volkmann make regarding**
16 **the PTMM program and its associated cost assumptions?**

17 A24. Witness Volkmann recommended that DTE Electric include a sensitivity analysis
18 in its rebuttal testimony to evaluate the potential impact of escalating material and
19 labor costs. Specifically, he stated, “I recommend that DTE, in its rebuttal
20 testimony, include a sensitivity analysis on the impact of potential increases to
21 wood pole, pole-top component, and labor costs. For example, DTE’s sensitivity
22 analysis could provide answers to questions such as:

- 23 • What is the total amount of investment required to achieve the desired 5- and
24 10-year PTMM cycles, and which circuits have PTMM benefits in excess of
25 costs if, over the next four years:

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- 1 ○ Wood pole costs increase by 25% or 100%?
- 2 ○ Overhead transformer costs increase by 25% or 100%?
- 3 ○ PTMM labor costs increase by 10% or 30%?”¹⁵
- 4

5 **Q25. How does the Company view the recommendation to perform a sensitivity**
6 **analysis on potential increases in material and labor costs?**

7 A25. The Company appreciates CEO Witness Volkmann’s thoughtful recommendation
8 to include a sensitivity analysis addressing potential escalations in material and
9 labor costs—specifically for wood poles, pole-top components, overhead
10 transformers, and PTMM labor. Please see Witness De Stigter’s Rebuttal
11 Testimony for the Company’s analysis regarding this issue.

12
13 Rebuttal Issue 8: AA Witness Stults claims DTE Electric’s failure to follow a 4- to 5-year
14 pole inspection program caused \$2.6 million in avoidable costs.

15 **Q26. What does Witness Stults say in her recommendation for disallowing \$2.6**
16 **million in material costs?**

17 A26. Witness Stulz says, "this is the amount DTE would have saved (in material costs
18 alone) had it replaced the 18,090 poles for which it is requesting funding in the test
19 year at 2019 costs. This recommended disallowance prevents some of the increased
20 costs due to DTE’s failure to replace poles on a more prudent schedule from being
21 passed on to ratepayers. Even this disallowance would still leave ratepayers
22 shouldering additional costs that were avoidable had DTE performed normal
23 maintenance, notably including labor costs. Essentially, this allows the Company

¹⁵ Witness Volkmann’s Direct Testimony, p. 17, ll. 11-19

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1 to recover the full amount of the poles at the 2019 costs, but not at current day
2 costs."¹⁶

3

4 **Q27. Is Witness Stults's claim that DTEE could have avoided \$2.6 million in**
5 **material costs by following a 4- to 5-year pole inspection cycle accurate?**

6 A27. No. The claim is not accurate. The \$2.6 million estimate is speculative, does not
7 appear to consider the cost of money, and is based on hypothetical assumptions that
8 do not reflect actual inspection results or operational realities. It presumes that all
9 18,090 poles currently slated for replacement would have been identified and
10 replaced in 2019, which is unrealistic. It also assumes the Company could have
11 immediately scaled its PTMM resources from inspecting and maintaining
12 approximately 1,000 circuit miles in 2019 to approximately 6,700 circuit miles
13 annually—an impractical and unsupported expectation. Disallowing costs based on
14 such hindsight-driven scenarios disregards the complexities of prudent utility
15 planning and execution. Furthermore, the AA proposal does not seek to accurately
16 estimate the correct cost and rates associated with replacing poles and other
17 equipment identified as needing replacement in 2025 and 2026 – it is only intended
18 to penalize the Company for what AA believes should have occurred in the past.

19 **Q28. Should the Commission adopt AA Witness Stults's recommendation to**
20 **disallow \$2.6 million of PTMM material costs?**

21 A28. No. Based on the reasoning outlined above, the Commission should reject AA
22 Witness Stults's recommendation to disallow \$2.6 million of PTMM material costs.

23

¹⁶ Witness Stults' Direct Testimony, p. 21, ll. 3-10

Line
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1 **Major Event Risk – Substation Risk Projects**

2 Rebuttal Issue 9: AG-MN Witness Coppola’s statements on Substation Risk investment
3 showing no improvement trend.

4 **Q29. What are AG-MN Witness Coppola’s recommendations regarding Substation**
5 **Risk projects?**

6 A29. Witness Coppola generally recommends disallowances of the 2025 and 2026
7 forecasted capital expenditures associated with the Substation Risk projects
8 represented in lines 19 to 29 of page 10 in Exhibit A-12, Schedule B5.4.¹⁷
9 Subsequently, he cited the Apache, Chestnut, Drexel, Hood, and McGraw projects
10 for disallowance.¹⁸ These projects align to the total amount proposed for
11 disallowance, which is \$27,104,000 for 2025 and \$5,625,000 for 2026.¹⁹⁻²⁰ The
12 following rebuttal will focus on the cited projects.

13

14 **Q30. What are the reasons Witness Coppola cites for disallowance of the Substation**
15 **Risk project costs?**

16 A30. Witness Coppola’s disallowance recommendation is based on two related claims:
17 (1) “the Company has not adequately justified that the capital spending will result
18 in a significant improvement in reducing power outages and service reliability;”²¹
19 and (2) “the Company cannot quantify the improvement expected in the reliability
20 indices or that the capital investment will provide a net financial benefit to
21 customers.”²²

¹⁷ Witness Coppola’s Direct Testimony, p. 38, ll. 10-11

¹⁸ Witness Coppola’s Direct Testimony, p. 38, ll. 12-13; U-21860, Exhibit A-12, p. 10, l. 20 (Apache), l. 22 (Chestnut), l. 23 (Drexel), l. 24 (Hood), l. 25 (McGraw)

¹⁹ Witness Coppola’s Direct Testimony, p. 40, ll. 4-5

²⁰ U-21860, Exhibit AG-20, p.1, l. 9, column (c) and (d)

²¹ Witness Coppola’s Direct Testimony, p. 39-40, ll. 18-19;1

²² Witness Coppola’s Direct Testimony, p. 40, ll. 1-3

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1 **Q31. What is the Company's response to Witness Coppola's arguments?**

2 A31. Witness Coppola's two related reasons for disallowance disregard how the
3 Company supports its investment in Substation Risk projects. Specifically, the
4 Company presented testimony and related detailed project summaries supporting
5 Substation Risk projects, which explained these projects are aimed at repairing
6 existing substation failures or preventing future catastrophic failures. While
7 infrequent, substation failures can cause service interruptions for all customers
8 supplied by the affected substation. The nature of the event can result in electrical
9 explosions as well as fire, and the resulting equipment damage can take days,
10 weeks, months, or even years to repair. The specific investments in question are
11 necessary to provide service for approximately 32,500 customers and are not aimed
12 at reliability improvement projects that address outages from weather, trees and
13 overhead equipment failures.²³ As these projects remain under construction, any
14 attempt to evaluate the associated equipment based on historical reliability data is
15 premature and methodologically unsound. Accordingly, assertions suggesting a
16 lack of "significant improvement in reducing power outages and service reliability"
17 are either inaccurate or reflect a fundamental misunderstanding of their current
18 status and intended outcomes.

19

20 **Q32. What evidence did Witness Coppola present to support his disallowance**
21 **recommendation?**

22 A32. Witness Coppola states "[i]n discovery, the Attorney General asked the Company
23 to provide the number of failures and customers impacted by the substation

²³ Witness Robinson's Revised Direct Testimony, p. 85 (McGraw – 6,000 customers), p. 94 (Apache – 11,000 customers), p. 96 (Chestnut – 6,000 customers), p. 103 (Drexel – 7,500 customers), and p. 105 (Hood – 2,000 customers)

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1 problems during the six years from 2019 to 2024.”²⁴ The discovery questions did
2 not ask about failures and customers impacted by *substation problems*, however.
3 The discovery question requested, “for each project provide... the number of
4 failures and customers impacted each year 2019-2024.” Since my revised direct
5 testimony described both the originating events (*i.e.*, failures leading to the work)
6 and affected customers,²⁵ the question was interpreted to cover all failures (*e.g.*,
7 outages) and customer impacts related to circuits originally fed by project
8 substations.

9
10 Witness Coppola further remarked, “[t]he Attorney General also asked that the
11 Company provide information on the expected reduction in substation reliability
12 measured through the SAIDI, SAIFI, and CAIDI indices and the cost/benefit
13 analysis showing that the capital investments would provide a net economic benefit
14 to customers.”²⁶ This statement underscores that Witness Coppola misunderstood
15 the program’s true purpose, even though, as clarified in discovery, “[t]hese projects
16 are created to rebuild substations after catastrophic failures occur and/or are
17 designed to prevent failure events which could lead to the complete loss of a
18 substation.”²⁷ Running a cost benefit analysis on failed substations like McGraw
19 Substation, which has been running on temporary solutions since 2021, would not
20 provide any useful conclusions.²⁸ The investments being challenged by the AG are
21 necessary to provide continued reliable service to DTE Electric’s existing
22 customers. It bears emphasis that those temporary solutions are provided by Mobile

²⁴ Exhibit AG-5 contains the following discovery responses: AGDE-6.173a, AGDE-6.173b, AGDE-6.173c, and AGDE-6.173f

²⁵ Witness Robinson’s Revised Direct Testimony, pp. 83-108

²⁶ Witness Coppola’s Direct Testimony, p. 39, ll. 1-4

²⁷ Exhibit AG-5, AGDE-6.173f, p. 5

²⁸ Witness Robinson’s Revised Direct Testimony, p. 88, ll. 4-17

Line
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1 Fleet Program assets, which is another disallowance sought by Witness Coppola in
2 the instant case.

3

4 **Q33. Should the Commission adopt AG-MN Witness Coppola's recommendation to**
5 **disallow Substation Risk projects totaling \$27,104,000 in 2025 and \$5,625,000**
6 **in 2026?**

7 A33. No. The Commission should reject AG-MN Witness Coppola's recommendation
8 to disallow Substation Risk projects totaling \$27,104,000 in 2025 and \$5,625,000
9 in 2026 because these investments are necessary to provide service to the
10 Company's customers. The substation risk projects were uncontested in the
11 Company's prior rate case, Case No. U-21534.

12

13 **Major Event Risk – Mobile Fleet Program**

14 Rebuttal Issue 10: Rebuttal Issue 1: AG-MN Witness Coppola's statements on lack of
15 support for the Mobile Fleet Program

16 **Q34. What recommendation does AG-MN Witness Coppola make regarding the**
17 **Company's Mobile Fleet Program?**

18 A34. Witness Coppola recommends disallowance of \$5.5 million from the 2026
19 forecasted capital expenditure shown in Case No. U-21860, Exhibit A-12, Schedule
20 B5.4, p. 10, line 30.²⁹

21

22 **Q35. What are the cited reasons for disallowance?**

23 A35. Witness Coppola cites "lack of pertinent information on utilization of the mobile
24 equipment and no cost/benefit analysis for the major equipment purchases make it

²⁹ Witness Coppola's Direct Testimony, p. 42, ll. 1-2

Line
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1 difficult to justify the purchase of large items, such as the mobile substation at a
2 cost of \$5.5 million” to support his proposed disallowance.³⁰

3

4 **Q36. Did the Company support the usage of Mobile Fleet program, specifically**
5 **mobile substations?**

6 A36. Yes. As explained in my revised direct testimony, the Mobile Fleet program
7 provides short- to medium-term solutions for major outages while also supporting
8 customers’ power needs during planned work on the system. While portable
9 substations were initially intended to support maintenance and upgrades at single
10 transformer sites, the Company has also been able to use these assets for emergent
11 situations.³¹ Two cited examples include the Snover and McGraw Substations.³²
12 The Company has been using these assets to serve customers fed by the McGraw
13 substation since 2021, specifically to support the needs of over 1,400 Dearborn-
14 area customers while continuing to work on a longer term permanent substation
15 solution.

16 **Q37. What is the value of the Mobile Fleet program to DTE Electric customers?**

17 A37. Absent this program, approximately 1,400 customers served by the McGraw
18 substation would have experienced a very extended service interruption. The
19 mobile fleet units are a critical component of the Company’s contingency planning
20 strategy, enabling timely restoration of service in the event of substation equipment
21 failures. Additionally, these assets support planned system improvements while
22 avoiding customer outages. While their deployment has not historically been

³⁰ Witness Coppola’s Direct Testimony, p. 41, ll. 13-15

³¹ Witness Robinson’s Revised Direct Testimony, p. 109, ll. 3-19

³² Witness Robinson’s Revised Direct Testimony, p. 109-110 (Snover), p. 88 (McGraw)

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1 centrally tracked, their inherent value in maintaining electrical service to large
2 numbers of customers and rapid deployment capability speaks for itself in terms of
3 maintaining service continuity and operational flexibility. I am confident that the
4 Mobile Fleet program provides excellent service to customers many times each
5 calendar year.

6

7 **Q38. Is the Company planning to purchase a new portable substation in 2026 with**
8 **the \$5.5 million being proposed for disallowance?**

9 A38. No. As noted in discovery response AGDE-6.174a provided in Exhibit AG-6, the
10 \$5.5 million quoted is a portable substation component but specifically represents
11 essential portable storage sites.³³ Specifically, this investment represents the
12 construction of five different sites geographically spread throughout the
13 Company's service territory, to support faster deployment when needed. Each site
14 is designed to accommodate up to three 49,000-pound portable substations with oil
15 containment on a concrete slab and will supply auxiliary power used to maintain
16 essential systems such as monitoring, heating, or battery charging through 200A
17 subpanels to each of the three portable substations.

18

19 **Q39. Why does the Company need storage locations for the portable substations?**

20 A39. Storing portable substations in appropriate locations with adequate power
21 infrastructure helps preserve equipment condition and reduce premature component
22 replacement. This includes maintaining charged batteries and operating heaters to
23 prevent moisture buildup, which in turn minimizes asset wear and fuel costs.
24 Furthermore, by maintaining five strategically placed sites across the 7,600 square-

³³ AG-6, ADGE-6.174a, p. 2

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1 mile DTE Electric service territory, which means Mobile Fleet program assets will
2 be positioned closer to potential problem areas, allowing for faster and more
3 efficient deployment when needed.

4

5 **Q40. One stated reason for the AG's proposed Mobile Fleet Program disallowance**
6 **was "no cost/benefit analysis." Do you agree that investments in this program**
7 **require such an analysis to support cost recovery for these storage locations?**

8 A40. No, the Company's investments in its Mobile Fleet Program assets offer such
9 substantial and demonstrable benefits to its customers that a formal analysis should
10 not be required. Through this program, including the 2026 projected investment,
11 customers gain rapid deployment of resources that can maintain service during
12 planned or emergent outage events. Considering these comprehensive benefits of
13 the program and the lack of viable alternatives, conducting a cost/benefit analysis
14 regarding storage locations for existing equipment does not appear warranted.

15

16 **Q41. Should the Commission adopt AG-MN Witness Coppola's recommendation to**
17 **disallow \$5.5 million allocated for Mobile Fleet - portable substation storage?**

18 A41. No. The Commission should reject AG Witness Coppola's recommendation to
19 disallow \$5.5 million allocated for the Mobile Fleet program to build portable
20 substation storage. The units in the mobile fleet program are critical assets designed
21 to restore power to large numbers of customers during unexpected equipment
22 failures. To ensure they are fully operational when needed, these units must be
23 proactively maintained and strategically managed.

24

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1 **Preventative and Corrective Maintenance**

2 Rebuttal Issue 11: AG-MN Witness Coppola inaccurate claims regarding insufficient
3 evidence for incremental O&M investments for preventative and corrective maintenance
4 activities

5 **Q42. What recommendations does AG-MN Witness Coppola have regarding**
6 **incremental O&M investments for preventative and corrective maintenance**
7 **activities?**

8 A42. Witness Coppola proposes an O&M disallowance of \$14.6 million for Preventative
9 and Corrective Maintenance in the projected test year.³⁴ The proposed
10 disallowances represent \$7.3 million for Preventative Maintenance (PM) and \$7.3
11 million for Corrective Maintenance (CM). These sums represent the full amount
12 shown in footnote 6 to Exhibit A-13, Schedule 1 C5.6.

13

14 **Q43. What are AG-MN Witness Coppola's cited reasons for his proposed**
15 **disallowance?**

16 A43. Witness Coppola stated that "[t]hose same amounts are included in the 2024 O&M
17 expense schedule in Exhibit AG-40."³⁵ Elaborating on that point Witness Coppola
18 stated "[c]ustomers should not pay twice for maintenance work that should have
19 been done in prior years with O&M expenses included in rates in those years."³⁶
20 While this statement was made for Corrective Maintenance, he subsequently stated
21 that his Preventative Maintenance rationale is similar.³⁷

³⁴ Witness Coppola's Direct Testimony, p. 112, l. 10

³⁵ Witness Coppola's Direct Testimony, p. 113, l. 4

³⁶ Witness Coppola's Direct Testimony, p. 113, ll. 12-14

³⁷ Witness Coppola's Direct Testimony, p. 113-4, ll. 17-19;1-2

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1 **Q44. Did the Company ask customers to pay twice for the same work?**

2 A44. No. The Company is not seeking double recovery. Exhibit A-40, p. 2, column (c)
3 shows the 2024 O&M actuals. Preventative and Corrective Maintenance
4 investments were included in the “Other Adjustment,” Exhibit AG-40, p. 2, column
5 (j), which forms part of the “Projected Adjustments” for the “Projected Test Period”
6 in column (f). If the referenced work had been completed, it would have appeared
7 in the 2024 O&M actuals, Exhibit AG-40, p. 2, column (c), and subsequently been
8 removed from the maintenance backlog.

9
10 **Q45. How would you evaluate the evidence AG-MN Witness Coppola presents, in**
11 **regard to Corrective Maintenance, to support his proposed disallowance?**

12 A45. Witness Coppola claims “[f]rom Mr. Robinson’s testimony and the discovery
13 response, it is evident that the Company has deferred undertaking corrective
14 maintenance in prior years, despite receiving increases in O&M expense recovery,
15 and now has a backlog that it seeks to resolve by requesting incremental O&M
16 expense again.”³⁸ The only portion of testimony cited by Witness Coppola
17 regarding Corrective Maintenance describes the existence of the backlog.³⁹ One of
18 the cited discovery responses presented in AG-43⁴⁰ directly stated the incremental
19 Corrective Maintenance line item “does not represent any actual historical O&M
20 expenditures.” Collectively, his proposed disallowance for Corrective Maintenance
21 appears to mischaracterize the facts.

³⁸ Witness Coppola’s Direct Testimony, p. 113, l. 4

³⁹ Witness Robinson’s Revised Direct Testimony, p. 42-43

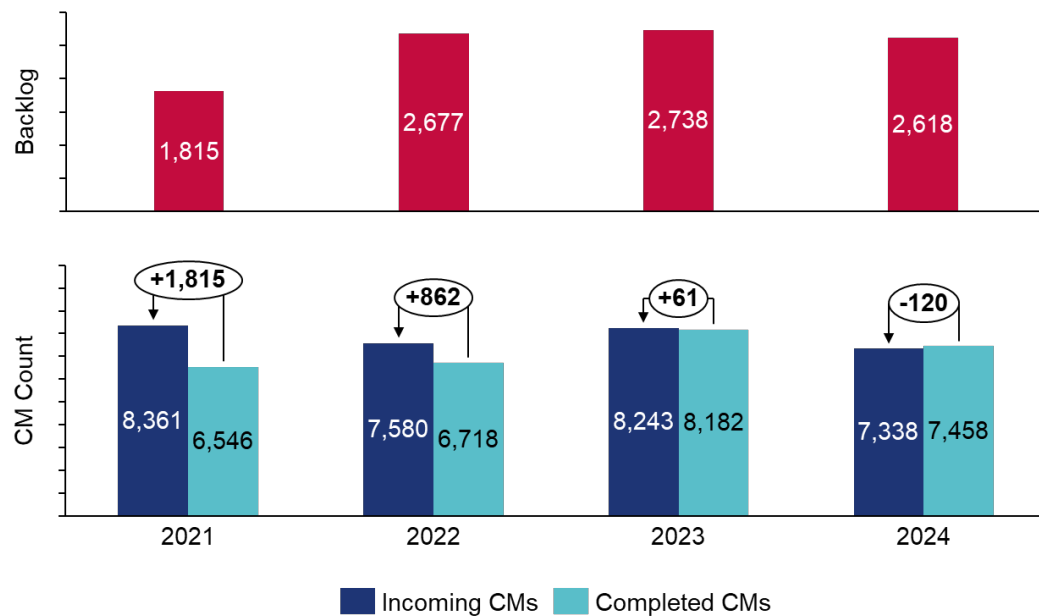
⁴⁰ AG-43 cites the following discovery responses: AGDE-6.170a (PM), AGDE-6.171a (PM), AGDE-6.172 (PM), AGDE-6.176bi (CM), and AGDE-6.176bii (CM).

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1 **Q46. Did the Company defer corrective maintenance as claimed by Witness**
2 **Coppola?**

3 A46. No. The Company is performing Corrective Maintenance, but incoming demands
4 surpass the available investment. Corrective Maintenance activities come from
5 electrical or structural system components that require extensive repair or
6 replacement and are identified during preventative maintenance inspections or
7 customer outages. Figure 1 shows incremental backlog growth from 2021 to 2024
8 despite ongoing work, which confirms the Company is not deferring work.

9 **Figure 1 Corrective Maintenance Backlog Growth From 2021-2024**



10 **Q47. What evidence does AG-MN Witness Coppola present regarding Preventative**
11 **Maintenance to support his proposed disallowance?**

12 A47. Witness Coppola asserts that, “[i]n response to additional discovery, the Company
13 stated that there are no changes proposed and the Company is carrying out the

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1 current inspection cycles shown in Table 6 on page 40 of Mr. Robinson's
2 testimony."⁴¹ The referenced discovery is included in Exhibit AG-43.⁴²
3 Discovery response AGDE-6.170a, Exhibit AG-43, p. 1, inquired about Table 6
4 and whether the proposed cycles were new. The response clarified that the cited
5 cycles reflect both current and historical inspection practices and are not newly
6 proposed. Likewise, discovery response AGDE-6.171a, Exhibit AG-43, p. 2,
7 addressed Tables 7 and 8, confirming that these do not contain newly proposed
8 activities.

9
10 It appears there may be a misunderstanding regarding the Preventative Maintenance
11 details; Witness Coppola describes the Company as "carrying out"⁴³ the current
12 inspection cycles, whereas the Company has merely referenced the standard cycle
13 times. In fact, the existing backlog has accumulated due to funding levels in the
14 Company's rates that are insufficient to support the standard inspection and
15 maintenance cycles along with corrective items found during customer outages. For
16 this reason, the Company requested an incremental adjustment as detailed in
17 Exhibit AG-43.⁴⁴

18
19 **Q48. Should the Commission adopt AG-MN Witness Coppola's proposed**
20 **recommendation to disallow \$14.6 million in O&M expenses for Preventative**
21 **and Corrective Maintenance in the test?**

⁴¹ Witness Coppola's Direct Testimony, p. 112

⁴² AG-43 cites the following discovery responses: AGDE-6.170a (PM), AGDE-6.171a (PM), AGDE-6.172 (PM), AGDE-6.176bi (CM), and AGDE-6.176bii (CM).

⁴³ Witness Coppola's Direct Testimony, p. 112

⁴⁴ Exhibit AG-43, Discovery Response AGDE-6.172, p. 2

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1 A48. No. The Commission should reject AG-MN Witness Coppola's proposed
2 recommendation to disallow \$14.6 million in O&M expenses for Preventative and
3 Corrective Maintenance in the projected test year.

4

5 **Q49. Does this conclude your rebuttal testimony?**

6 A49. 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

REBUTTAL TESTIMONY

OF

RYAN M. STOWE

"PUBLIC"

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF RYAN M. STOWE

Line
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1 **Q1. Please state your full name, title, business address and by whom you are employed?**

2 A1. My name is Ryan M. Stowe (he/him/his). My business address is One Energy Plaza,
3 Detroit, Michigan, 48226 and I am employed by DTE Electric Company as the Vice
4 President of Reliability Operations.

5

6 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
7 **Company (DTE Electric or Company)?**

8 A2. Yes.

9

10 **Purpose of Testimony**

11 **Q3. What is the purpose of your rebuttal testimony?**

12 A3. The purpose of this testimony is to rebut certain positions and recommendations for
13 disallowances of capital projects as proposed by certain witnesses that provided
14 direct testimony in the instant case. These witnesses include:

- 15 • Michigan Public Service Commission (MPSC) Staff (Staff) Witnesses Shi
16 and Evans;
- 17 • Michigan Attorney General (AG), Michigan Environmental Council
18 (MEC), Natural Resources Defense Council (NRDC), collectively referred
19 to as “AG-MN” Witness Stephens;
- 20 • Ecology Center, Environmental Law & Policy Center, Union of Concerned
21 Scientists, and Vote Solar, collectively referred to as the Clean Energy
22 Organizations, or “CEO”, Witness Volkmann;
- 23 • Michigan Environmental Council (MEC), Natural Resources Defense
24 Council (NRDC), and Citizens Utility Board of Michigan (CUB),
25 collectively referred to as “MNC” Witness Woolley; and

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- 1 • Association of Businesses Advocating Tariff Equity (ABATE) Witnesses
2 York and Fitzhenry

3

4 The absence of a discussion of other matters in my rebuttal testimony should not
5 be taken as an indication of agreement with other aspects of any intervenor's
6 testimony.

7

8 **Q4. Are you sponsoring any exhibits in this proceeding?**

9 A4. Yes. I am sponsoring the following exhibits:

10	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
11	A-50	QQ1	IRM & Rate Case Ramp Rate Analysis
12	A-50	QQ2	Discovery Responses STDE-20.1a-r
13	A-50	QQ3	Discovery Responses from STDE-6
14	A-50	QQ4	NDA CEII Discovery Response MSNCDE-4.2civ &
15			System Loading Data
16	A-50	QQ5	Discovery Responses MNSCDE-4.4ai &
17			MNSCDE-4.7bii
18	A-50	QQ6	Hypothetical Substation Loading Scenario
19	A-50	QQ7	Discovery Responses CEODE-1.3a, MNSCDE-
20			3.30a, MNSCDE-3.30c & Subtransmission Project
21			Pool

22

23 **Q5. Were these exhibits prepared by you or under your direction?**

24 A5. Yes, they were.

25

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1 **Q6. How is your testimony organized?**

2 A6. There are five specific topics I will address in my rebuttal testimony, as listed
3 below, in addition to a few general rebuttal topics I cover at the end of my
4 testimony. A detailed discussion of why the intervenors' recommendations should
5 not be accepted by the Commission follows.

Line
No.

1	Rebuttal Contents	
2	Purpose of Testimony	1
3	Rebuttal Topic 1: Staff Witness Shi’s recommendations regarding the Company’s	
4	Infrastructure Redesign & Modernization projects	5
5	Table 1 Redesign Project Reductions Proposed by Witness Shi.....	6
6	Table 2 Rate Case Capital Expenditure Request for the Projects without IRM	
7	Investment (\$M).....	8
8	Table 3 Combined Rate Case and IRM Capital Expenditure Request for 2025-	
9	2026 (\$M)	9
10	Table 4 DTE’s Implied Secondary Network Cable Unit Cost	27
11	Rebuttal Topic 1 Conclusion	37
12	Rebuttal Topic 2: AG-MN Witness Stephens’ recommendations regarding the	
13	Company’s System Loading projects.....	38
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15	Table 5 Substation Load Forecast for the 12 Projects with Recommended	
16	Disallowances	44
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19	Rebuttal Topic 3: AG-MN Witness Stephens’ recommendations regarding the	
20	Company’s Conversions program.....	53
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23	recommendations regarding the Company’s Strategic Undergrounding Program .	59
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25	Witness Volkmann’s recommendations regarding the Company’s IRM level of	
26	investments in the Subtransmission Redesign & Rebuild program.....	66
27	Table 8 Subtransmission Redesign & Rebuild Rebuttal Points to Witness	
28	Stephens 73	
29	General Infrastructure Redesign & Modernization Rebuttal Points	76
30	Table 9 General Rebuttal Topics.....	77
31		
32		

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1 **Rebuttal Topic 1: Staff Witness Shi's recommendations regarding the Company's**

2 **Infrastructure Redesign & Modernization projects**

3 **Q7. What does Witness Shi recommend with respect to the Company's**
4 **Infrastructure Redesign & Modernization projects?**

5 A7. Witness Shi expressed her support and acknowledged the need for several of the
6 Company's strategic capital projects, however she recommended reductions across
7 20 projects in the Subtransmission Redesign & Rebuild, 4.8kV Conversion, and
8 System Loading programs, totaling \$90.2 million¹. The Company notes that these
9 projects are within the Infrastructure Redesign & Modernization ("Redesign")
10 pillar supported by my revised direct testimony and exhibits.

11

12 **Q8. What did Witness Shi state with respect to those Infrastructure Redesign &**
13 **Modernization projects for which she recommended reduction?**

14 A8. Witness Shi stated that some of the Company's proposed projects demonstrate
15 unsubstantiated projected investment ramp rates, historical underspending, and
16 insufficient project documentation on the record; I summarize Witness Shi's
17 commentary for each project throughout Rebuttal Topic 1 below.

18

19 **Q9. How do you respond to Witness Shi's recommendations regarding the**
20 **Company's Infrastructure Redesign & Modernization projects?**

21 A9. I do not agree with Witness Shi's recommended reductions. A summary of Witness
22 Shi's proposed reductions to the Company's Redesign projects can be found in
23 Table 1 below (including her original reference numbers 8 – 27 for these 20
24 projects). I address each project individually in the subsequent Q&As. The

¹ Witness Shi DT, table on p. 39, project Nos. 8-27.

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Company notes that several of Witness Shi's proposed reductions were calculated utilizing the inflation rates of 2.73% for 2025 and 2.66% for 2026 as proposed by Staff Witness Ufolla². Inflation-related reductions are discussed in more detail and rebutted in Company Witness Bruzzano's rebuttal testimony.

Table 1 Redesign Project Reductions Proposed by Witness Shi

#	Project Name	IRM Project	Reduction for 2025	Reduction for 2026
8	Subtransmission Redesign & Rebuild: Transformer High Side Protection Program		\$4,563,028	\$3,011,502
9	Subtransmission Redesign & Rebuild: Trunk 3509		\$1,501,600	-
10	CODI: Alfred Substation Expansion		\$2,248,800	\$359,018
11	CODI: Targeted Network Secondary Cable Replacement		\$1,232,959	\$102,303
12	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade)	X	-	\$19,866,548
13	4.8 kV CC: Calla Circuit Conversion and Phase 2	X	-	\$885,000
14	4.8 kV CC: Grosse Pointe Substation and Circuit Conversion - North		-	\$300,000
15	4.8 kV CC: Melvindale		-	\$360,000
16	System Loading: Jewell		-	\$400,000
17	Subtransmission Redesign & Rebuild: Trunk 7105		-	\$200,000
18	Subtransmission Redesign & Rebuild: Reverse Power Relay Scheme Program		\$200,000	\$200,000
19	CODI: Garfield (All projects)	X	-	\$14,173,098
20	CODI: Howard Conversion	X	-	\$4,042,844
21	4.8 kV CC: ISO Conversion Program	X	-	\$12,634,190
22	4.8 kV CC: New Baltimore	X	-	\$2,900,000
23	4.8 kV CC: Belleville Substation and Circuit Conversion	X	-	\$1,602,400
24	4.8 kV CC: Ann Arbor AC Network Conversion	X	\$660,000	\$1,013,400
25	4.8 kV CC: Grosse Pointe Substation and Circuit Conversion		-	\$683,769
26	4.8 kV CC: Hemlock Decommissioning and Circuit Conversion	X	\$300,000	\$239,000
27	System Loading: Grenada		\$10,266,233	\$6,233,274
Total:			\$20,972,620	\$69,206,472

Q10. Before discussing each project, do any of the Redesign projects proposed for reduction by Witness Shi have expenditures in the Infrastructure Recovery Mechanism ("IRM")?

A10. Yes, there are nine-line items included in Table 1 with expenditures with costs that will be recovered through both the IRM and base rates. While Witness Shi may identify additional reasons for project reductions, which I will address in subsequent Q&As, she generally states that the requested capital expenditures for

² Ufolla DT, p. 24, Lines 4-11

Line
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1 these projects has significantly increased in the instant case from 2025 to 2026 and
2 uses that increase as the basis for her recommended reductions.

3

4 **Q11. Is Witness Shi's analysis of the rate case costs for these projects without the**
5 **IRM investments an important gap in her ability to estimate an accurate**
6 **program or project ramp rate?**

7 A11. Yes. Witness Shi's analysis does not capture all of the investment in these projects
8 prior to 2026, because some of these costs were slated for recovery through the
9 IRM. Based on the Commission's Order in Case No. U-21534, beginning in 2026
10 the cost of these conversion projects will only be recovered through base rates.
11 However, the physical work on these projects has been ongoing in 2025 (and
12 before) and will continue in 2026. Inclusion of both the cost for investment
13 recovered through the IRM and through base rates provides a more wholistic view
14 of the expenditures being undertaken on these projects and demonstrates that
15 Witness Shi's analysis omitted a substantial amount of work and expenditures from
16 her evaluation of many projects.

17

18 Table 2 below shows the 2025 and 2026 projected capital expenditures in the instant
19 case for the projects proposed for reduction by Witness Shi with investments in the
20 IRM. These projects show a \$101 million (342%) increase in expenditures from
21 2025 to 2026, based solely on the limited view of electric rate case ("ERC")
22 investments.

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1 **Q13. What information does Exhibit A-12 Schedule B5.4.8 contain that was**
2 **overlooked in Witness Shi's analysis?**

3 A13. Exhibit A-12 Schedule B5.4.8 filed in the instant case details the revenue recovery
4 partition of Distribution Plant projects between base rates and the IRM. The base
5 rates and IRM partition exhibit includes seven projects for which Witness Shi
6 recommends reduction citing unsubstantiated investment ramp rates between 2025
7 and 2026; an additional three projects in this category are included in the
8 Company's 2026 IRM Plan filed under Case No. U-21534³. The Company notes
9 that the last page of each project summary in Exhibit A-23 Schedule M6 includes
10 footnote 1 stating "\1 Total cost includes historical actuals and forecast amounts
11 beyond the test year, which may include IRM investments." This highlights that
12 there may be ongoing investments under the IRM that are shown in a future IRM
13 Plan filing once all previous investments are ready to be in-serviced in the IRM
14 Plan year.

15
16 These 10 projects are listed in Exhibit A-50 Schedule QQ1 "IRM & Rate Case
17 Ramp Rate Analysis" with an IRM cross reference source identified for each
18 project.

19
20 These projects are part of the Company's 4.8kV conversions programs which were
21 previously identified for cost recovery through the IRM but are now included for
22 cost recovery in base rates following the Commission's directive to remove
23 conversions from the IRM⁴.

³ Two of these projects, System Conduit and Circuits 8098 & 8632, are part of the broader 4.8kV CC: I-94 Substation and Circuit Conversion (Promenade); Witness Shi's proposed disallowance is at the broader project level as captured in item #12 in Table 1

⁴ U-21534 – Commission Order, January 23, 2025, p. 301

Line
No.

1 **Q14. Can you explain how you calculated the correct investment ramp rates which**
2 **include IRM spend?**

3 A14. Yes. In Exhibit A-50 Schedule QQ1 “IRM & Rate Case Ramp Rate Analysis”,
4 columns (b) – (e) shows the investment amounts for each project presented in the
5 instant electric rate case (“ERC”) and columns (f) – (h) show the 2023-2025
6 expenditures to be in-serviced in the IRM.

7

8 Column (i) shows the sum of the 2025 ERC and IRM investment amounts for each
9 project; column (j) shows the projected 2026 capital expenditures presented in the
10 instant case (also shown in column (e)).

11

12 Witness Shi’s analysis is based on a ramp rate from 2025 to 2026 viewing only the
13 ERC investment amounts; this ramp rate is shown in column (k)⁵. When accounting
14 for the IRM investment amounts, the ramp rate shown in column (l) demonstrates
15 a more modest increase⁶. For instance, using the Promenade project totals shown
16 on line 7, column (k) shows a ramp rate of 402% when viewing only the ERC
17 investments. When accounting for the IRM dollars, line 7, column (l) shows a ramp
18 rate of 16% between 2025 and 2026. I detail this same ramp rate comparison for
19 each of these projects in the subsequent Q&As.

20

21 Exhibit A-50 Schedule QQ1 column (l) shows the correct, modest investment trend
22 for these 10 projects from 2023 through 2026. These investment trends and 2025-

⁵ The ERC-Only Run Rate is calculated with the formula: $\left(\frac{2026 \text{ ERC Forecast}}{2025 \text{ ERC Forecast}} - 1\right) * 100$

⁶ The IRM+ERC Ramp Rate is calculated with the formula: $\left(\frac{2026 \text{ ERC Forecast}}{(2025 \text{ ERC Forecast}) + (2025 \text{ IRM})} - 1\right) * 100$

Line
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1 to-2026 ramp rates demonstrate that Witness Shi's proposed \$58.3million reduction
2 for these 10 projects should not be accepted by the Commission.

3

4 **Q15. How do you respond to Witness Shi's testimony regarding proposed**
5 **reductions for specific projects with planned IRM investments?**

6 A15. I disagree with her proposed reductions and will address each project in Table 1
7 individually, starting with those with IRM investments, as identified by an "X" in
8 Table 1.

9

10 **Q16. What does Witness Shi recommend regarding the Company's '4.8kV CC: I-**
11 **94 Substation and Circuit Conversion (Promenade)' projects (#12 in Table 1)?**

12 A16. Acknowledging that there are five separate but related Promenade projects in the
13 instant case, Witness Shi expresses her support for executing these projects "to
14 further ensure safety and reliability and also provide for load to be transferred⁷."
15 Stating that the 2023-2030 scope is similar work, Witness Shi then expressed a
16 concern about the increase in project funding from 2025 to 2026. Based on this
17 year-to-year increase, she then proposes a reduction to the 2026 projected test year
18 of \$19.9 million because the 2026 projected test year expenditure of \$25.3 million
19 is nearly five times the 2025 projected expenditures for these five projects⁸. She
20 arrived at this proposed reduction by calculating the average 2023-2025
21 expenditures, inflating the average to 2026, and recommending a reduction of the
22 expenditures above her calculated 2026 forecast.

⁷ Shi DT, p. 24, Lines 1-2

⁸ Shi DT, p. 24, Lines 2-9

Line
No.

1 **Q17. How do you respond to Witness Shi's proposed reductions on the Promenade**
2 **projects?**

3 A17. I disagree. Similar to the arguments I've made above, Witness Shi's year-to-year
4 analysis fails to take into account that the Promenade projects have expenditures
5 being recovered through both the IRM and base rates and are included in my
6 discussion regarding projects in the IRM above. Per Exhibit A-50 Schedule QQ1,
7 Line 7, columns (k) and (l), the ramp rate from 2025 to 2026 for the Promenade
8 projects is a modest 16%, not 402% when only accounting for rate case investment
9 amounts as Witness Shi does; part of this project was also included in Exhibit A-
10 12 Schedule B5.4.8. This is also due, in part, to the fact that two of the Promenade
11 projects were ramping down as they neared completion in 2023 (Below Grade) and
12 2024 (Above Grade) while the other three Promenade projects were beginning to
13 ramp up. Because the ramp rate from 2025 to 2026 for these projects is only a
14 modest 16%, I believe that Witness Shi's proposed reductions to the Promenade
15 projects should be rejected; I address her use of prior year historical averages at the
16 end of Rebuttal Topic 1.

17

18 **Q18. What does Witness Shi recommend regarding the Company's '4.8kV CC:**
19 **Calla Circuit Conversion and Phase 2' project (#13 in Table 1)?**

20 A18. Witness Shi states that "Staff is in line with the Company's idea to do the
21 conversion" but then claims that "phase 2 is a new capital project within the current
22 rate case⁹." On the basis that this project is new, Witness Shi recommends a 20%
23 reduction of \$0.9 million to the 2026 projected test year.

⁹ Shi DT, p. 25, Lines 8-9

Line
No.

1 **Q19. How do you respond to Witness Shi's proposed reductions to the '4.8kV CC:**
2 **Calla Circuit Conversion and Phase 2' project?**

3 A19. I disagree. My arguments include the in and out of the IRM discussion above. The
4 '4.8kV CC: Calla Circuit Conversion and Phase 2' project is not a new project
5 within the current case. As shown in Exhibit A-12 Schedule B5.4, page 12, Line
6 53, the Company had expenditures in for this phase of the Calla project in 2023.
7 The Company also notes that this project was presented in Case No. U-21297
8 Exhibit A-12 Schedule B5.4, page 10, Line 59 and Case No. U-21534 Exhibit A-
9 12 Schedule B5.4, page 16, Line 84 before being included in the Company's IRM.
10 As previously noted this is one of the projects originally identified for cost recovery
11 through the IRM, but is now included in base rates following the Commission's
12 directive to remove conversions from the IRM.

13
14 Per Exhibit A-50 Schedule QQ1, Line 14, columns (k) and (l), the ramp rate from
15 2025 to 2026 for the Calla project is a modest 11% when investments in prior years
16 identified as part of the IRM are included; this project was also included in Exhibit
17 A-12 Schedule B5.4.8. Witness Shi's proposed reductions to the Calla project
18 should be rejected.

19

20 **Q20. What does Witness Shi recommend regarding the Company's 'CODI:**
21 **Garfield' projects (#19 in Table 1)?**

22 A20. After highlighting actual expenditures in 2023 and 2024, Witness Shi states that the
23 work scope for 2023-2026 is similar. She goes on to state that because "2026 work
24 appears similar in type to prior years but with sharply higher request and without a
25 comprehensive plan detailing how the full amount will be spent," the projected test

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1 year expenditure of \$33.8 million should be reduced by \$14.2 million¹⁰. Witness
2 Shi calculates this reduction by calculating a 2023-2025 average, inflating it by
3 2.66% to 2026 dollars, and recommending a reduction of the expenditures above
4 her calculated 2026 forecast¹¹.

5

6 **Q21. How do you respond to Witness Shi's proposed reductions to the 'CODI:**
7 **Garfield' projects?**

8 A21. I disagree. The 'CODI: Garfield' projects have expenditures in both the IRM and
9 base rates and are included in my discussion regarding projects in the IRM above.
10 Per Exhibit A-50 Schedule QQ1, Line 13, columns (k) and (l), the ramp rate from
11 2025 to 2026 for the 'CODI: Garfield' projects is a modest 25%, not 134% when
12 only accounting for rate case investment amounts as Witness Shi does; this project
13 was also included in Exhibit A-12 Schedule B5.4.8. Witness Shi's proposed
14 reductions to the 'CODI: Garfield' projects should be rejected; I address her
15 comments regarding the use of historic work scope and her request for
16 comprehensive plan detailing at the end of Rebuttal Topic 1.

17

18 **Q22. What does Witness Shi recommend regarding the Company's 'CODI:**
19 **Howard Conversion' project (#20 in Table 1)?**

20 A22. Witness Shi acknowledges the Company's approximate construction schedule
21 shown on page 262 of Exhibit A-23 Schedule M6 showing work starting in 2022
22 and ending in 2028 on the 'CODI: Howard Conversion' project, but states that the
23 "there is little evidence of earlier phase execution prior to the current case, and the
24 filing does not include a comprehensive plan sufficient to support the entire 2026

¹⁰ Shi DT, p. 31, Lines 4-6

¹¹ Shi DT, p. 31, Lines 6-8

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1 request¹².” She goes on to recommend a 20% reduction of \$4.0 million to the 2026
2 projected test year “as appropriate unless the Company provides detailed
3 engineering packages, procurement status, a list of long-lead materials, a
4 description of construction sequencing, and a customer conversion plan aligned
5 with outage constraints.¹³”

6

7 **Q23. How do you respond to Witness Shi’s proposed reductions to the ‘CODI:**
8 **Howard Conversion’ project?**

9 A23. I disagree. The ‘CODI: Howard’ project has expenditures in both the IRM and base
10 rates and is included in my discussion regarding projects in the IRM above. Per
11 Exhibit A-50 Schedule QQ1, Line 15, columns (k) and (l), the ramp rate from 2025
12 to 2026 for the ‘CODI: Howard’ project is a modest 8%, when investments in prior
13 years included the IRM are considered; this project was also included in Exhibit A-
14 12 Schedule B5.4.8. Witness Shi’s proposed reductions to the ‘CODI: Howard’
15 project should be rejected; I address her comments regarding granular details at the
16 end of Rebuttal Topic 1.

17

18 **Q24. What does Witness Shi recommend regarding the Company’s ‘4.8kV CC: ISO**
19 **Conversion Program’ (#21 in Table 1)?**

20 A24. Stating that the ‘4.8kV CC: ISO Conversion Program’ has “similar types of
21 engineering and construction work from 2024 onward” and that the “more than
22 three-fold increase in 2026 is insufficiently supported,” Witness Shi recommends
23 reduction of \$12.6 million to the projected test year; she arrived at this proposed
24 reduction by inflating the 2025 projected capital expenditure to 2026 dollars and

¹² Shi DT, p. 31, Line 19 – p. 32, Line 1

¹³ Shi DT, p. 32, Lines 1-5

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1 recommending a reduction of the expenditures above her calculated 2026 forecast
2 “absent a detailed workplan tying quantities, unit cost, and schedules to the test-
3 year request”¹⁴.
4

5 **Q25. How do you respond to Witness Shi’s proposed reductions to the ‘4.8kV CC:
6 ISO Conversion Program?’**

7 A25. I disagree. The ISO Conversion program has expenditures in both the IRM and base
8 rates and is included in my discussion regarding projects in the IRM above. Per
9 Exhibit A-50 Schedule QQ1, Line 16, columns (k) and (l), there is actually a
10 decrease in investments in the ISO Conversion program from 2025 to 2026, not a
11 “more than three-fold increase” as Witness Shi believes; the ISO Conversion
12 program was also included in Exhibit A-12 Schedule B5.4.8. Witness Shi’s
13 proposed reductions to the ‘4.8kV CC: ISO Conversion Program’ should be
14 rejected; I address her comments regarding a detailed workplan at the end of
15 Rebuttal Topic 1.
16

17 **Q26. What does Witness Shi recommend regarding the Company’s ‘4.8kV CC: New
18 Baltimore’ project (#22 in Table 1)?**

19 A26. Witness Shi states that the Company did not invest the 2024 amount requested for
20 the ‘4.8kV CC: New Baltimore’ project in Case No. U-21534, does not plan to
21 invest in this project in 2025, and “the current case projects \$14,500,000 for 2026
22 with a similar schedule yet provides limited detail demonstrating readiness to
23 execute at that level in the test year¹⁵.” She goes on to recommend a 20% reduction
24 of \$2.9 million to the 2026 projected test year “unless the Company provides

¹⁴ Shi DT, p. 33, Lines 1-7

¹⁵ Shi DT, p. 33, Line 21 – p. 34, Line 2

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1 executed or draft agreements, a detailed engineering package, and a resource-
2 loaded schedule that supports the test-year spend readiness¹⁶.”

3

4 **Q27. How do you respond to Witness Shi’s proposed reductions to the ‘4.8kV CC:
5 New Baltimore’ project?**

6 A27. I disagree. As noted at the bottom of page 13 of Exhibit A-12 Schedule B5.4, “1/
7 System Loading: New Baltimore/Chesterfield in U-21534 was separated into two
8 projects - System Loading: Chesterfield and 4.8kV CC: New Baltimore.” As
9 previously noted this is one of the projects previously identified for cost recovery
10 through the IRM but is now included in base rates following the Commission’s
11 directive to remove conversions from the IRM. The ‘System Loading: Chesterfield’
12 project was to be included in base rates while the New Baltimore conversion project
13 was to be included in the IRM.

14

15 Per Exhibit A-50 Schedule QQ1, Line 17, columns (i) and (j), the ‘4.8kV CC: New
16 Baltimore’ project has had investment in the IRM in prior years. Witness Shi’s
17 proposed reductions to the New Baltimore project should be rejected; I address her
18 comments regarding additional detailed information at the end of Rebuttal Topic 1.

19

20 **Q28. What does Witness Shi recommend regarding the Company’s ‘4.8kV CC:
21 Belleville Substation and Circuit Conversion’ project (#23 in Table 1)?**

22 A28. While noting that “Staff agrees with decommissioning the overloaded 4.8kV side
23 and expanding the 13.2kV side,” Witness Shi states that page 274 of Exhibit A-23
24 Schedule M6 indicates engineering and design in 2024 followed by construction

¹⁶ Shi DT, p. 34, Lines 3-5

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1 from 2025-2027, but “the record shows no completed activities to date” and that
2 “the Company should explain the delays and provide a comprehensive test-year
3 plan¹⁷.” She goes on to recommend a 20% reduction of \$1.6 million to the projected
4 test year and “requests for DTE to provide a detailed scope, milestone schedule,
5 and cost breakdown for engineering, procurement, and construction activities¹⁸.”

6

7 **Q29. How do you respond to Witness Shi’s proposed reductions to the ‘4.8kV CC:
8 Belleville Substation and Circuit Conversion’ project?**

9 A29. I disagree. The Belleville conversion project has investments in both the IRM and
10 base rates and is included in my discussion regarding projects in the IRM above.
11 Per Exhibit A-50 Schedule QQ1, Line 18, the ‘4.8kV CC: Belleville Substation and
12 Circuit Conversion’ project demonstrates completed activities in 2024 and 2025 in
13 the IRM; this project was also included in Exhibit A-12 Schedule B5.4.8. The ramp-
14 rate shown on Line 18, column (I) is consistent with a project entering the
15 construction phase after completing engineering and design work. Witness Shi’s
16 proposed reductions to the Belleville conversion project should be rejected; I
17 address her comments regarding additional requested details at the end of Rebuttal
18 Topic 1.

19

20 **Q30. What does Witness Shi recommend regarding the Company’s ‘4.8kV CC: Ann
21 Arbor AC Network Conversion’ project (#24 in Table 1)?**

22 A30. Witness Shi notes that the Company’s 2023 and 2024 actual expenditures in the
23 instant case come after no previous projections for these capital expenditures¹⁹.

¹⁷ Shi DT, p. 34, Lines 21-26

¹⁸ Shi DT, p. 35, Lines 1-3

¹⁹ Shi DT, p. 35, Lines 14-15

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1 While noting that “Staff supports the conversion,” Witness Shi states there has been
2 “limited planning detail in the record relative to the requested ramp-up” and that
3 “Staff requests clear delineation of engineering, overhead design and construction,
4 and underground design and construction by year;” she goes on to recommend a
5 20% reduction of \$0.7 million to the 2025 projected bridge period and a 20%
6 reduction of \$1.0 million to the 2026 projected test year “unless the Company files
7 a work package plan that ties quantities and unit costs to the requested funding by
8 functional category²⁰.”

9

10 **Q31. How do you respond to Witness Shi’s proposed reductions to the ‘4.8kV CC:**
11 **Ann Arbor AC Network Conversion’ project?**

12 A31. I disagree. The ‘4.8kV CC: Ann Arbor AC Network Conversion’ project has
13 investments in both the rate case and the IRM. The Company also notes that this
14 project was presented in Case No. U-21297 Exhibit A-12 Schedule B5.4, page 10,
15 Line 75. Per Exhibit A-50 Schedule QQ1, Line 19 the ‘4.8kV CC: Ann Arbor AC
16 Network Conversion’ project has investments in the IRM; as previously noted this
17 is one of the projects previously identified for cost recovery through the IRM and
18 was not included in the Case No. U-21534 filing, but is now included in the instant
19 case following the Commission’s directive to remove conversions from the IRM.

20

21 Witness Shi’s proposed reductions to the Ann Arbor AC Network conversion
22 project should be rejected; I address her comments regarding additional detailed
23 information at the end of Rebuttal Topic 1.

24

²⁰ Shi DT, p. 35, Line 18 – p. 36, Line 3

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1 **Q32. What does Witness Shi recommend regarding the Company’s ‘4.8kV CC:**
2 **Hemlock Decommissioning and Circuit Conversion’ project (#26 in Table 1)?**

3 A32. Witness Shi states that the Company has underspent against its projections for the
4 ‘4.8kV CC: Hemlock Decommissioning and Circuit Conversion’ project and
5 recommends a 20% reduction of \$0.3 million from the projected 2025 bridge period
6 and a 20% reduction of \$0.2 million from the projected 2026 test year “due to
7 absence of a detailed scope of work, procurement status, and schedule for both
8 years²¹.”

9

10 **Q33. How do you respond to Witness Shi’s proposed reductions to the ‘4.8kV CC:**
11 **Hemlock Decommissioning and Circuit Conversion’ project?**

12 A33. I disagree. Per Exhibit A-50 Schedule QQ1, Line 20, the ‘4.8kV CC: Hemlock
13 Decommission and Circuit Conversion’ project has expenditures in both the IRM
14 and the base rates and is included in my discussion regarding projects in the IRM
15 above; this project was also included in Exhibit A-12 Schedule B5.4.8. The
16 Company intends to complete all projected 2026 work scope as filed in the instant
17 case. Witness Shi’s proposed reductions to the Hemlock project should be rejected;
18 I address her comments regarding additional detailed information at the end of
19 Rebuttal Topic 1.

²¹ Shi DT, p. 37, Lines 8-17

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1 **Q34. Before addressing the remaining projects recommended for reduction by**
2 **Witness Shi, please summarize your rebuttal regarding projects with**
3 **investment in the IRM.**

4 A34. Witness Shi's proposed reductions to projects with investments in the IRM are
5 based on analysis that incorrectly excludes the IRM investment amounts. When
6 considering only the Company's investments proposed for recovery through base
7 rates, some projects may appear to have unsubstantiated investment ramp rates.
8 However, his perception is due to an incomplete view that excludes recovery
9 through both base rates and the IRM. Therefore, Witness Shi's proposed reductions
10 to the nine projects above should be rejected.

11

12 **Q35. What does Witness Shi recommend regarding the Company's**
13 **'Subtransmission Redesign & Rebuild: Transformer High Side Protection**
14 **Program' (#8 in Table 1)?**

15 A35. Witness Shi states that "Staff supports the program's needs" but says that there is a
16 "lack of justification for the sharp increase in projected costs for 2025 and 2026²²."
17 Witness Shi then lays out a reduction based on the historical average spend from
18 2021-2024, adjusted for inflation, and recommends reduction above those amounts.
19 The proposed reductions are \$4.6 million in 2025 and \$3.0 million in 2026²³.

20

21 **Q36. How do you respond to Witness Shi's recommended reduction for the**
22 **Transformer High Side Protection Program?**

23 A36. I disagree. Besides Witness Shi expressing support for the program, ITC Witness
24 Thompson notes the criticality of this work in his testimony saying that "ITC

²² Shi DT, p. 18, Lines 1-2

²³ Shi DT, p. 18, Lines 5-8

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1 supports DTE's efforts to prioritize deployment of high-side interrupting protection
2 devices throughout its service territory, specifically where it has transformers
3 directly connected to the BES (Bulk Electric System), to improve overall system
4 reliability²⁴."

5
6 The Company has continued to make improvements to its ability to schedule and
7 execute this work and has laid out a sensible schedule for the overall program in
8 Exhibit A-23 Schedule M6, page 21, with execution stretching through 2034.
9 Accepting Witness Shi's proposed reduction will delay the program, and, in turn,
10 impact potential reliability improvements cited by the Company and ITC Witness
11 Thompson. The proposed reduction should be rejected.

12

13 **Q37. What does Witness Shi state regarding the Company's 'Subtransmission**
14 **Redesign & Rebuild: Trunk 3509' project (#9 in Table 1)?**

15 A37. Witness Shi states that "Staff supports the Company's initiative to upgrade Trunk
16 3509 to improve system shutdown capability and operability"²⁵, but noted that "the
17 Company spent less than 15% of its 2025 projection in the first five months without
18 explanation."²⁶ Witness Shi then annualized the spend in the first five months and
19 recommended reduction for the requested amounts in excess of her annualized rate;
20 this totaled \$1.5 million.

²⁴ Thompson DT, p. 3, Lines 20-22

²⁵ Shi DT, p. 19, Line 9

²⁶ Shi DT, p. 19, Line 15

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1 **Q38. How do you respond to Witness Shi's recommended reduction to the Trunk**
2 **3509 project?**

3 A38. I disagree. The Company acknowledges delays early in the project caused by
4 adjacent hazards along the cable pulling route. The pulling route is pre-flighted
5 during the design phase to identify hazards so that they can be remediated and
6 addressed without impacting the overall project schedule. However, it is possible
7 for hazards to emerge after the initial pre-flight.

8

9 The Company is working to address the two remaining hazards now that we are
10 post-summer peak loading and projects to install 2,500 ft of new cable prior to year
11 end, with construction to complete in 2026 in line with the forecasted in-service
12 date. The proposed reduction should be rejected; Company Witness Chiu addresses
13 the use of year-to-date spend for calculating proposed reductions in his rebuttal
14 testimony.

15

16 **Q39. What does Witness Shi state regarding the Company's 'CODI: Alfred**
17 **Substation Expansion' project (#10 in Table 1)?**

18 A39. Witness Shi acknowledges the operational benefits of the project but notes
19 underspend against previous forecasts. She then estimates a full year spend amount
20 for 2025 based on the annualized year-to-date spend through the first five months
21 and inflates that amount for 2026. She recommends reduction of the Company's
22 requested amounts above her estimates, totaling \$2.2 million in 2025 and \$0.4
23 million in 2026²⁷.

24

²⁷ Shi DT, p. 20, Lines 19-24

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1 **Q40. How do you respond to Witness Shi's recommended reduction for the Alfred**
2 **Substation project?**

3 A40. I disagree. The work plan for many projects does not generate the same flat
4 spending amounts each month. Construction activities most often result in the
5 highest spend rates, but must be scheduled based on equipment shutdown schedule,
6 material availability, and other logistical considerations. The Company will work
7 towards the 2025 scope completion and expects to complete the 2026 work scope
8 as well. For these reasons, the proposed reductions should be rejected.

9
10 **Q41. What does Witness Shi state regarding the Company's 'CODI: Targeted**
11 **Network Secondary Cable Replacement' program (#11 in Table 1)?**

12 A41. Witness Shi supports the replacement of network secondary cable, stating "Staff
13 supports the Company replacing the aged cable to reduce the cable failures' cost."²⁸
14 Witness Shi goes on to recommend a reduction of \$1.2 million to the 2025 projected
15 bridge period and \$0.1 million in 2026.

16
17 **Q42. How did Witness Shi calculate her recommended reduction to the 'CODI:**
18 **Targeted Network Secondary Cable Replacement' program?**

19 A42. Witness Shi's recommended reduction to the 'CODI: Targeted Network Secondary
20 Cable Replacement' program is based on a calculation she did for unit cost of
21 installed cable in 2024, which she then inflated for 2025 and 2026. She then
22 multiplied the inflation-adjusted rates by the number of units that the Company
23 forecasted for each year and then recommended reduction for amounts above her
24 calculated value.

²⁸ Shi DT, p. 22, Line 2-3

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1 **Q43. Is Witness Shi’s methodology sound for her recommended reduction to the**
2 **‘CODI: Targeted Network Secondary Cable Replacement’ program?**

3 A43. No. There are two main issues with her methodology. The first is that in general,
4 the nature of below grade underground construction work is highly variable, with
5 many factors to be considered in driving the overall cost of a project. These
6 variables include the condition of the manholes, conduit, and other non-electrical
7 equipment, as well as the presence of adjacent hazards (hazards on adjacent
8 electrical lines) that must be remediated. As a result, costs for individual sections
9 of cable replacement can vary, and Witness Shi’s proposed treatment of using a
10 calculated “not to exceed” cost per unit target based on work in 2024 is not
11 appropriate.

12

13 **Q44. What other issue was found in Witness Shi’s methodology regarding the**
14 **‘CODI: Targeted Network Secondary Cable Replacement’ program?**

15 A44. In her calculation for 2024 costs, Witness Shi excluded the Company’s actual
16 expenditures that were are accounted for in the “Other” cost category stating that
17 they weren’t relevant for unit cost calculation in 2025 and 2026 because the
18 Company’s projections for 2025 and 2026 did not include costs in the “Other”
19 category.²⁹

20

21 Charges in the “Other” category in 2024 included valid expenditures required for
22 the execution of the work in 2024, and if a cost per unit were to be calculated, they
23 must be included. Exhibit A-50 Schedule QQ2 ‘Discovery Responses STDE-20.1a-
24 r’ details the types of valid expenses required for execution of work, including, but

²⁹ Shi DT, p 22, Lines 5-7

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1 not limited to facilities overheads, fleet overheads, stock and procurement
2 overheads, and miscellaneous materials from inventory, among several others.
3 Witness Shi's exclusion of "Other" expenses in her calculation is improper.

4
5 **Q45. What would the unit cost for 2024 actual and the Company's projected 2025**
6 **and 2026 be if the "Other" costs were included?**

7 A45. See Table 4 below for the Company's requested unit costs per foot based on the
8 actual and projected installed feet of cable and capital expenditures shown on page
9 129 of Exhibit A-23 Schedule M6; these unit costs per foot properly include the
10 "Other" accounting category. Table 4 shows that actual unit costs are going down
11 in the projected test year. As noted above in my testimony, costs for individual
12 sections of cable can vary, and the Company took that into consideration when
13 projecting costs for 2025 and 2026 and the implied cost per foot installed unit
14 measure.

15

16 **Table 4 DTE's Implied Secondary Network Cable Unit Cost**

Year	Cost per ft
2024 (actual)	\$361.56
2025 (projected)	\$417.39
2026 (projected)	\$329.67

17

18 **Q46. Should Witness Shi's recommend reduction for the 'CODI: Targeted Network**
19 **Secondary Cable Replacement' program being accepted?**

20 A46. No. The premise of a "not to exceed" cost per unit target is not appropriate for the
21 variable costs of underground cable work. Additionally, Witness Shi's

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1 methodology for calculating the cost per unit improperly omitted costs in the
2 “Other” category. For these reasons, the proposed reduction should be rejected.

3

4 **Q47. What does Witness Shi recommend regarding the Company’s ‘4.8kV CC:**
5 **Grosse Pointe Substation and Circuit Conversion – North’ project (#14 in**
6 **Table 1)?**

7 A47. Witness Shi states that “Staff approves of the project conceptually but notes that
8 the property acquisition costs require clear itemization and accounting treatment”
9 and that “the Company has not supplied a workable breakdown – e.g. manpower,
10 hours, due diligence, appraisals, title, legal, and closing costs – sufficient to support
11 the \$1,500,000 request as ‘labor,’” noting that the 2026 projected expenditure of
12 \$1.5 million was labeled as “Labor” on page 197 of Exhibit A-23 Schedule M6³⁰.
13 She goes on to recommend a 20% reduction of \$0.3 million to the projected test
14 year “pending detailed documentation³¹.”

15

16 **Q48. How do you respond to Witness Shi’s proposed reductions to the ‘4.8kV CC:**
17 **Grosse Pointe Substation and Circuit Conversion – North’ project?**

18 A48. I disagree. The Company notes that the \$1.5 million test year projection was
19 included in the “Labor” line of page 197 of Exhibit A-23 Schedule M6 in error and
20 should have been in the “Other” category; as indicated these expenditures are to
21 purchase property, which is appropriately capitalized under the accounting policy
22 in the Uniform System of Accounts. Witness Shi’s proposed reductions to the
23 Grosse Pointe – North project should be rejected; I address her comments regarding
24 additional detailed information at the end of Rebuttal Topic 1. I also address the

³⁰ Shi DT, p. 25, Lines 4-8

³¹ Shi DT, p. 25, Lines 8-9

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1 details of the “Other” cost category in my discussion of the ‘CODI: Targeted
2 Network Secondary Cable Replacement’ program above.

3

4 **Q49. What does Witness Shi recommend regarding the Company’s ‘4.8kV CC:
5 Melvindale’ project (#15 in Table 1)?**

6 A49. Witness Shi states that “the Company’s supporting materials create confusion in
7 cost classification for property acquisition (e.g., treated as 'labor' in related items,
8 and 'Other' here). Absent a detailed purchase contract and a clear accounting
9 treatment” she goes on to recommend a 20% reduction of \$0.4 million to the 2026
10 projected test year “unless the Company provides the executed or draft purchase
11 agreement(s), itemized transaction costs, and a clear capitalization policy showing
12 the appropriate classification of property acquisition costs³².”

13

14 **Q50. How do you respond to Witness Shi’s proposed reductions to the ‘4.8kV CC:
15 Melvindale’ project?**

16 A50. I disagree. Witness Shi’s recommended reduction to the 4.8kV CC: Melvindale’
17 project is based on the error that the Company noted in the ‘4.8kV CC: Grosse
18 Pointe Substation and Circuit Conversion – North’ project. The Company
19 categorized the projected capital expenditures associated with the property
20 purchase in the Grosse Pointe project and the projected capital expenditures
21 associated with property purchase for the Melvindale project are categorized
22 correctly, the Company follows the accounting policy put forth under the Uniform
23 System of Accounts. Company Witness Uzenski provides rebuttal for this point.

³² Shi DT, p. 27, Lines 1-7

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1 Witness Shi's proposed reductions to the Melvindale project should be rejected; I
2 address her comments regarding additional details at the end of Rebuttal Topic 1.

3

4 **Q51. What does Witness Shi recommend regarding the Company's 'System**
5 **Loading: Jewell' project (#16 in Table 1)?**

6 A51. Witness Shi states that the Company has underspent against its projections for the
7 'System Loading: Jewell' project and notes that the 2026 projected capital
8 expenditures are categorized as "Other" on page 225 of Exhibit A-23 Schedule M6;
9 she goes on to recommend a 20% reduction of \$0.4 million to the 2026 projected
10 test year "unless the Company provides a detailed scope, schedule, and cost
11 breakdown for the 2026 activities along with procurement status for critical path
12 items³³."

13

14 **Q52. How do you respond to Witness Shi's proposed reductions to the 'System**
15 **Loading: Jewell' project?**

16 A52. I disagree. The 2023 and 2024 underspend was due to difficulty in acquiring a
17 property suitable for a new substation; the Company now plans to repurpose the
18 existing Jewell substation property, pending ITC approval, and will be able to
19 proceed with the planned 2026 engineering and design that was described in
20 discovery response STDE-6.16a, provided in Exhibit A-50 Schedule QQ3. The
21 Company intends to complete all projected 2026 work scope as filed in the instant
22 case. Witness Shi's proposed reductions to the 'System Loading: Jewell' project
23 should be rejected; I address her comments regarding additional detailed
24 information at the end of Rebuttal Topic 1. I also address the details of the "Other"

³³ Shi DT, p. 27, Line 20 – p. 28, Line 2

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1 cost category in my discussion of the ‘CODI: Targeted Network Secondary Cable
2 Replacement’ program above.

3

4 **Q53. What does Witness Shi recommend regarding the Company’s**
5 **‘Subtransmission Redesign & Rebuild: Trunk 7105’ project (#17 in Table 1)?**

6 A53. Witness Shi notes that “Staff supports implementing an Emergency Load Control
7 scheme,” but states that the “record lacks a comprehensive budget and explanation
8 supporting the full 2026 request;” she goes on to recommend a 20% reduction of
9 \$0.2 million to the 2026 projected test year “unless the Company provides a
10 complete bill of materials with costs, labor plan, and schedule consistent with the
11 stated milestones³⁴.”

12

13 **Q54. How do you respond to Witness Shi’s proposed reductions to the**
14 **‘Subtransmission Redesign & Rebuild: Trunk 7105’ project?**

15 A54. I disagree. The Company has provided an appropriate level of detail for the Trunk
16 7105 project. In the instant case on pages 238-241 of Exhibit A-23 Schedule M6
17 provides a high-level project scope and milestone schedule. In discovery response
18 STDE-6.18b, provided in Exhibit A-50 Schedule QQ3, I state that “the Company
19 will complete detailed engineering, complete manhole inspections, and conduct
20 detailed design” during the projected test year. Witness Shi’s proposed reductions
21 to the Trunk 7105 project should be rejected; I address her comments regarding
22 additional detailed information at the end of Rebuttal Topic 1.

³⁴ Shi DT, p. 28, Lines 18-23

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1 **Q55. What does Witness Shi recommend regarding the Company's**
2 **'Subtransmission Redesign & Rebuild: Reverse Power Relay Scheme**
3 **Program' (#18 in Table 1)?**

4 A55. While noting that "Staff agrees the program is necessary," Witness Shi states that
5 the "record shows materially lagging execution relative to projections;" she goes
6 on to recommend a 20% reduction of \$0.2 million to both the 2025 projected bridge
7 period and the 2026 projected test year³⁵.

8

9 **Q56. How do you respond to Witness Shi's proposed reductions to the**
10 **'Subtransmission Redesign & Rebuild: Reverse Power Relay Scheme**
11 **Program?'**

12 A56. I disagree. The Company agrees that execution on the 'Subtransmission Redesign
13 & Rebuild: Reverse Power Relay Scheme Program' has been delayed in 2025, but
14 full execution of the 2026 program is expected, therefore Witness Shi's proposed
15 reductions should be rejected.

16

17 **Q57. What does Witness Shi recommend regarding the Company's '4.8kV CC:**
18 **Grosse Pointe Substation and Circuit Conversion' project (#25 in Table 1)?**

19 A57. Witness Shi points out that the "4.8kV CC: Grosse Pointe Substation and Circuit
20 Conversion' project includes 2024 actual expenditures for a property purchase and
21 2024-2029 scope including engineering, pre-conversion, and conversion activities,
22 but then states "the filing lacks a breakdown differentiating engineering, pre-
23 conversion, and conversion activities as well as a definition of what is included in
24 'conversion.' Given the magnitude of the test-year request, more granular planning

³⁵ Shi DT, p. 29, Lines 17-21

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1 detail is needed³⁶.” She goes on to recommend a 20% reduction of \$0.7 million to
2 the 2026 projected test year “unless the Company provides a fully itemized test-
3 year plan and milestones with resource loading³⁷.”
4

5 **Q58. How do you respond to Witness Shi’s proposed reductions to the ‘4.8kV CC:**
6 **Grosse Pointe Substation and Circuit Conversion’ project?**

7 A58. Regarding Witness Shi’s question of what is included in conversion projects, Q&A
8 22 on pages 22-23 of my revised direct testimony describes the various activities
9 done during conversion projects. Also, as provided in discovery response STDE-
10 6.29a, provided in Exhibit A-50 Schedule QQ3, “the Company will conduct
11 detailed substation design, procure material, conduct overhead circuit rebuild
12 detailed design for pre-conversion, and begin construction on overhead circuit
13 rebuilds for pre-conversion in 2026”. When Exhibit A-50 Schedule QQ3 is
14 considered I believe that the Company has provided an appropriate level of detail
15 for the Grosse Pointe conversion project in the instant case filing and therefore
16 Witness Shi’s proposed reductions to the 2026 test year should be are not
17 warranted; I address her comments regarding additional detailed information at the
18 end of Rebuttal Topic 1.
19

20 **Q59. What does Witness Shi recommend regarding the Company’s ‘System**
21 **Loading: Grenada’ project (#27 in Table 1)?**

22 A59. While noting that “Staff supports the upgrades,” Witness Shi states that the
23 Company has underspent against its projections for the ‘System Loading: Grenada’
24 project and recommends a reduction of \$10.3 million to the 2025 projected bridge

³⁶ Shi DT, p. 36, Lines 10-17

³⁷ Shi DT, p. 36, Lines 18-20

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1 period and \$6.2 million to the 2026 projected test year³⁸. She calculates these
2 reductions by annualizing the Company's actual expenditures through May 2025
3 and recommends reduction for expenditures above her calculated 2025 value, then
4 inflates the annualized 2025 amount to 2026 and recommends reduction above her
5 calculated 2026 value.

6

7 **Q60. How do you respond to Witness Shi's proposed reductions to the 'System**
8 **Loading: Grenada' project?**

9 A60. I disagree. The Company provided commentary in Exhibit A-23 Schedule M2 on
10 the 'System Loading: Grenada' project pointing out permit delays beyond the
11 Company's control. The local township permitting has resulted in the completion
12 of additional design to the project which has delayed investment in 2025. The
13 Company agrees that execution has been delayed in 2025, but full execution of the
14 2026 scope of work is expected to be completed in that year, therefore Witness
15 Shi's proposed reductions should be rejected.

16

17 **Q61. Are there any other issues with the methodologies Witness Shi used to**
18 **calculate her proposed reductions?**

19 A61. Yes. There are two issues with Witness Shi's methodology for calculating her
20 proposed reductions. First, for some projects, such as the Trunk 3509 project,
21 Witness Shi annualizes the Company's year-to-date actual expenditures using a
22 linear extrapolation. Company Witness Chiu's rebuttal testimony addresses the
23 Company's position on this methodology.

³⁸ Shi DT, p. 38, Lines 12-16

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1 Second, Witness Shi's analysis for several projects, such as 'CODI: Garfield,' relies
2 on a historic average of actual expenditures for work completed in previous years
3 in strategic capital projects. While work scope year-over-year may be similar in
4 nature for strategic capital projects, the Company notes that work levels may
5 increase or decrease based on many factors including the overall resource plan,
6 equipment shutdown schedules, material availability, and the status of associated
7 corrective maintenance work. Historic averages of strategic capital projects may
8 also include the ramp-down of work scope for phases that are nearing completion
9 and are not indicative of costs associated with subsequent phases of work beginning
10 to ramp up.

11

12 Using the 'CODI: Garfield' projects for example, page 258 of Exhibit A-23
13 Schedule M6 shows the approximate construction schedule with 2020-2025
14 showing detailed engineering and construction of system conduit and netbanks,
15 while 2022-2027 concurrently shows detailed engineering and construction
16 associated with the radial conversion. While these different work scopes may sound
17 similar at a high level because both include engineering, design, and construction,
18 the cost of the prior years' expenditures is not indicative of the costs in the
19 subsequent years. The difference between the two scopes of work is that the 2020-
20 2025 engineering, design and construction is specific to the secondary AC network
21 whereas the 2022-2027 engineering, design and construction is specific to primary
22 cable that services primary customers. These similar sounding tasks require
23 different levels of resources to complete. That difference in resource requirements
24 invalidates Witness Shi's methodology for calculating her proposed reductions.

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1 **Q62. How do you respond to Witness Shi's suggestion to provide a greater level of**
2 **granularity for various projects?**

3 A62. The Company has already provided substantial documentation and evidence
4 supporting its capital expenditures for the Redesign projects. For example, Exhibit
5 A-23 Schedule M6 includes 393 pages of detailed information, outlining project
6 scope, milestones, and planning considerations. This level of detail reflects the
7 Company's commitment to transparency and regulatory compliance.

8
9 In her proposed rate recovery reductions for several projects, Witness Shi asserts
10 that the Company has not provided sufficient evidence to support its capital
11 expenditures. Citing the 'Subtransmission Redesign & Rebuild: Trunk 7105'
12 project, Witness Shi recommends a reduction of 20% of the projected test year cost
13 "unless the Company provides a complete bill of materials with costs, labor, plan,
14 and schedule consistent with the stated milestones³⁹." In another example, citing
15 the '4.8kV CC: Grosse Pointe Substation and Circuit Conversion' project, Witness
16 Shi similarly recommends a reduction of 20% of the projected test year cost because
17 "given the magnitude of the test-year request, more granular planning detail is
18 needed" and she opposes cost recovery "unless the Company provides a fully
19 itemized test-year plan and milestones with resource loading⁴⁰."

20
21 Including the "granular planning detail" that Witness Shi believes is needed, such
22 as "bill of materials with costs, labor, plan, and schedules" for every project would
23 significantly expand the record with matters that shed relatively little light on
24 whether a project is reasonable and prudent. In Distribution Operations alone, DTE

³⁹ Shi DT, p. 28, Lines 21-23

⁴⁰ Shi DT, p. 36. Lines 16-20

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1 Electric executes numerous projects every year – and which “other granular details”
2 might have been considered desirable for the Company to offer into evidence by
3 the dozens of parties and dozens of witnesses in every proceeding is virtually
4 unknowable.

5
6 The Company also notes that it has not previously provided this granular level of
7 detail in electric rate cases for the Commission’s approval of Redesign projects as
8 it has not been considered a prerequisite for regulatory approval. I believe that
9 Witness Shi’s requests for these granular details as a prerequisite for cost recovery
10 should be rejected as impractical and unnecessary.

11

12 Rebuttal Topic 1 Conclusion

13

14 **Q63. What should the Commission find with respect to Staff Witness Shi’s**
15 **recommendations regarding the Company’s Redesign projects?**

16 A63. The Company appreciates Witness Shi’s support for and understanding of the need
17 to complete Infrastructure Redesign & Modernization projects but respectfully
18 disagrees with her recommended reductions. The Commission should find that:

- 19 - The proposed reductions totaling \$58.3 million for the projects included in
20 the IRM should not be accepted in light of the more accurate investment
21 ramp rate analysis I provide above;
22 - Witness Shi’s exclusion of actual expenditures in the “Other” cost category,
23 which includes valid expenditures, in her calculations for proposed
24 reductions is improper;

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- 1 - Witness Shi's use of historic average expenditures in the Company's
2 strategic capital projects to forecast future expenditures is improper; and
3 - Witness Shi's use of linear extrapolation to forecast capital expenditures on
4 strategic capital projects is improper as supported by Company Witness
5 Chiu's rebuttal testimony.

6 -

7 **Rebuttal Topic 2: AG-MN Witness Stephens' recommendations regarding the**
8 **Company's System Loading projects**

9 **Q64. What does Witness Stephens recommend with respect to the Company's**
10 **System Loading projects?**

11 A64. Witness Stephens recommends a reduction of \$45.3 million to the Company's
12 projected test year capital expenditures for System Loading projects,⁴¹ but it
13 appears he misunderstands the purpose of the Company's System Loading projects.
14 Further, Witness Stephens' proposal is flawed and suffers from lack of factual
15 support, as well as demonstrates little consideration for the substantial amount of
16 information provided by the Company in over 330 discovery responses related to
17 these projects alone which demonstrate that the Company's System Loading
18 projects are driven by system overloads, the primary driver for these projects.

19
20 Related to his analysis of the Company's System Loading projects, Witness
21 Stephens also makes other recommendations and statements as summarized below
22 that I will briefly cover in my rebuttal:

- 23 • Witness Stephens recommends that the Commission should require benefit-
24 cost analyses for the Company's System Loading projects citing the

⁴¹ Stephens DT, p. 44, Lines 10-11

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1 Commission's requirement for benefit-cost analyses for new
2 Subtransmission Redesign projects over \$10 million⁴².

3

4 Other statements and recommendations in Witness Stephens' assessment of the
5 Company's System Loading program that are addressed more generally in other
6 Company witness's rebuttal testimonies are as follows:

- 7 • Witness Stephens recommends that the Commission require the Company
8 to implement a circuit-specific load forecasting capability in advance of the
9 Company's next rate case⁴³. Company Witness Leuker's rebuttal testimony
10 in the instant case addresses this recommendation, though it should be noted
11 that Witness Stephens incorrectly asserts that the Liberty Audit in Case No.
12 U-21305 also makes his same recommendation.

13

14 Witness Stephens made several other statements that I address at the end of this
15 section.

16

17 **Q65. How does Witness Stephens address the Company's purpose for the System**
18 **Loading projects?**

19 A65. As noted in the title of this section of his testimony, AG-MN Witness Stephens
20 believes that the Company's System loading program and projects are costly and
21 premature solutions to circuit overloads⁴⁴. He further states that the Company's
22 "System Loading program intends to address violations of the Company's **capacity**
23 **planning guidelines** among distribution substations and circuits⁴⁵."

⁴² Stephens DT, p. 44, Lines 4-7

⁴³ Stephens DT, p. 44, Lines 8-9

⁴⁴ Stephens DT, p. 34, Line 14

⁴⁵ Stephens DT, p. 35, Lines 1-2 (emphasis added).

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1

2 **Q66. How do you respond to Witness Stephens' assertion that System Loading**
3 **projects are intended to address violations of the Company's capacity**
4 **planning guidelines?**

5 A66. I disagree. Witness Stephens refers to the Company's "capacity planning
6 guidelines," specifically the 13.2kV Distribution Design Order ("DDO"), as the
7 basis for his conclusion. The DDO guides the engineer on how to plan and design
8 a circuit – including guidance to plan for 13.2kv circuits to operate at no more than
9 8 MVA, but with equipment rated at 10 MVA under normal conditions and 12
10 MVA in emergency conditions. It is incorrect to suggest that System Loading
11 projects are solely intended to address violations of these guidelines.

12

13 **Q67. What is the actual purpose of the Company's System Loading projects?**

14 A67. As I explain in Q&A 65 of my revised direct testimony (page 75), "System Loading
15 projects are capital investment projects to address system overloads on the
16 distribution system, in order to mitigate overloads, improve reliability and provide
17 new capacity for new and existing customers." These projects are not targeting
18 individual circuits for DDO circuit planning violations but are specific investments
19 to address overloaded substations and substation areas to ensure long-term system
20 performance and customer service.

21

22 **Q68. Can you explain the difference between the Company's rationale for System**
23 **Loading projects and Witness Stephens' apparent misunderstanding of the**
24 **purpose of the System Loading projects?**

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1 A68. Yes. Witness Stephens incorrectly argues that the Company is basing the need for
2 System Loading projects on DDO limits of 8 MVA for 13.2kV circuits and is using
3 the 2016 DDO to justify the creation of unnecessary projects to rebuild its
4 infrastructure⁴⁶. He is arguing that the System Loading projects are not based on
5 system loading conditions, but instead on violations of planning criteria.

6 The Company's System Loading projects, however, are driven by current
7 distribution system issues and address current substation overloads (*i.e.*, substations
8 loaded over their firm rating).

9
10 Additionally, as highlighted by Figure 1 below (also shown as Figure 6 on page 37
11 of my revised direct testimony), there are different levels of overloading conditions.
12 Generally, when a circuit overload takes place, the Company initiates a smaller
13 scale solution such as circuit reconfiguration to transfer load to neighboring circuits
14 or upgrading the limiting element such as a system cable or conductor. Projects in
15 the System Loading category are addressing system or area problems and are not
16 focused on DDO violations or single distribution circuits as implied by Witness
17 Stephens.

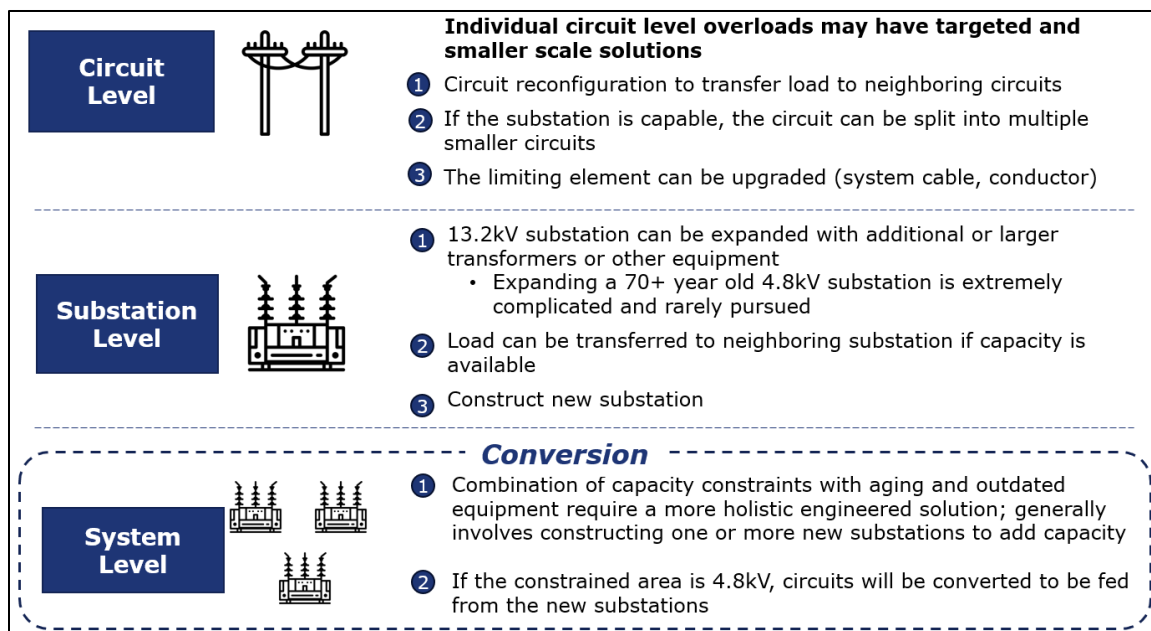
18

⁴⁶ Stephens DT, p. 35, Lines10-16

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1

Figure 1 Levels of Overloading Conditions



2 **Q69. What is a substation firm rating and how does a substations “% of firm”**
3 **illustrate current loading?**

4 A69. As stated in my revised direct testimony on page 77, substation firm rating is the
5 “maximum load the substation can carry under a single contingency condition and
6 is based on the lowest emergency rating of any substation equipment that is required
7 to serve the load.” The firm rating is calculated for each individual substation and
8 its associated equipment. The “% of firm” terminology refers to how much of the
9 firm capacity of the substation is currently being utilized. Numbers at or above
10 100% indicate that the substation is overloaded.

11

12 **Q70. Was the Audit Report supportive of the Company’s plans for System Load**
13 **projects?**

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1 A70. Yes, they were. The Audit Report noted that the “DGP appropriately plans for large
2 investments for load relief at substations” and that “DTE clearly has a significant
3 number of substations whose equipment has well exceeded planning criteria,
4 calling for reinforcement.”⁴⁷
5

6 **Q71. Do any of the 12 System Loading projects recommended for disallowance by**
7 **Witness Stephens use the DDO for 13.2kV circuits as the justification for the**
8 **project?**

9 A71. No. Of the 12 projects cited for disallowance by Witness Stephens, all contain
10 substations that are loaded over their firm rating. This means that it is irrelevant
11 what the circuit DDO is because the substation itself is currently overloaded and
12 efforts must be taken to resolve this issue.

13 In Exhibit A-23, Schedule M6, the company describes the overall purpose of
14 individual projects in a section titled “Purpose and Necessity”. Where DDO
15 violations exist, they are often listed as the proposed project will address the
16 violation during project design. However, DDO violations are not the driver for
17 System Loading projects.
18

19 **Q72. What are the loading conditions of the substations covered by Witness**
20 **Stephens’s proposed disallowances?**

21 A72. See Table 5 below, it contains the loading of the 12 projects identified by Witness
22 Stephens. Eleven of the 12 projects are forecasted to be overloaded in 2025. The
23 exception is Sterling, which has unique circumstances that are covered in following
24 questions.

⁴⁷ Audit Report, Part 2, p. 82-83

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**Table 5 Substation Load Forecast for the 12 Projects with Recommended
Disallowances**

Project Name	Substation	Firm Rating (MVA)	2025 Load Forecast (MVA)	2025 %Firm
Mohican	Cypress			108%
Chesterfield	Chesterfield			99.8%
Cody	Cody			104%
Disco	Disco			110%
Goodison	Goodison			129%
Kings Point	Boyne			110%
Lark/Spruce	Spruce			104%
Otsego/Capac/Shaw	Otsego			126%
	Capac			109%
Port Sanilac	Forester			N/A
	Port Sanilac			N/A
Richmond/Armada	Richmond			100%
	Armada			108%
Spokane/Seneca	Spokane			117%
	Seneca			127%
Sterling	Sterling			84%

Q73. Why don't the substations associated with the Port Sanilac project have a firm rating?

A73. Port Sanilac and Forester substations are single transformer substations, and because an N-1⁴⁸ event results in loss of electric service they do not have a firm rating. Instead substations like these have a Maximum Loadability rating which is generally based on the day-to-day rating of the circuits which they serve.

Forester has a maximum loadability rating of [REDACTED] MVA and based on Table 5 has a loading of [REDACTED] Port Sanilac has a maximum loadability rating of [REDACTED] MVA and is currently loaded at [REDACTED] The [REDACTED] MVA, the difference

⁴⁸ N-1 identifies a single contingency event, where a load serving piece of equipment has failed or is removed from service. The Company designs substations to N-1, meaning that they continue to serve customers when a piece of equipment is out of service.

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1 between [REDACTED] MVA, of capacity is roughly equivalent to a gas station with a
2 convenience store plus a fast-food restaurant.
3

4 **Q74. Does Witness Stephens believe that substations loaded over their firm rating**
5 **is a substantial reason for supporting System Loading projects?**

6 A74. Yes, he does. In fact, Witness Stephens recommends that “When a load growth
7 forecast indicates a substation’s firm capacity rating is likely to be exceeded in the
8 next three to five years, conversion planning should commence”⁴⁹. Given that all
9 12 System Loading projects recommended for disallowance have overloaded
10 substations today (with the exception of Sterling which is discussed below), these
11 projects should all be executed by the Company and approved for recovery in rates.
12

13 **Q75. Why is Sterling substation included in the System Loading program?**

14 A75. Sterling substation load relief is included in the System Loading section of projects
15 due to the unique configuration of the existing substation and the loading
16 constraints in the areas surrounding Sterling.
17

18 As described in Exhibit 23, Schedule M6 on page 386, the switchgear line up at
19 Sterling is a straight bus, across the aisle configuration and that there are no
20 additional positions available to create new circuits. This creates two challenges,
21 the first is the overall single point of failure risk created by all customer load for
22 Sterling flowing through the single switchgear line up. The second is that although
23 the substation itself can handle additional load, no additional circuits can be run
24 from Sterling because of the lack of available positions in the switchgear lineup.

⁴⁹ Stephens DT, p. 61, Lines 8-12

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1 That means all load additions or load growth must be handled by the existing
2 circuits.

3

4 The existing circuits out of Sterling have several loading challenges, and limited
5 opportunities for load transfers. The expansion and reconfiguration of Sterling will
6 provide the method to access capacity at Sterling, provide load relief for existing
7 circuits at Sterling, and provide additional capacity for the area surrounding
8 Sterling.

9

10 **Q76. What are your thoughts concerning Witness Stephens' proposal for**
11 **disallowance on the basis of no load growth on 12 of the Company's System**
12 **Loading projects?**

13 A76. Witness Stephens' conclusions from the data provided through discovery responses
14 is incorrect. He states that "loads have been mostly flat, and in many cases falling,
15 for most of these circuits and substations"⁵⁰. While the Company provided
16 intervenors with the substation information that MNSC requested in discovery, to
17 establish a complete assessment of the need for these System Loading projects,
18 Table 6 below shows the substation loading data highlighting system overloads;
19 Table 6 includes information that MNSC did not request, but is needed to accurately
20 analyze these projects. As can be noted in the table, each of the projects show
21 positive load growth. Since the substations associated with these projects are
22 already over their firm rating, any load growth only further exacerbates the loading
23 problem at the substation. Thus, there is load growth on the 12 projects and Witness
24 Stephens's recommendation should be rejected.

⁵⁰ Stephens DT, p. 39, Lines 3-5

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Table 6 Load Forecast for 12 System Loading Projects Recommended for

Disallowance

Project Name	Substation	2025 Load Forecast (MVA)	2029 Load Forecast (MVA)
Mohican	Cypress		
Chesterfield	Chesterfield		
Cody	Cody		
Disco	Disco		
Goodison	Goodison		
Kings Point	Boyne		
Lark/Spruce	Spruce		
Otsego/Capac/Shaw	Otsego		
	Capac		
Port Sanilac	Forester		
	Port Sanilac		
Richmond/Armada	Richmond		
	Armada		
Spokane/Seneca	Spokane		
	Seneca		
Sterling	Sterling		

Q77. What is your response to Witness Stephens' recommendation regarding benefit-cost analyses for System Loading projects?

A77. In my experience it is not typical utility practice to conduct benefit-cost analyses for capacity-based projects. When equipment is overloaded, there is a higher risk of catastrophic failure. The Company expects that any benefit-cost analysis for System Loading projects to be strongly positive because they are not discretionary – they are essential to maintain safe and reliable service. The notion that the Company would need to do a benefit-cost analysis to evaluate work that is obviously necessary to properly serve customers is not productive. Company Witness Chiu also rebuts this recommendation in his rebuttal testimony.

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1 A recent failure at Jupiter substation (a two-transformer substation) serves to
2 highlight the risks associated with overloaded equipment. On July 27, 2025,
3 Transformer 2 went offline due to an animal intrusion. While investigating the
4 Transformer 2 failure, the responding substation operator conducted an inspection
5 of Transformer 1. The operator reported that load on Transformer 1 was over its
6 day-to-day load limit and rising; the operator later reported the load was
7 approaching the equipment emergency rating, which it ended up surpassing. While
8 operating above its emergency rating, Transformer 1 catastrophically failed. The
9 catastrophic failure of Transformer 1 resulted in the interruption of service to over
10 15,900 customers. Service restoration was conducted through various jumpering
11 steps to adjacent circuits over the course of six hours.

12

13 These types of failures underscore the necessity of proactive asset replacement
14 through the Company's System Loading projects when a system overload is
15 identified. While benefit-cost analyses are valuable tools, their application to
16 System Loading projects is largely inappropriate because these projects are
17 necessary to prevent equipment from being damaged or destroyed.

18

19 **Q78. What additional statements in Witness Stephens' direct testimony do you wish**
20 **to address?**

21 A78. Witness Stephens makes the following statements regarding System Loading
22 projects that I wish to address:

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- 1 • He incorrectly claims that the Company did not provide load growth
- 2 forecasts that he requested⁵¹. He goes on to misinterpret the load growth
- 3 forecasts that were provided in the instant case⁵².
- 4 • He incorrectly asserts that routine and mandatory reliability improvement
- 5 efforts, such as vegetation management and pole and pole top inspections
- 6 and maintenance will reduce service interruptions and reduce the need to
- 7 implement System Loading projects⁵³.
- 8 • He states that the DDO 13.2kV capacity planning standard of 8MW is
- 9 “arbitrary”⁵⁴
- 10 • He incorrectly asserts that justifications for System Loading projects, such
- 11 as historical analysis of service interruption data and safety incident data are
- 12 weak or non-existent⁵⁵.

13

14 **Q79. Did the Company provide load growth forecasts to Witness Stephens in**
15 **discovery?**

16 A79. Yes. Among the over 330 discovery responses submitted to MNSC on the subject
17 of System Loading projects is the Company’s response to MNSCDE-4.2civ.
18 Discovery response MNSCDE-4.2civ and the associated confidential attachment,
19 provided in Exhibit A-50 Schedule QQ4, shows substation firm ratings and historic
20 and forecasted load for the requested substations. It should be noted that the loading
21 information requested by MNSC varied significantly from project to project. For
22 some projects, circuit and substation historical loading were asked for, in others

⁵¹ Stephens DT, p. 40, Line 9-14

⁵² Stephens DT, p. 41, Line 3 – p. 42, Line 4

⁵³ Stephens DT, p. 36, Lines 1-4

⁵⁴ Stephens DT, p. 36, Lines 15-16

⁵⁵ Stephens DT, p. 37, Lines 2-4

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1 relative % of firm rating, and in others the loading on each transformer. Witness
2 Stephens did acknowledge that he secured load history for 15 of the projects⁵⁶,
3 which coincides with the 15 projects that MNSC requested data for in MNSCDE-
4 4. Information that was not requested was not provided.

5

6 Review of the information that was provided shows that substations are over their
7 firm ratings at the current loads, a key fact that Witness Stephens fails to
8 meaningfully consider when evaluating the Company's forecasted load growth.

9

10 **Q80. Will Witness Stephens' suggestion that routine reliability improvement efforts**
11 **reduce the need for System Loading projects?**

12 A80. No. On page 36, lines 1 – 4 of his direct testimony, Witness Stephens states that
13 “routine and mandatory reliability improvement efforts, such as vegetation
14 management, and pole and pole top inspections and maintenance, will reduce
15 service interruptions and, as a result, the need to rely on grid reconfigurations to
16 isolate service interruptions to fewer customers.” Witness Stephens is correct in
17 saying that completion of vegetation management and pole top maintenance work
18 will improve overall reliability. But that work will have no effect on the loading of
19 the substation, and as such the substation would remain over firm.

20

21 **Q81. Is the Company's 13.2kV circuit loading Distribution Design Order (“DDO”)**
22 **selected arbitrarily?**

23 A81. No. Witness Stephens refers to the DDO limit of 8 MVA of load on a 13.2kV
24 circuit as an arbitrary standard that the Company is using to justify projects that

⁵⁶ Stephens DT, p 39, Line 3

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1 address substation overloads⁵⁷. As stated in my response to Q66 above, the DDO
2 is the planning criteria, and it is the basis that an engineer uses to design a particular
3 piece of equipment or portion of the electrical system. In the case of 13.2kV, the
4 DDO guides the engineer to plan for the circuit to operate at 8 MVA but design it
5 with equipment rated for 10 MVA day-to-day, or 12 MVA in an emergency. It
6 provides the basis or standard for sizing all equipment upstream and downstream,
7 including breakers, cable, conductor, and other equipment. The DDO is specific
8 and methodical and was not selected arbitrarily.

9

10 **Q82. Are there other benefits to System Loading projects that Witness Stephens**
11 **confuses for primary project justifications?**

12 A82. Yes, there are. Witness Stephens asserts that “additional justifications for system
13 loading projects, such as historical analysis of service interruption data and safety
14 incident data are weak to non-existent”⁵⁸. In actuality, extensive data was requested
15 by MNSC and provided by the Company through discovery.

16

17 Safety related data requests included historical counts of wire downs and were
18 provided in discovery response MNSCDE-4.4ai, provided in Exhibit A-50
19 Schedule QQ5, which details wire down incidents *for the past five years* in the
20 Company’s Exhibit A-23 Schedule M14.1 Global Prioritization Model (“GPM”).
21 For example, the data in the GPM indicates that there have been an average of 15
22 wire down events per year on the Marlett circuits associated with the ‘System
23 Loading: Brown City’ project. Completion of the Brown City project will

⁵⁷ Stephens DT, p. 36, Lines 15-16

⁵⁸ Stephens DT, p. 37, Lines 2-4

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1 significantly reduce the number of wire downs on the Marlett circuits, improving
2 safety for the public.

3
4 Significant reliability data associated with the projects was also provided to MNSC
5 through discovery. One example is the discovery response to MNSCDE-4.7bii,
6 also provided in Exhibit A-50 Schedule QQ5, in which I highlighted that the
7 capacity issues in the Disco project and the other system loading projects impact
8 reliability by not allowing for fast restoration of outages on adjacent circuits
9 because jumpering or rerouting power flow cannot be done because of the
10 overloads.

11
12 In the Disco Project area there have been 35 outage events over the previous 5 years
13 that affected over 18,200 customers for a total of 18.8 million customer minutes
14 interrupted. Addressing the overloading conditions at Disco would allow future
15 outages like these to be restored significantly faster.

16

17 **Q83. Can you summarize your rebuttal of AG-MN Witness Stephens'**
18 **recommendations and statements regarding the Company's System Loading**
19 **projects?**

20 A83. Yes. The Commission should give little weight to Witness Stephens's testimony
21 recommending disallowances for System Loading projects for the following
22 reasons:

23 • Witness Stephens' recommended disallowance of \$45.3 million for System
24 Loading projects should be disregarded because these projects are not
25 driven by load growth, but by current system overloads, for which the

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1 Company has provided substantial support; any load growth would only
2 exacerbate those existing system overloads.

3 • Witness Stephens is incorrect that the Company's System Loading projects
4 are premature responses to circuit overloads; they are projects to address
5 current system overloads after the Company engages in appropriate
6 consideration of the circumstances and alternatives.

7 • Witness Stephens has incorrectly identified auxiliary benefits of System
8 Loading projects as primary drivers and incorrectly concluded that the
9 Company's System Loading projects are unsupported by the record.

10

11 **Rebuttal Topic 3: AG-MN Witness Stephens' recommendations regarding the**
12 **Company's Conversions program**

13 **Q84. What does Witness Stephens recommend with respect to the Company's**
14 **Conversions program?**

15 A84. Witness Stephens recommends disallowance of the Company's projected test year
16 capital expenditures in the amount of \$20.7 million for the Pontiac 8.3kV overhead
17 and underground circuit conversions⁵⁹.

18

19 He also recommends that the Commission should "prohibit circuit and substation
20 conversions absent bona-fide load forecasts indicating loads will exceed 90% of
21 equipment ratings in the next three to five years⁶⁰."

22

23 Witness Stephens also makes several statements related to conversions that I
24 disagree with, which I briefly address at the end of this section.

⁵⁹ Stephens DT, p. 66, Lines 11-12

⁶⁰ Stephens DT, p. 66, Lines 8-10

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1 **Q85. On what basis does Witness Stephens’ propose disallowance for the**
2 **Company’s projected test year capital expenditures in the Company’s**
3 **Conversions programs?**

4 A85. In one example, Witness Stephens claims that if the Commission is looking “for
5 low-risk ways to defer capital spending,” cutting the Company’s 8.3kV overhead
6 and underground conversions “represents a reasonable opportunity to do so⁶¹.”
7 However, he does not support that assertion with independent analysis and
8 recommends no longer funding the Company’s 8.3kV Pontiac Conversion program
9 based on his conclusion that doing so is “low-risk” which disregards important
10 reasons supporting the need to convert the Pontiac 8.3kV system.

11
12 Witness Stephens appears to heavily, if not solely, rely upon the conclusions in the
13 Audit Report with respect to his recommendation concerning the Pontiac 8.3kV
14 system. (Stephens Direct Testimony pp. 65-66) I detail the Company’s
15 disagreement with the conclusions of the Audit Report on the Pontiac 8.3kV system
16 on pages 72-74, of my revised direct testimony. In summary, there are several
17 significant challenges on the Pontiac 8.3kV system in addition to increasing load,
18 including but not limited to its unique voltage, aged equipment, lack of spare parts,
19 and limited contingency options.

20

21 **Q86. How do you respond to Witness Stephens’ conclusion that a reduction in**
22 **funding of the Pontiac 8.3kV Conversion program is “low risk?”**

23 A86. As I have described in my revised direct testimony on pages 69 – 70, “8.3kV
24 circuits can only be restored or tied to other 8.3kV circuits whereas the surrounding

⁶¹ Stephens DT, p. 65, Line 20 – p. 66, Line 4

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1 area is 13.2kV. This results in high risk for stranded load in the event of an 8.3kV
2 outage event.” I go on to detail additional operational challenges with Pontiac’s
3 8.3kV system, including its aging infrastructure, and failing and obsolete
4 equipment. I also detail an example of an emergent failure on August 19, 2024 at
5 the Rapid Street Substation which affected 1,156 customers, with some of those
6 customers remaining without power for up to 12 hours.

7 **Q87. Have there been any recent occurrences that highlight the ways in which**
8 **Witness Stephens’ views about the risk associated with Pontiac’s 8.3kV system**
9 **are inaccurate?**

10 A87. Yes. On July 24, 2025, the Bartlett Substation experienced a significant failure
11 involving its lone substation transformer. As a result, over 3,100 customers were
12 interrupted. Upon investigation, it was determined that the transformer bushing
13 was damaged and required replacement. To expedite restoration, field crews
14 repurposed bushings from a spare transformer with a different voltage. During the
15 interim, generators and portable ISO units were deployed to restore electric service.
16 The outage extended over 13 hours. It should be noted that 58% of the customers
17 served by Pontiac’s 8.3kV system are in EJ census tracts.

18
19 The bushings had signs of arc flash on them, which can be an indication of an
20 internal failure of the transformer. In this case the transformer tested OK and was
21 returned to service. Had the transformer failed, customers would have been out of
22 service for multiple days until a contingency plan could be developed and
23 implemented, because 8.3kV spare parts are not available and load cannot be
24 jumpered to adjacent 13.2kV circuits.

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1 Citing this recent example and the information provided in my revised direct
2 testimony, Witness Stephens' recommended disallowance of capital expenditures
3 on the Pontiac 8.3kV Conversion program is not "low-risk" and should be
4 disregarded by the Commission.

5 **Q88. Witness Stephens also requests the Commission prohibit circuit and**
6 **substation conversions absent "bona-fide load forecasts indicating loads will**
7 **exceed 90% of equipment ratings in the next three to five years." (Stephens**
8 **Direct Testimony p. 66) Should the Company only initiate conversions projects**
9 **when load is forecasted to exceed 90% of equipment ratings, as Witness**
10 **Stephens recommends?**

11 A88. No. This is a very impractical idea and conflicts significantly with good utility
12 planning practice. The Audit Report noted that "the Company's planning criteria
13 use 80% of firm capacity rating as a criterion for reinforcement. We found that
14 level, which accommodates needs for load transfers when required, consistent with
15 our experience."⁶²

16
17 Exhibit A-50 Schedule QQ6 shows a hypothetical substation illustrating the
18 problem with Witness Stephens grid planning recommendation. The hypothetical
19 substation has two equally sized transformers. If Witness Stephens
20 recommendation were followed, each transformer would be loaded to 90% of its
21 Day-to-Day Rating, resulting in the Hypothetical Substation being loaded at 150%
22 of its Firm Rating before any conversion work could commence. As noted in the
23 Audit Report "DTE's planning for 4.8kV conversions limits them to cases where

⁶² Liberty Audit, part 2 page 78

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1 capacity limits apply, which is sound.”⁶³ Those capacity limits are generally
2 associated with loading of substations at or near 100% of Firm Rating. Increasing
3 that by 50% will be extremely detrimental to the customers served in those areas.
4 The recommendation should be ignored.

5 **Q89. Are there other claims by Witness Stephens that should be addressed?**

6 A89. Yes, Table 7 below summarizes Witness Stephens’s additional claims and my
7 response explaining why those claims should be rejected.

8

9 **Table 7 Conversions Programs Rebuttal Points to Witness Stephens**

Witness Stephens’ Claim	Rebuttal
“DTE should not rush to complete all circuit conversions by 2040 when circuit-specific load growth forecasts would likely indicate that only a subset of 4.8kV circuits must be converted by 2040.” (Page 62, Lines 3 – 5)	The Company is not rushing to complete all circuit conversions. Per the Audit Report recommendation, the Company will continue to plan and execute all proposed 4.8kV conversion projects for the next 5 years since all are driven by capacity needs. Conversion projects outside of the current 5-year window will be proposed if needs are driven by supporting benefit cost analysis including capacity needs.

⁶³ Liberty Audit, part 2, page 85

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Witness Stephens' Claim	Rebuttal
“Reliability improvement is not a reasonable justification because data the Company provided in discovery in U-21297 shows the reliability of 13.2kV circuits (as measured by system average interruption duration without major event days) was worse during 2018-2022 (124 minutes) than the reliability of 4.8kV circuits over the same time period (97 minutes). DTE should be required to document, on a project-level basis, reliability improvements resulting from conversion.” (Page 62, Line 13 – Page 63, Line 2)	Witness Stephens made this same argument in Case No. U-21534. The Company’s position on this remains the same, as summarized below: - Average projected reliability benefits are actually significant (90%), however, beyond the reliability benefits, conversions provide an overall comprehensive solution with benefits to safety, loadability/capacity, and operability - Simple comparison of 4.8kV vs. 13.2kV systems does not fully capture conversion project benefits because the Company is converting some of the worst-performing 4.8kV circuits to 13.2kV circuits built to current construction standards

1

2 **Q90. Can you summarize your rebuttal of AG-MN Witness Stephens’**
3 **recommendations and statements regarding the Company’s Conversion**
4 **programs?**

5 A90. Yes.

- 6 • Witness Stephens’ recommended disallowance of \$20.7 million for the
7 Pontiac 8.3kV overhead and underground conversion projects should be
8 disregarded because reducing funding to these conversions is not “low-risk”
9 as Witness Stephens claims; recent failures on this system highlights the
10 importance of proactively addressing these risks.
- 11 • Witness Stephens’ recommendation to prohibit conversions until forecasted
12 loads exceed 90% of equipment ratings in the next three to five years should
13 be disregarded because his recommendation would result in substations
14 being loaded up to 150% of their firm capacity rating, which is well beyond

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1 the Company's substation planning criteria that the Audit Report found
2 sound and consistent with the auditor's experience.

3 • Additional rebuttal to Witness Stephens on Conversions can be found in
4 Table 7 above.

5

6 **Rebuttal Topic 4: AG-MN Witness Stephens' and ABATE Witness Fitzhenry's**
7 **recommendations regarding the Company's Strategic Undergrounding Program**

8 **Q91. What recommendations are made by AG-MN Witness Stephens and ABATE**
9 **Witness Fitzhenry in the instant case regarding the strategic undergrounding**
10 **("SUG") pilot program?**

11 A91. AG-MN Witness Stephens recommends the disallowance of the Company's
12 projected test year capital expenditures of \$14.0 million for the entire strategic
13 undergrounding pilot program. ABATE Witness Fitzhenry recommends a
14 reduction of \$11.6 million to the Company's projected test year capital
15 expenditures on the Spruce undergrounding pilot⁶⁴.

16

17 **Q92. What does Witness Stephens claim with regard to the Company's strategic**
18 **undergrounding pilot program?**

19 A92. Witness Stephens believes that SUG is "throwing good money after bad"⁶⁵.

20

21 Citing a Lawrence Berkley National Laboratory report, Witness Stephens asserts
22 that undergrounding overhead lines is not cost-effective, and the footnote states that
23 it shows a ratio of \$0.30 in benefits for every \$1 spent⁶⁶.

⁶⁴ Fitzhenry DT, p 17, Line 6

⁶⁵ Stephens DT, p. 66, Line 14

⁶⁶ Stephens DT, p. 67, Lines 6-10

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1 He goes on to state that the Case No. U-21305 Audit Report recommended avoiding
2 commitments to an undergrounding program until the results from carefully
3 planned pilots are available and claims that from his perspective, such results are
4 already available⁶⁷.

5

6 **Q93. What did the Commission conclude in their Order regarding the Audit**
7 **observations and recommendations for Undergrounding pilots?**

8 A93. In the Case No. U-21305 Order dated June 12, 2025, the Commission noted that
9 they agree “that the company should clearly define the criteria it uses to determine
10 the viability of undergrounding in various contexts, including a clear BCA that
11 compares undergrounding with leaving the lines overhead”, and further reiterated
12 their comments from the previous rate case when they noted the Commission
13 “continues to see value in undergrounding for targeted areas where undergrounding
14 is shown to be the best option but continues to have significant and ongoing
15 concerns over DTE Electric’s support for its SUG [strategic undergrounding]
16 pilots,” and further stated “that it “strongly encourages the company to better
17 develop the business case for undergrounding—both at the pilot phase and for
18 scaled deployment—and to continue to develop processes, gain efficiencies, and
19 find synergies where possible to lower costs and to incorporate updated costs and
20 better quantified benefits into its BCA/BCR [benefit-cost ratio] to support future
21 cost recovery, considering projects on a full-scale basis⁶⁸.”

⁶⁷ Stephens DT, p. 67, Lines 14-16

⁶⁸ U-21305 – Commission Order, June 12, 2025, pp. 34-35

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1 **Q94. How has the Company responded to the Commission’s requests regarding**
2 **undergrounding pilots in the Case No. U-21305 Audit and the Case No. U-**
3 **21534 rate case Orders?**

4 A94. In the Case No. U-21534 Order dated January 23, 2025, pages 141-142, the
5 Commission noted its interest in comprehensive benefit-cost analysis (“BCA”) that
6 includes a documentation of benefits and accounts for the costs of alternatives such
7 as overhead rebuilds and pole and pole top maintenance and modernization
8 (“PTMM”) and for the Company to “continue to develop processes, gain
9 efficiencies, and find synergies where possible to lower costs and to incorporate
10 updated costs and better quantified benefits into its BCA/BCR (benefit-to-cost
11 ratio) to support future cost recovery.” The Commission further reiterated this in
12 the Case No. U-21305 Order dated June 12, 2025, pages 33-35, by agreeing with
13 the Audit Report’s recommendation that the Company should define the viability
14 of undergrounding in various contexts, including a clear BCA that compares
15 undergrounding with leaving the lines overhead.

16
17 The Company has worked to meet the Commission’s interest in a more
18 comprehensive BCA. As stated in Company Witness Chiu’s direct testimony, the
19 Company engaged 1898 & Co. (“1898”), an engineering consultancy with
20 extensive experience performing reliability investment BCAs in many regulatory
21 jurisdictions, to model and quantify additional BCAs for the Company’s strategic
22 undergrounding pilots filed in the instant case. Company Witness De Stigter direct
23 testimony details the methodology utilized by 1898 to evaluate the undergrounding
24 pilots against the overhead rebuild and PTMM alternatives and provides BCRs for
25 these alternatives.

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1 Additionally, the Company paused the development of additional pilots during
2 2025 to continue the development of the BCA tool with 1898 to provide a measure
3 of the net benefits of undergrounding projects.

4
5 Lastly, the Company has finalized scope for the two pilots in the instant case, Attica
6 in a rural environment and Spruce in a suburban environment. These two new
7 environments are different from the previous pilots which explored front-lot and
8 rear-lot undergrounding. By building on the learnings from the two previous pilots
9 and the two pilots in the instant case, the Company will be able to gain experience
10 and develop synergies that will further enhance the BCA framework for evaluating
11 undergrounding projects.

12
13 **Q95. Why did the Company start the underground pilot program?**

14 A95. Per Case No. U-20169, the Commission asked the Company to explore pilot
15 projects to eliminate 4.8kV ungrounded delta rear-lot overhead infrastructure and
16 its associated hazards⁶⁹. With the focus on reducing the safety hazard of a downed
17 conductor of a rear-lot 4.8kV ungrounded delta circuit, the Company initiated the
18 first pilot on Appoline DC1346 (Appoline), followed by its second pilot to study
19 the front lot undergrounding design alternative on STLUS DC116 in the Buffalo-
20 Charles neighborhood, as stated on page 126 of my revised direct testimony.

21
22 **Q96. Why is the Company interested in continuing to underground circuits?**

⁶⁹ Commission Order in Case No. U-20169, dated January 18, 2019, p. 4

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1 A96. The Company believes that undergrounding brings a set of unique benefits and is
2 of high interest to our customers and other stakeholders. Undergrounding is the
3 only investment option that fully eliminates the safety risk associated with downed
4 wires and structures. Undergrounding provides the highest overall benefit in
5 reducing emergent reactive costs and customer outages. Undergrounding is the
6 most resilient option for severe weather-related events. Due to these advantages of
7 undergrounding, the Company believes that it needs to conduct additional pilots to
8 continue to learn and focus on reducing implementation costs to increase the overall
9 benefit-to-cost ratio. Learnings from these projects will be used to refine the current
10 benefit cost models to help identify segments of overhead infrastructure that are
11 good candidates for undergrounding. Furthermore, this approach will allow the
12 Company to develop a more cost competitive undergrounding program.

13

14 **Q97. Was Witness Stephens drawing the right conclusion from the LBNL report**
15 **when he said that “available research conducted in a hurricane state (Texas)**
16 **confirms” that undergrounding overhead lines is not cost effective?**

17 A97. No. Upon a quick glance at the introduction to the LBNL report, it is noted that
18 “The purpose of this study is to expand on research by Larsen et al. (2015) by
19 systematically evaluating a policy that requires investor-owned utilities (IOUs) to
20 bury all existing and future transmission and distribution lines underground”⁷⁰ – the
21 study was evaluating the undergrounding of the entire state of Texas’ electrical
22 system, including both distribution and transmission lines.

⁷⁰ Larsen P., *A Method to Estimate the Costs and Benefits of Undergrounding Electricity Transmission and Distribution Lines*. Lawrence Berkeley National Laboratory report LBNL-1006394, p. 4. Accessed September 8, 2025, available at https://eta-publications.lbl.gov/sites/default/files/lbnl-1006394_pre-publication.pdf

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1 In the conclusions of the report, LBNL noted that mandating the undergrounding
2 of the entire electric system of Texas had a benefit cost ratio of 0.3, as Witness
3 Stephens indicated. It also stated that “a subsequent configuration of the model
4 found that a policy specifically targeting urban areas could be cost-effective if a
5 number of key criteria are met.”⁷¹ This notion of targeting specific areas of the
6 grid, aligns well with the Commission’s comments cited above in Q&A 93.

7 **Q98. How does the Company respond to Witness Stephens’ summarization of the**
8 **Strategic Undergrounding pilot projects?**

9 A98. The Company agrees, in part. On a high level, the Company agrees that
10 undergrounding of existing infrastructure is costly. However, Witness Stephens
11 does not include the key point that the Appoline and Buffalo-Charles projects were
12 pilots that the Company was able to learn from and the Spruce and Attica pilots
13 will offer new learnings in different environments. This approach allows the
14 Company to develop processes and gain efficiencies on early, smaller projects to
15 reduce implementation cost before larger-scale undergrounding is rolled out as a
16 broader program. These pilot projects also allow the Company to understand
17 potential cost efficiencies that could be achieved by jointly working with
18 municipalities or other utilities. Using this measured approach, the Company can
19 determine when and where this design option can be utilized most effectively.

20

21 **Q99. How are the strategic undergrounding pilots in the instant case different than**
22 **previous undergrounding pilots?**

⁷¹ *Ibid. at 42*

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1 A99. As stated earlier, the Company previously completed pilots to study rear-lot and
2 front-lot undergrounding. As stated on page 128 of my revised direct testimony, the
3 Attica pilot is being developed to study a rural area while the Spruce pilot is to
4 study a suburban area with coordination of existing city infrastructure work.
5

6 **Q100. How does the Company respond to Witness Stephens' recommendation to**
7 **disallow the full amount for the Strategic Undergrounding Pilot program?**

8 A100. The Company disagrees. The Company believes that undergrounding brings a set
9 of unique benefits to our customers. Undergrounding is an alternative to traditional
10 overhead infrastructure design, one that eliminates the associated safety risk
11 associated with downed conductor and other overhead equipment. Undergrounding
12 provides the benefit of reducing emergent reactive costs and is the most resilient
13 option for severe weather-related events. Due to these benefits of undergrounding,
14 the Company's Spruce and Attica pilots are being developed in order to refine its
15 process and continue to focus on reducing implementation costs. The Company
16 recommends that Witness Stephens' proposed disallowance of the entire strategic
17 undergrounding program be disregarded.
18

19 **Q101. What are ABATE Witness Fitzhenry's comments regarding the Company's**
20 **Spruce undergrounding pilot?**

21 A101. Witness Fitzhenry states that the Spruce undergrounding pilot is not a cost-effective
22 investment for the Company due to the benefits-to-cost ratio of 0.69. He goes on to
23 state that the Company should wait to identify a location that will produce
24 undergrounding benefits that exceed the cost⁷².

⁷² Fitzhenry DT, p. 16, Lines 17-21

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1 **Q102. How do you respond to Witness Fitzhenry’s recommendation that the Spruce**
2 **undergrounding pilot should be disallowed based solely on its benefits-to-cost**
3 **ratio?**

4 A102. I disagree. Witness Fitzhenry acknowledges that the timing of the Spruce
5 undergrounding pilot is coordinated with the City of Ann Arbor’s plan to replace
6 roads in the area, creating a synergy that would allow the Company to avoid costs
7 of breaking down and restoring the roadway⁷³. Despite the estimated benefits-to-
8 cost ratio, this pilot is a unique opportunity to learn from municipal infrastructure
9 coordination with strategic undergrounding in an area that the Company was
10 already going to rebuild as part of the ISO Conversion Program, as stated on page
11 130 of my revised direct testimony. It is also an example of the Company working
12 cooperatively with the City of Ann Arbor. In Case No. U-21534 the Commission
13 explained that “DTE Electric should act to coordinate as much as feasible with local
14 governments and other utilities which will result in cost savings and a lower level
15 of utility disruption for its customers.” (Case No. U-21534 Order dated January 23,
16 2025, p. 458) Witness Fitzhenry’s recommended disallowance of the Spruce
17 undergrounding pilot should be disregarded.

18

19 **Rebuttal Topic 5: Staff Witness Evans’, AG-MN Witness Stephens’, and CEO**
20 **Witness Volkmann’s recommendations regarding the Company’s IRM level of**
21 **investments in the Subtransmission Redesign & Rebuild program**

22 **Q103. Can you briefly describe the role the subtransmission system provides in**
23 **supporting the reliable and stable operation of the grid?**

⁷³ Fitzhenry DT, p. 16, Lines 8-14

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1 A103. The high voltage subtransmission system is an interconnected web that distributes
2 subtransmission level voltage across the service territory to stations, a critical link
3 between the external transmission system (owned by the unaffiliated International
4 Transmission Company (“ITC”)) and the Company’s distribution system. The
5 equipment at these stations steps down the voltage to distribution levels to serve
6 customers. The subtransmission system, operated at the voltages of 24kV, 40kV,
7 and 120kV, provides a vital service as each subtransmission circuit serves one or
8 more distribution substations and is instrumental in providing pathways for power
9 flow and grid flexibility. Failures on this system can affect anywhere from 1 to
10 14,600 customers.

11

12 **Q104. Can you briefly describe the importance of maintaining Subtransmission**
13 **Redesign & Rebuild investments in the IRM?**

14 A104. As previously described, the Company’s subtransmission system is critical to
15 maintaining pathways for power flow and grid flexibility between transmission-
16 level and distribution-level voltages. As stated in Q&A 79 of my revised direct
17 testimony, approximately 16% of the subtransmission circuits (~27% of the
18 Company’s circuit line miles) are in violation of the Company’s planning criteria,
19 per the Company’s 2023 annual subtransmission system analysis. The overall
20 Subtransmission Redesign & Rebuild program is focused on improving grid
21 reliability by installing new equipment, as well as rebuilding both the overhead and
22 underground portions of the subtransmission system. As I explain later in this
23 section of my rebuttal testimony, the Company has a substantial pipeline of
24 Subtransmission projects in development. Continued investment recovery of these
25 projects through the IRM will allow the Company to continue on the important

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1 work either currently underway or in development in its Subtransmission Redesign
2 & Rebuild program.

3

4 **Q105. What recommendations are made by Staff Witness Evans, CEO Witness**
5 **Volkman, and AG-MN Witness Stephens in the instant case regarding the**
6 **level of IRM investments in the Subtransmission Redesign & Rebuild**
7 **program?**

8 A105. Staff Witness Evans recommends keeping the previously approved 2026 IRM
9 investment levels for the Subtransmission Redesign & Rebuild
10 (“Subtransmission”) program the same and does not support the alternative 2026
11 IRM investment levels proposed in Table 4, pages 27 – 28 of Company Witness
12 Willis’ direct testimony⁷⁴. Witness Evans also recommends approving the three-
13 year IRM extension of 2027-2029, but at the alternate proposed levels shown in
14 Table 3, pages 25-26 of Company Witness Willis’ direct testimony for
15 Subtransmission projects⁷⁵.

16

17 CEO Witness Volkman recommends removing Subtransmission projects from the
18 Company’s proposed three-year IRM extension of 2027-2029⁷⁶.

19 AG-MN Witness Stephens recommends rejecting the Company’s proposed
20 alternative 2026 IRM investment levels for Subtransmission projects⁷⁷. Witness

21 Stephens also recommends rejecting the inclusion of Subtransmission projects in
22 the Company’s proposed three-year IRM extension of 2027-2029⁷⁸. It should be

⁷⁴ Evans DT, p. 10, Lines 2-5

⁷⁵ Evans DT, p. 11, Lines 1-6

⁷⁶ Volkman DT, p. 26, Lines 20-22

⁷⁷ Stephens DT, p. 34, Lines 10-13

⁷⁸ Stephens DT, p. 34, Lines 3-5

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1 noted that Witness Stephens incorrectly identifies the proposed 2027-2029
2 investment amount for Subtransmission projects in the IRM as \$323.5 million,
3 which is actually the in-servicing amount. The Company proposes to include \$340
4 million in Subtransmission project investments in the three-year IRM extension of
5 2027-2029. Witness Stephens also makes several incorrect statements in his direct
6 testimony regarding Subtransmission projects which I will also address.

7

8 **Q106. What does Staff Witness Evans state regarding Subtransmission projects in**
9 **the Company's proposed 2026 alternative investment amount and the**
10 **proposed three-year 2027-2029 extension of the IRM?**

11 A106. Regarding the Company's proposed 2026 alternative investment amount, Witness
12 Evans recommends keeping Subtransmission investments at the previously
13 approved level because he believes the Company needs to provide a realistic and
14 detailed actionable plan per the Order in Case No. U-21305 filed on June 12, 2025.
15 He goes on to cite this same reason for supporting the Company's proposed
16 alternative 2027-2029 investment amounts for Subtransmission projects in the IRM
17 as opposed to the full proposed amounts.

18 **Q107. How do you respond to Staff Witness Evans' recommendations regarding the**
19 **Company's proposed Subtransmission investments in the IRM?**

20 A107. I agree, in part. While the Company is appreciative of Witness Evans' support for
21 the continuation of Subtransmission investments in the IRM, the Company believes
22 that both the alternative 2026 investment levels and the full proposed 2027-2029
23 investment levels should be approved.

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1 In Case No. U-21534, the Commission stated that it “is persuaded that results from
2 the extensive audit conducted in Case No. U-21305 should inform not only the
3 Company’s overall DGP and capital expenditures, but the programs designated for
4 IRM treatment⁷⁹.” Citing Witness Evans’ support for continuing Subtransmission
5 investments in 2027-2029, the Subtransmission Redesign & Rebuild program is
6 appropriate for IRM treatment.

7

8 Additionally, the Company plans to provide a realistic and actionable plan
9 addressing its Subtransmission Redesign & Rebuild program in its next DSP filing
10 in 2026, as directed by the June 12, 2025 Order but also believes it is important to
11 continue its progress in the program through continuing investments under the IRM
12 in the meantime.

13

14 **Q108. What does CEO Witness Volkmann state regarding Subtransmission projects**
15 **in the Company’s proposed three-year 2027-2029 extension of the IRM?**

16 A108. Witness Volkmann states that the Company has not developed a benefit-cost-
17 analysis (“BCA”) framework for all Subtransmission projects over \$10 million as
18 directed by the Commission in Case No. U-21534⁸⁰. He also acknowledges the
19 statement on pages 103-104 of my revised direct testimony that the Company plans
20 to complete the BCA framework to evaluate new subtransmission projects before
21 the next rate case filing and will apply the framework to all new Subtransmission
22 projects over \$10 million.

⁷⁹ U-21534 – Commission Order, January 23, 2025, p. 302

⁸⁰ Volkmann DT, p. 26, Lines 7-22

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1 **Q109. How do you respond to CEO Witness Volkmann’s recommendations**
2 **regarding the Company’s proposed Subtransmission investments in the IRM?**

3 A109. I agree, in part. I agree with Witness Volkmann that all new Subtransmission
4 projects over \$10 million should have a BCA conducted; however I do not agree
5 that the Subtransmission investments should be excluded from the proposed 2027-
6 2029 IRM extension.

7

8 As stated in discovery responses CEODE-1.3a and MNSCDE-3.30c and the
9 attachment ‘U-21860 CEODE-1.3a Subtransmission Project Pool’, provided in
10 Exhibit A-50 Schedule QQ7, the Company has a substantial pipeline of
11 Subtransmission projects with forecasted 2027 & beyond expenditures of
12 approximately \$640 million, much greater than the proposed \$340 million
13 investment amount in the proposed 2027-2029 IRM extension. These details will
14 be evaluated before deciding which projects shall be included in the annual IRM
15 Plan, as directed by the Commission in Case No. U-21297⁸¹.

16 The Company will utilize the forthcoming BCA framework to analyze the projects
17 in the pipeline. The Company believes that it is reasonable to extend the proposed
18 IRM extension at the full amount for Subtransmission.

⁸¹ Case No. U-21297 Order dated December 1, 2023, p. 286. “The filing of the IRM Investment Plan at least four months prior to the start of each plan year will allow for a more meaningful review by both the Staff and other interested stakeholders. Further, the submission of the plan to all intervening parties, along with providing a forum for interested parties to raise concerns, will allow for additional collaboration and input into the proposed investments.”

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1 **Q110. What does AG-MN Witness Stephens state regarding Subtransmission**
2 **projects in the Company’s proposed 2026 alternative investment amount and**
3 **the proposed three-year 2027-2029 extension of the IRM?**

4 A110. Witness Stephens incorrectly claims that the Company “provides no information in
5 support of” the Subtransmission investment amounts proposed in the three-year
6 extension of the IRM⁸². He offers no direct support for his recommendation to
7 decline the proposed alternate investment levels for 2026.

8

9 Witness Stephens also makes several statements that are not correct which I briefly
10 address at the end of this section.

11

12 **Q111. What information did the Company provide to Witness Stephens in support**
13 **of the Company’s Subtransmission investment levels proposed in the instant**
14 **case?**

15 A111. In discovery response MNSCDE-3.30a, also provided in Exhibit A-50 Schedule
16 QQ7, the Company pointed Witness Stephens to the subtransmission project pool
17 provided in the Exhibit A-50 Schedule QQ7 attachment ‘U-21860 CEODE-1.3a
18 Subtransmission Project Pool’ to highlight the number of projects in the pipeline
19 that can potentially be included in a future IRM. In that discovery response the
20 Company further explained that per the Commission’s Order in Case No. U-21297,
21 the Company would identify and describe the projects to be completed no later than
22 August 31, 2026 for the proposed 2027 IRM, no later than August 31, 2027 for the
23 proposed 2028 IRM, and no later than August 31, 2028 for the proposed 2029 IRM.

⁸² Stephens DT, p. 33, Lines 19-21

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1 The Company notes that the list of projects currently in the pipeline provided in
2 Exhibit A-50 Schedule QQ7 included drivers and high-level scope for each project.
3 The Company has provided reasonable information to support its proposed
4 Subtransmission investment levels in the IRM and because Witness Stephens'
5 recommendations ignored that information those recommendations should be
6 disregarded.

7

8 **Q112. Are there other claims by Witness Stephens regarding Subtransmission**
9 **projects that you would like to address?**

10 A112. Yes, Table 8 below summarizes Witness Stephens's claims and my rebuttal of those
11 claims.

12

13 **Table 8 Subtransmission Redesign & Rebuild Rebuttal Points to Witness**
14 **Stephens**

Witness Stephens' Claim	Rebuttal
"Because customer service interruptions from subtransmission equipment outages represent such a small proportion of time DTE customers spend without power, and because subtransmission projects are so costly, capital spending on the subtransmission system is unlikely to represent a cost-effective approach to improving DTE reliability." (Page 26, Lines 10-14)	This statement does not appropriately consider the condition of the subtransmission system. The Company projects identified based on reliability as the main driver address significant reliability issues, such as Tie 4105 detailed in Q&A 88 of my revised direct testimony.

Witness Stephens' Claim	Rebuttal
Using the example of the new pole top construction standard of fiberglass crossarms being installed; a defective wooden crossarm is identified during inspections instead of broadly replacing all wooden crossarms, Witness Stephens states: "This example applies exactly to subtransmission construction standards, and as a result, rebuilding subtransmission infrastructure that is currently operating safely and reliably just to meet newer construction standards is not appropriate. All utilities continuously update their construction standards as new technologies come along. In my experience, changes in construction standards are almost never applied retroactively, and are intended to apply to new construction only. This is because, as illustrated in the above example, retroactive application of new construction standards almost never passes a benefit-cost analysis due to the extreme cost of retroactive application." (Pages 28-29)	This is a poor analogy that highlights Witness Stephens' inattention to details provided in my revised direct testimony on pages 90-91, and he is conflating changes to subtransmission planning criteria with construction standards. Subtransmission planning criteria are applied to all subtransmission circuits, not just ones newly constructed. A better analogy to Witness Stephens' recommendation: conducting inspection and maintenance on a bridge to 1920's standards because that was when it was built, rather than using the current best industry practice guidelines.
"Of those distribution substations that do have a back-up source of supply, the back-up capacity is not always adequate for all hours of the year. For example, while back-up capacity may be adequate for 97% of the hours in a year (as an example), there may be some hours of the year when the back-up capacity is inadequate, constituting a violation of capacity limits. In this example, should an equipment outage occur during the 3% of the hours of the year when back-up capacity is not adequate – usually, summer weekday afternoons – a service interruption may be required despite the redundant design available from back-up supply routes." (Page 29, lines 10-17)	Witness Stephens' footnote 29 on page 29 of his testimony notes that with 8,760 hours in a year, a capacity planning violation that occurs 3% of the hours in a year equates to 262.8 hours (8760 x 3%), or ~11 days. It seems that Witness Stephens is inferring that it is acceptable for a customer to experience an outage for up to 11 days. The Company does not agree.
"I agree with the Auditor's assessment that the reliability improvement opportunity offered by most types of spending in this program is small. I also agree with the Auditor's assessment that 24kV subtransmission system retirement is related to 4.8kV distribution circuit conversion. As 4.8kV distribution circuit conversion slows, as I will recommend later in this testimony, 24kV subtransmission system retirement can slow as well." (Page 32, Lines 13-17)	The vast majority of projects identified in the Subtransmission Redesign & Rebuild area are to address capacity issues associated with voltage and thermal violations. See earlier in the table for comments on reliability improvements. It should also be noted that subtransmission work that is being driven by the 4.8kV Conversions program is included in that program.

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Witness Stephens' Claim	Rebuttal
Witness Stephens states that the Company has not provided benefit-cost analysis ("BCAs") for any of the subtransmission projects in the instant case. (Page 33, Lines 4-12) "I further recommend that the Commission require DTE to complete risk informed benefit-cost analyses on any Subtransmission Redesign and Rebuild projects or programs with total capital costs in excess of \$10 million." (Page 34, Lines 10-13)	As stated in Q&A 82 of my revised direct testimony, the Company will develop a comprehensive subtransmission BCA framework designed to evaluate new subtransmission projects. The Company plans to complete the framework before the next rate case filing and will apply the framework to all new subtransmission projects over \$10 million as directed by the Commission in Case No. U-21534. Existing Subtransmission Redesign & Rebuild Program project investments that were authorized by the Commission in Case No. U-21534 and are in progress are assumed to have already met the appropriate burden of proof since the Commission has granted approval for these projects.

1

2 **Q113. Can you summarize your rebuttal of recommendations and statements made**
3 **in the instant case regarding the Company's Subtransmission Redesign &**
4 **Rebuild program?**

5 A113. Yes.

- 6 • The Company appreciates Staff Witness Evans' support for the Company's
7 Subtransmission investments proposed in the three-year 2027-2029 IRM
8 extension but respectfully disagrees that only the alternate investment
9 amount for 2027-2029 should be approved; the proposed alternative 2026
10 and the full 2027-2029 Subtransmission investment levels should be
11 approved.
- 12 • The Company respectfully disagrees with CEO Witness Volkmann's
13 recommendation to decline the Subtransmission investments proposed in
14 the three-year 2027-2029 IRM extension; the Company has a substantial
15 pipeline of projects to select from to meet the full proposed 2027-2029
16 investment levels and will conduct benefit-cost analyses following the

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1 development of the BCA framework before the next rate case filing as
2 directed by the Commission.

3 • AG-MN Witness Stephens' recommendations should be disregarded
4 because they disregard important details provided by the Company in my
5 revised direct testimony and in discovery responses. The Company also
6 disagrees with the incorrect statements made in Witness Stephens' direct
7 testimony and summarized in Table 8 above.

8

9 **General Infrastructure Redesign & Modernization Rebuttal Points**

10 **Q114. Have any intervenors requested that the Commission make additional**
11 **disallowances or direct the Company to undertake any specific activities**
12 **related to distribution infrastructure or processes?**

13 A114. Yes, intervenors have suggested a collection of conceptual proposals listed in Table
14 9 below for the Company to undertake. However, as a group these suggested
15 directives are not well defined and largely lack the detail requisite before more
16 thorough consideration. The time, resources, costs, and other inputs necessary to
17 begin these tasks have neither been discussed nor even listed; the resultant values
18 have not been calculated nor considered; alternatives have not been identified nor
19 compared. In light of the limited explanations and justifications for these proposals,
20 the Company cannot fully respond to all of the unsupported suggestions
21 individually. All of these requested directives should be denied.

Table 9 General Rebuttal Topics

Witness	Rebuttal Point	Rebuttal
ABATE – York	Regarding distribution capital strategic replacements, on page 29, lines 1-7 of Witness York’s direct testimony, she recommends that “the Commission allow only the projected capital expenditures associated with projects that are expected to be in-service during the bridge period and projected test year.”	Company Witness Uzenski addresses this in her rebuttal testimony. Additionally, the Commission found Witness York’s similar proposed adjustments in Case No. U-21297 unpersuasive concluding that “the Commission does not find that the question of whether a project will be completed within the test year is dispositive as to whether that project belongs in rate base.” ⁸³ The Order in Case No. U-21534 reiterated this conclusion, stating that nothing on the record in that case was persuasive enough to deviate from that decision ⁸⁴ . The Company recommends the Commission disregard Witness York’s recommendation again in the instant case.
Staff – Shi	On page 39, lines 5-8 of Witness Shi’s direct testimony, she recommends that the “Commission should require the Company to explain programs and associated expenditures in the exact order used in its tables and exhibits. Aligning the order and labels across narratives, tables, and exhibits will significantly ease review and reduce misinterpretation.”	The Company notes that the development of its Infrastructure Redesign & Modernization pillar exhibits and direct testimony, including tables and figures, is a complex process, but it will consider Staff’s input and make improvements where appropriate. The Company will also discuss the matter with Staff to more fully understand the issue.
MNC - Woolley	On page 24, lines 15-20 of Witness Woolley’s direct testimony, he states that his “analysis indicates that the Company is currently using only a fraction of its available	The Company offers the following brief rebuttal points to Witness Woolley’s principal conclusions on the loading of its transformer assets:

⁸³ Case No. U-21297, Order dated December 1, 2023, p. 84⁸⁴ Case No. U-21534, Order dated January 23, 2025, p. 59

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Witness	Rebuttal Point	Rebuttal
	transformer network capacity” and that “the Company has room to accommodate substantial additional load from electrification. On average, residential line transformers peak at just under 40% of their effective ratings, commercial line transformers peak at just under 15%, and substation transformers peak at roughly 48%.” He goes on to state on page 25, lines 5-9 that “the Company can accommodate substantial electrification before winter peaks begin to materialize. Specifically, the system could reach about 50% vehicle electrification and 20% building electrification before winter peaks exceed summer peaks. This indicates that even with significant electrification, the transformer network has ample effective capacity to manage additional load without triggering immediate upgrades.”	- The capacity related projects do not address "average" loading of the entire system but loading on specific pieces of equipment. - Witness Wolley’s analysis assumes homogenous loading across all transformers, but this is not realistic; a transformer in one corner of the Company’s service territory cannot be used to charge an EV in an opposite corner of the service territory. - Witness Woolley’s analysis only focuses on electrification of existing load and vehicles and does not factor new load. - Winter and off-peak times may be able to accommodate electrification but will exacerbate existing overloads in the summer. - Witness Wooley’s analysis assumes the transformer is the only electrical system component contributing to system upgrade cost and neglects voltage drop over existing secondary conductors at a local level from increased electrification; it also neglects necessary primary system circuit upgrades that would result from the aggregate circuit impact of increased EV penetration. - Witness Woolley’s professional background and qualifications calls into question his merits in determining the optimization of electric utility transformer loading.

1

2 **Q115. Does this conclude your rebuttal testimony?**

3 A115. 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

REBUTTAL TESTIMONY

OF

STEPHEN P. RADEMACHER

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF STEPHEN P. RADEMACHER

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5	has already executed beyond Staff's spend projection that was based on limited	
6	data	7
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8	audit recommendation for further understanding of the program benefits	13
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10	prudent and necessary	19
11	Rebuttal Issue 4: The Company sees the benefit of deploying DA as part of a suite	
12	of programs that will benefit customer reliability, because the complex grid	
13	challenges require a combination of solutions	22
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20	in robust communication paths for critical grid assets that requires immediate	
21	implementation with any future wireless scenarios	34
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24	and justification for the ramp up of investment supports the Company's	
25	projections	40
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28	necessary investments to support DER integration that need to continue to	
29	develop without delays	42
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DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF STEPHEN P. RADEMACHER

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1 **Q1. Please state your full name, business address and by whom you are employed?**

2 A1. My name is Stephen P. Rademacher, One Energy Plaza, Detroit, Michigan 48226.

3 I am employed by DTE Electric (“DTE Electric” or the “Company”).

4

5 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
6 **Company (DTE Electric or Company)?**

7 A2. Yes.

8

9 **Part I. Purpose of Testimony**

10 **Q3. What is the purpose of your rebuttal testimony?**

11 A3. My testimony will rebut the testimony of several witnesses including:

- 12 • Witnesses Stephens and Alvarez on behalf of the Attorney General (AG),
- 13 Michigan Environmental Council (MEC), and Natural Resource Defense
- 14 Council (NRDC), collectively referred to as “AG-MN,”
- 15 • Witness Shi on the behalf of the Michigan Public Service Commission (MPSC
- 16 or Commission) Staff (Staff),
- 17 • Witness Stults on behalf of the City of Ann Arbor (AA),
- 18 • Witnesses Volkmann and Kenworthy on behalf of the Ecology Center,
- 19 Environmental Law & Policy Center, Union of Concerned Scientists, and Vote
- 20 Solar, collectively referred to as “CEO”, and
- 21 • Witness Fitzhenry on behalf of the Association of Businesses Advocating Tariff
- 22 Equity (ABATE).

23 The absence of a discussion of other matters in my testimony should not be taken

24 as an indication that I agree with all other aspects of intervenor testimony.

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1 **Q4. Are you sponsoring any exhibits in this proceeding?**

2 A4. Yes. I am sponsoring the following exhibits:

<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
A-53	TT1	Distribution Automation – Alternative Projection Analyses
A-53	TT2	Distribution Automation – DR DEAG-MN-1.17
A-53	TT3	Distribution SCADA Historian – DR STDE –1.2a
A-53	TT4	Distribution SCADA Historian - DR HH-2.1g
A-53	TT5	NDA Distribution SCADA Historian – Basis Calc
A-53	TT6	NDA Vegetation Mgmt Replatform – DR STDE-1.2h
A-53	TT7	Vegetation Mgmt Replatform – DR STDE-7.8h
A-53	TT8	Mobile Timesheet System – DR STDE-1.2g
A-53	TT9	Mobile Timesheet System – DR STDE-7.8g
A-53	TT10	Distribution Sensing & Monitoring – DR STDE- 1.1c
A-53	TT11	Distribution Sensing & Monitoring – DR HH-2.1c
A-53	TT12	NDA Distribution Sensing & Monitoring – DR STDE-7.3a
A-53	TT13	Distribution Sensing & Monitoring – DR STDE-7.3b

3

4 **Q5. Were these exhibits prepared by you or under your direction?**

5 A5. Yes.

6

7 **Q6. How is your testimony organized?**

8 A6. My testimony is organized around several key themes that emerged across the
 9 witnesses representing various stakeholder groups. For each topic listed in the
 10 Table of Contents, I will provide a detailed discussion that addresses specific
 11 inaccuracies and/or erroneous assumptions presented in their testimony. I will also

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1 explain why certain recommendations made by these witnesses should not be
2 adopted by the Commission.

3

4 **Part II. Distribution Automation**

5 **Q7. Please briefly describe the Distribution Automation Program.**

6 A7. The Distribution Automation (DA) Program is a strategic initiative launched in
7 2021 to modernize the electric grid through the use of technology and automation,
8 and enhance public safety, system reliability, and operational efficiency. The
9 program deploys intelligent field devices—including sensors, switches, and
10 reclosers—designed to enable flexible sectionalizing and automatic circuit
11 reconfiguration. These capabilities allow for faster isolation of faults and
12 restoration of service, particularly during outage events caused by physical damage
13 such as downed wires.

14

15 The DA Program integrates advanced automation and secure communication
16 technologies to support real-time decision-making and remote control of grid
17 assets. To date, the program has installed over 895 reclosers, which play a critical
18 role in minimizing deenergizing the public safety risk of potentially live wires on
19 the ground; as well as customer impact during outages. In 2025 alone through
20 August, reclosers installed within the DA program have prevented 16,000 customer
21 interruptions, as well as over 4 million customer outage minutes. I will further
22 describe the reliability benefits of reclosers below.

23

24 This initiative aligns with the Company's broader grid technology and automation
25 modernization goals and regulatory priorities, including improved resiliency,

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1 enhanced situational awareness, and accelerated outage response. The program also
2 supports compliance with evolving reliability standards and contributes to a more
3 adaptive and responsive distribution system.

4

5 **Q8. Have there been expressions of support for the Distribution Automation**
6 **program investments from the parties in this case?**

7 A8. Several witnesses indicate some level of support for the DA program. As examples,
8 Staff Witness Shi states "... Staff concurs with the Company's position that
9 expanding the deployment of reclosers will substantially enhance grid safety and
10 reliability. Staff strongly supports these efforts."¹ CEO Witness Volkmann, in his
11 discussion of safety reclosers, states "with DTEE's 14,000 wiredowns per year on
12 its 4.8kV system, I agree that mitigating this risk is critical and urgent."² AA
13 Witness Stults³ and AG-MN Witness Stephens⁴ also express support for safety-
14 targeted reclosers.

15

16 **Q9. Have there been other responses from parties concerning the Company's DA**
17 **investments?**

18 A9. Yes, various witnesses expressed concerns, including:
19 Rebuttal Issue 1: Staff Witness Shi expressed concern about the Company's
20 ability to achieve the planned DA program investments for 2025
21 and 2026, based on review of the first four months of 2025
22 investment in the DA program. Witness Shi used this early data
23 to calculate a projected level of annual investment, and based on

¹ Witness Shi Direct Testimony, p. 9, ln. 13-15

² Witness Volkmann's Direct Testimony, p. 23, ln. 7-8

³ Witness Stults Direct Testimony, p. 11, ln. 2-5

⁴ Witness Stephens Direct Testimony, p. 11, ln. 8-9

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1 that, expressed concerns about the Company's ability to
2 construct at the planned investment levels.

3 Rebuttal Issue 2: Staff Witness Shi, CEO Witness Volkmann, AG-MN Witness
4 Stephens, AA Witness Stults, and ABATE Witness Fitzhenry
5 reference the DTE Electric Utility Distribution Audit Report
6 ("Audit" or "Audit Report"), conducted by Liberty Consulting
7 Group and filed in Case No. U-21305, as support for their
8 recommendations to fully or partially disallow DA program
9 investments. They reference an Audit recommendation which
10 calls for a slower initial pace of recloser deployment based on
11 what the auditors saw as a need for better understanding of their
12 likely reliability contribution.

13 Rebuttal Issue 3: Several witnesses support DA reclosers that are targeted to
14 specifically improve safety, but express concerns about those
15 targeted to improve reliability.

16 Rebuttal Issue 4: Several witnesses criticized the reliability benefits provided by
17 DA because the program reduces the number of customers that
18 experience outages, in comparison to investment programs that
19 address the root causes of outages.

20 Rebuttal Issue 5: Several witnesses raise concerns about the methodology of the
21 DA BCA developed by Witness De Stigter that demonstrates the
22 value to the customers.

23 Rebuttal Issue 6: Other concerns by witnesses: AG-MN Witness Stephens argues
24 that the cost-effectiveness of reclosers is overstated, that DA
25 should be done after Tree Trimming (TT) and Pole and Pole Top

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1 Maintenance & Modernization (PTMM), and that reclosers may
2 not function properly. AA Witness Stults concludes that DA is
3 only a short-term fix. ABATE Witness Fitzhenry is concerned
4 the Company has not demonstrated that the totality of
5 investment requested is needed for reliability improvements.
6 CEO Witness Volkman requested a sensitivity analysis because
7 he is concerned that the material and labor costs are understated.

8

9 Rebuttal Issue 1: DTE Electric is on track to meet projected investment levels and has
10 already executed beyond Staff's spend projection that was based on limited data

11 **Q10. What does Staff Witness Shi recommend as a disallowance for DA?**

12 A10. Witness Shi recommends a disallowance of \$83.1 million in 2025 and \$97.5 million
13 in 2026 associated with DA, Exhibit A-12, Schedule B5.4, page 14, line 3.⁵

14

15 **Q11. What was the basis for the recommended disallowances in 2025 and 2026?**

16 A11. Based on data the Company provided in a discovery response produced in June
17 2025,⁶ Staff Witness Shi reviewed the first 4 months of actual DA investments in
18 2025 and assumed an averaged linear investment rate to calculate her estimate of
19 an annual forecast for 2025. Witness Shi's calculated 2025 forecast of \$22.5 million
20 was then subtracted from the Company's 2025 projected expenditures, resulting in
21 a 2025 recommended disallowance of \$83.1 million.⁷

⁵ Witness Shi Direct Testimony, p. 10-11, lines 20-23;1-2

⁶ Exhibit S-10.2, p. 1, Discovery Response to STDE-1.1a-t

⁷ Witness Shi Direct Testimony, p. 10, lines 20-22

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1 Using her calculated 2025 forecast, Witness Shi then applied a 2.66% inflation
2 factor to develop her 2026 forecast of \$23.1 million.⁸ Subtracting the calculated
3 2026 forecast from the Company's projected expenditures results in a 2026
4 disallowance recommendation of \$92.5 million not the stated \$97.5 million, a
5 difference of \$5.0 million.⁹ Although the Company disputes the underlying
6 methodology, as detailed in the discussion below, the additional \$5.0 million in
7 disallowances appears to reflect a potential calculation error. This conclusion is
8 based on the stated calculation approach and the lack of any supplementary
9 documentation or justification provided by Witness Shi.

10

11 **Q12. Does the linear monthly spending assumption employed by Staff in their DA**
12 **investment forecasting methodology provide a reliable and substantiated basis**
13 **for assessing the Company's actual investment capacity and alignment with its**
14 **strategic investment plan?**

15 A12. No. Using four months of data to forecast an annual level of investment in the DA
16 program, uses a limited window of time and is not reflective of more recent months'
17 investment rates. The Company's actual 2025 DA program investments through
18 July, are \$25.3 million, already exceeding Staff's 2025 estimated annual projection
19 of \$22.5 million. Additionally, a linear monthly spending estimate fails to take into
20 account factors and timing embedded in the detailed project management process,
21 including engineering, materials, and labor acquisition and utilization, which
22 typically tend to vary in a non-linear way over time. For a general discussion on the
23 2025 year-to-date investment as a basis for year-end forecast reductions, please see
24 Witness Chiu's Rebuttal Testimony.

⁸ Witness Shi Direct Testimony, p. 10-11, lines 23; 1

⁹ Witness Shi Direct Testimony, p. 11, line 2

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1 **Q13. Do you have other concerns about the forecasting method used by Staff**
2 **Witness Shi?**

3 A13. Yes. Staff Witness Shi analyzed only the non-Infrastructure Recovery Mechanism
4 (IRM) portion of the DA program, rather than considering both the IRM and rate
5 case portions of the DA program. A review of the collective activity offers a more
6 comprehensive investment profile because they are managed together within the
7 DA program.

8

9 **Q14. Do you have additional concerns about the calculations Staff Witness Shi used**
10 **in her projections for the DA Program level of investment for 2026?**

11 A14. Yes. In addition to her incorrect assumption about linear spending patterns, Witness
12 Shi used a 2.66% inflation factor to calculate her projected level of investment for
13 2026. As presented by Company Witness Uzenski in her direct testimony and
14 further supported by Company Witness Bruzzano in his rebuttal testimony, the
15 Company's estimated level of inflation for 2026 is 3.10%. By applying the same
16 methodology that Witness Shi uses, a corrected inflation rate of 3.10% would lead
17 to a total recommendation of \$23.2 million of investment in 2026. This represents
18 a possible \$99.2 thousand disallowance based solely on what the Company believes
19 to be an incorrect inflation rate.

20

21 **Q15. You noted that Witness Shi's calculation was based on the first four months of**
22 **2025 that were provided as part of an early discovery response. What does**
23 **more current data show about the Company's pace of investment in 2025?**

24 A15. Witness Shi used the information that was available from early discovery for the
25 non-IRM portion of the DA program in her projections for the Company's year-

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1 end level of investment.¹⁰ Specifically, she based her projections on the first four
2 months of 2025 actuals, which was approximately \$7.5 million.¹¹ Witness Shi
3 estimated the annual investment by simply multiplying the four month actuals of
4 approximately \$7.5 million by 3, arriving at a year-end forecast of approximately
5 \$22.5 million. Using the actuals through July, the Company has already exceeded
6 Witness Shi's year-end 2025 forecast with a cumulative 2025 investment of \$25.3
7 million through only July 2025, indicating Shi's forecasting methodology points to
8 a potential understatement in the year-end forecast based on current investment
9 trends.

10
11 Given that the Company has already exceeded the level of year-end investment
12 estimated by Witness Shi, the Company has prepared two alternative
13 methodologies for forecasting the 2025 DA program investment in Exhibit A-53,
14 Schedule TT1. These are: (1) start with the 7-month 2025 investment of \$25.3
15 million and apply a linear monthly investment pattern similar to Witness Shi, but
16 projecting forward using July investment levels at \$11.3 million per month, to
17 estimate a year-end total of approximately \$81.7 million; and (2) following the
18 Company's detailed ramp-up plan to achieve the full \$105.6 million as approved in
19 Case No. U-21534 and requested in the current case, which the Company believes
20 provides the most accurate forecast.

21
22 See Figure 1 below for a graphical representation of the various methodologies
23 discussed in this section. The dark teal shading from January to April represents

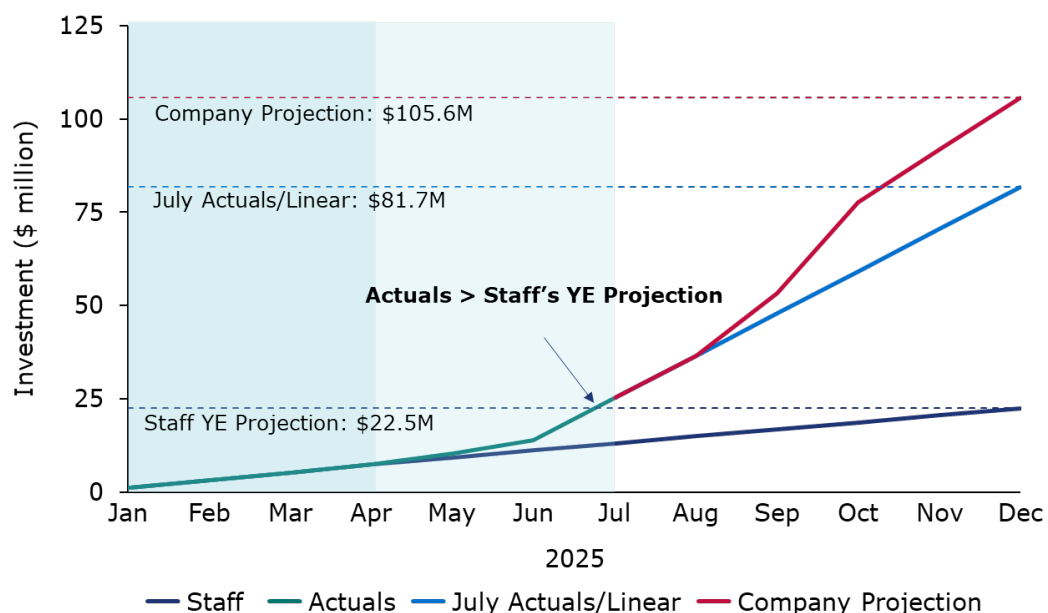
¹⁰ Witness Shi Exhibit S-10.2, p. 1

¹¹ Witness Shi Direct Testimony, p. 9, ln 10, p10, lns 18-19; Exhibit S-10.2, p. 1

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1 actuals used for Staff's year-end forecast; light teal shading through July highlights
2 updated actuals.

3 **Figure 1 Staff's Analysis vs. Other Options**



4

5 **Q16. In addition to the linear spending projection, does Staff Witness Shi rely on**
6 **any other concerns for her recommendation on the level of DA investment?**

7 A16. Yes. Staff Witness Shi expressed a concern about the Company's ability to execute
8 at the higher pace when she stated, "... based on the Company's actual spending
9 performance, [Staff] believes that DTE may be unable to execute the full projected
10 spending within the year. Therefore, Staff recommends aligning the program's
11 budget forecast with DTE's demonstrated spending capability ..." ¹² Witness Shi
12 also draws on an Audit recommendation for support for her proposed levels of
13 disallowance, which I will discuss further in the next section of my rebuttal
14 testimony.

¹² Witness Shi's Direct Testimony, p. 10, lines 12-15

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1 **Q17. Do you agree with Staff's concern about the Company's ability to execute at**
2 **the higher pace?**

3 A17. No. First, as I identified above, the Company has already exceeded Witness Shi's
4 year-end projection, thus demonstrating capability to execute the program at the
5 higher levels projected by the Company, and expects to continue to see increasing
6 levels of investment in 2025. Secondly, as I discuss further below, the Company
7 has a well thought-out and resourced plan to ramp up the DA program over time.

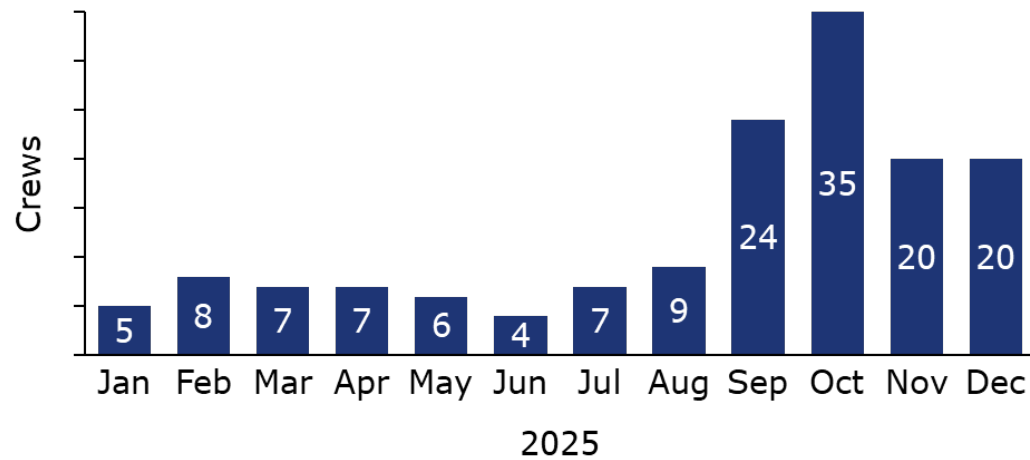
8

9 **Q18. How do you respond to Witness Shi's concerns regarding the Company's**
10 **ability to execute its planned work in 2025 and 2026 for the DA program**
11 **investments?**

12 A18. The Company has and is currently mobilizing resources to ramp-up installations
13 for 2025 and 2026. Figure 2 illustrates that the average monthly number of field
14 crews installing DA equipment in 2025 is rising, aligning with the Company's
15 projected total installations. The increasing number of field crews demonstrates that
16 the Company is planning for and executing the accelerated pace of investment,
17 which supports the Company's year-end projection. Continuing into 2026, the
18 Company plans to ramp relative to the investment levels approved as part of this
19 instant case.

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Figure 2 Average Number of Installation Crews Per Month

2 Rebuttal Issue 2: DA is essential and the BCA is a path towards addressing the audit
 3 recommendation for further understanding of the program benefits

4 **Q19. What concerns did Staff and intervenor witnesses raise regarding the pace and**
 5 **timing of the DA program investments?**

6 A19. Several witnesses referenced an Audit recommendation and generally expressed
 7 the view that the installation of reliability-targeted DA reclosers should be fully
 8 disallowed or slowed down in the near term. Staff Witness Shi uses the Audit report
 9 as one element of her support in calling for disallowances of \$83.1 million in 2025
 10 and \$92.5 million (adjusted from \$97.5 million due to a calculation error) in 2026,
 11 AG-MN Witness Stephens (references the Audit report among other reasons and
 12 calls for an overall \$112.0 million reduction in DA investment in the 2026 test year
 13 as well as a \$735.0 million reduction in IRM investments in 2027-2029. CEO
 14 Witness Volkmann, while making no specific disallowance recommendations, does
 15 reference the section of the Audit calling for a slower deployment of reclosers. AA
 16 Witness Stults states that she does not support the reliability targeted recloser

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1 investments, and ABATE Witness Fitzhenry also briefly references the Audit
2 report on this issue.¹³

3

4 **Q20. What does the Audit report recommend regarding the pace or timing of the**
5 **DA program investments?**

6 A20. In the Final Report of the Utility Distribution Audit of DTE Energy, Part Two,
7 presented September 23, 2024, in Chapter II, Recommendation 13, the Audit
8 Report on page 94 recommended the expansion of the DA program over the plan's
9 later years should be tied to the development of better information about the
10 reliability benefits of reclosers. while at the same time recommending "...
11 accelerated installation [of reclosers] at substation exit points," a reference to 4.8kV
12 safety-focused reclosers.

13

14 **Q21. What was the basis for this recommendation?**

15 A21. The Audit posited that a slower rate of installation for reliability focused reclosers
16 would allow for "...sounder information about current and projected reliability
17 benefits..." which the auditors believed would come from the data provided by a
18 greater number of installed devices.¹⁴

19

20 **Q22. Did the Commission respond to the Audit recommendations for the DA**
21 **program as well as other Company investment programs?**

22 A22. Yes, in the Case No. U-21305 docket, subsequent to Staff filing the Liberty Audit
23 Report on September 23, 2024, the Commission on September 26, 2024 issued an

¹³ Witness Shi's Direct Testimony, p. 9, lines 15-17; Witness Volkmann's Direct Testimony, p 19, lines 21-24; Witness Stephens' Direct Testimony, p. 25, lines 3-4; Witness Stults' Direct Testimony, p 11, lines 4-5; Witness Fitzhenry's Direct Testimony, p. 11, lines 3-12

¹⁴ Case No. U-21305 Audit, Part Two, Chapter II, p. 94

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1 Order that included Commission summaries and questions regarding the Audit
2 recommendations. The September Order was followed by a detailed process of
3 stakeholder comments and utility responses and plans, and resulted in a Final Order
4 issued on June 12, 2025, subsequent to the filing of the instant case.

5

6 **Q23. What did the June 12, 2025 Order in Case No. U-21305 say about the**
7 **investments in the DA recloser program?**

8 A23. The Order specifically reviewed the Audit Part Two, Chapter II, Recommendation
9 13 that I noted above, and included a summary of stakeholder and Company
10 responses regarding the Audit recommendation on the DA program reclosers. The
11 Commission then briefly notes that reclosers as well as other investments support
12 safe, reliable service that may be reasonable and economical. The Order then
13 ultimately concluded:¹⁵

14

15 Thus, the Commission requests that DTE Electric submit, with its next DSP,
16 the company's strategy for improving safety and reliability to its 4.8kV
17 system prior to conversion. The plan should also describe planned timing
18 for Viper recloser installation on the 4.8kV system for safety at the
19 substation exits and for reliability beyond the substation exits and include
20 an assessment that compares tree trimming and other alternative measures
21 for providing safe, reliable service so that the prioritization of expenditures
22 to improve reliability cost effectively may be more clearly discerned.

23

24 In this discussion I have excluded the Order comments regarding specifically safety
25 reclosers, which I will cover later.

26 **Q24. How did Staff Witness Shi represent the Commission's support for this**
27 **specific Audit recommendation?**

¹⁵ Case No. U-21305 Audit Order dated June 12, 2025, p. 36

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1 A24. Staff Witness Shi noted "... a Commission's Order ... stated the Company should
2 slow down its automation program."¹⁶
3

4 **Q25. Does the Company agree with this characterization of the Commission's**
5 **Order regarding the Audit?**

6 A25. No. In the quotation of the DA program conclusion in the Commission's Order
7 above, calling for a strategy, plan, and assessment in the next Distribution System
8 Plan (DSP), the Company would note there is no specific reference to slowing down
9 the current pace of recloser installations.

10 **Q26. How did the Company respond the Audit and the June 12, 2025 Audit Order**
11 **calling for a greater analysis of the reliability benefits and alternatives to DA**
12 **reclosers?**

13 A26. Although the final Audit Order was not available until after the filing of the instant
14 case, the Company reviewed the Audit recommendation and also considered the
15 Commission's feedback from the Order in Case No. U-21534¹⁷, which recognized
16 that the Company is "working toward a BCA for DA moving forward" and
17 expressed anticipation for the forthcoming results.
18

19 **Q27. Did the Company perform a BCA for DA in the instant case?**

20 A27. Yes. The Company performed a comprehensive BCA, further supported in this case
21 by Company Witness De Stigter. This analysis clearly highlights the customer
22 benefits of DA, particularly in enhancing reliability.
23

¹⁶ Witness Shi's Direct Testimony, p. 9, lines 15-17

¹⁷ Case No. U-21534, Order dated January 23, 2025, p. 148

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1 The June 2025 Audit Order requirement, specifically the analysis of benefits, costs,
2 and a review of alternatives,¹⁸ appears to be an expansion of the BCA efforts the
3 Company has already undertaken as part of this case, and will continue to enhance
4 in future DSPs. The alternative solutions to distribution automation proposed by
5 many parties, TT and PTMM, are further covered in Rebuttal Issue 4. In addition,
6 the Company will specifically address the Commission's Audit Order
7 recommendations in the next DSP plan, as requested.

8

9 **Q28. You noted the Commission Case No. U-21305 Audit Order section where it**
10 **calls for an assessment of alternatives and a plan with timing of recloser**
11 **installations in the next DSP. Do you believe this limits or should limit the**
12 **Company's ongoing plans to install DA program reclosers?**

13 A28. No. As I noted above, in calling for additional analysis and planning, the Case No.
14 U-21305 Audit Order did not call for a slowing down or cessation of the program
15 investments that are providing significant safety and reliability benefits to
16 customers, including in the short-term horizon. Instead, the Order requested that
17 additional analyses be included in the next DSP. The next DSP will be filed by
18 June 30, 2026. As part of the DSP development process, the Company reaffirms its
19 commitment to working with stakeholders in analysis of grid safety and reliability
20 and in planning for investments. Continuing with these installations in the interim
21 provides recognized benefits for customers. In addition, these investments were
22 supported by the Commission for both the rate case and IRM for 2025 – 2026.¹⁹
23 Finally, the Audit, in an observation regarding outage root causes and cost-effective

¹⁸ Case No. U-21305 Order dated June 12, 2025, p. 36

¹⁹ U-21534 Order dated January 23, 2025, p. 147-148 (approved current 2025 rate case investment); p. 303 (2026 IRM approved at 2025 levels)

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1 solutions, noted “considering the high incidence of distribution equipment failures,
2 substation transformer failures, and tree caused outages **the continued application**
3 **of system automation is necessary to improve reliability in the short term.”**
4 [emphasis added]²⁰

5
6 **Q29. Does the BCA analysis support the Company’s continued reliability**
7 **investment for the DA program?**

8 A29. Yes. The BCA demonstrates a significant portion of the Company’s distribution
9 circuits will achieve customer benefits in excess of the cost to deploy reclosers for
10 reliability improvements. Further information on the BCA analysis is covered by
11 Company Witness De Stigter.

12
13 **Q30. Has the Company realized improved reliability as a result of the DA program?**

14 A30. Yes. As referenced in my revised direct testimony, the deployment of reclosers in
15 2024 led to the avoidance of over 9,700 customer interruptions and nearly 3.7
16 million outage minutes.²¹ Moreover, through the last week of August 2025, the
17 year-to-date Viper operations have avoided approximately 16,000 customer
18 interruptions and 4.3 million customer outage minutes.

19 **Q31. Does slowing the pace of Distribution Automation make sense for customers?**

20 A31. No. The Company performed a comprehensive BCA, that highlights the customer
21 benefits of DA, particularly in enhancing reliability, in addition to the
22 acknowledged safety benefits. With evidence supporting the reliability installations
23 and a third-party assessment noting the necessity of the Distribution Automation

²⁰ U-21305, Liberty Audit, Part One, Chapter II, p. 25

²¹ Witness Rademacher Revised Direct Testimony, p. 23, lines 8-9

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1 program, the continued implementation of the program is reasonable and prudent.

2 Therefore, the disallowances as noted above should be rejected by the Commission.

3

4 Rebuttal Issue 3: A balanced approach between safety and reliability reclosers is prudent
5 and necessary

6 **Q32. Several interveners, referencing a section of the Audit, support recloser**
7 **installations for safety purposes, while at the same time raising concerns about**
8 **reclosers intended to enhance reliability. Please discuss the witnesses'**
9 **testimony regarding this issue.**

10 A32. As I've discussed above in Rebuttal Issues 1 and 2, and in additional rebuttal to
11 follow, several witnesses provide testimony and propose disallowances for the DA
12 recloser program in general, and reliability-targeting reclosers specifically.
13 However, several witnesses, quoting sections of the Audit, specifically support the
14 Company's planned investments to install safety-targeted reclosers. CEO Witness
15 Volkmann, quoting the Audit, states that he believes that safety recloser
16 investments should be accelerated and completed in 2026.²² AA Witness Stults, in
17 her arguments to limit DA program investment, notes support for safety reclosers
18 when she says "I think it is important to distinguish the Company's spending for
19 safety purposes from its spending that is intended to improve reliability."²³ AG-
20 MN Witness Stephens states "I am therefore not opposing the installation of
21 reclosers on 4.8kV circuits without a neutral wire for safety purposes."²⁴

²² Witness Volkmann's Direct Testimony, p. 19, 5-20

²³ Witness Stults' Direct Testimony, p. 11, lines 2-4

²⁴ Witness Stephens' Direct Testimony, p. 11, lines 8-9

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1 **Q33. How do you respond to these witnesses implying that the Company should**
2 **pursue only safety related recloser investments?**

3 A33. The Company agrees that the enhanced safety benefits associated with DA reclosers
4 installed at the start of 4.8kV circuits are a significant driver of the overall program.
5 However, the Company is also sharply focused on improving reliability and
6 minimizing the impacts of outages on our customers over the next few years.

7

8 The Company determined that it's prudent to utilize a combined approach to
9 address safety related to minimizing the potential hazard of energized downed wires
10 and the less direct safety and health issues that can be mitigated with improved
11 reliability for the Company's customers. Many customers depend on reliable
12 electric service for critical needs including lifesaving medical equipment, air
13 conditioning and heat during extreme weather events, as well as first responder
14 services during emergency situations.

15

16 Second and importantly, as I describe throughout my testimony, the DA recloser
17 program provides significant reliability benefits. As I noted earlier, in 2025 alone
18 through August, reclosers installed within the DA program have prevented 16,000
19 customer interruptions, as well as over 4 million customer outage minutes, and
20 these benefits will continue to increase with the further installation of reclosers.
21 The BCA analysis, submitted in this case and sponsored by Company Witness De
22 Stigter, shows that for many of the planned reliability-based DA circuits, the
23 benefits well exceed the cost.

24

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1 **Q34. What does AG-MN Witness Stephens propose for the level of investment in**
2 **the safety-targeted DA reclosers?**

3 A34. Witness Stephens notes the level of DA program capital investment he believes the
4 Company will spend through 2025 (\$202.6 million), the level of DA investment
5 approved by the Commission for 2026 in Case No. U-21534 (\$24.4 million), and
6 adds them together to conclude that "...sufficient capital (\$227.0 million) has
7 already been approved for DTE to install reclosers on 1,991 4.8kV circuits without
8 a neutral wire."²⁵ He then supports his first calculation with an additional
9 calculation of the total investment needed to support the 1,991 4.8kV circuits
10 without a neutral wire, using information provided by the Company in Case No. U-
11 21845 and shown in Exhibit MNAG-DS-4, which shows \$23.964 million installed
12 cost for 210 automated reclosers and calculates an average recloser installation cost
13 of \$114,000 each. Calculating 1,991 units x \$114,000, his proposed level of needed
14 safety-related recloser investment is \$227.0 million. Since his calculation of
15 approved investment for the total DA program in 2025-2026 matches his
16 calculation of needed investment for safety-targeted reclosers, he then concludes
17 "No additional distribution automation spending is therefore needed for safety."
18 He then notes, "I consider reliability improvements to be the only possible
19 justification for additional investments in distribution automation,"²⁶

20 **Q35. Does the Company have any concerns with Witness Stephens' calculation of**
21 **needed investment levels for DA Program safety-targeted Reclosers?**

22 A35. Yes. First, the \$227.0 million Witness Stephens characterizes as approved
23 investments for 2025 through 2026 is the total DA program investment. Within the

²⁵ Witness Stephens' Direct Testimony, p. 16, lines 10-13

²⁶ Witness Stephens' Direct Testimony, p. 16-17, lines 17 and 1-3

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1 overall program, the Company has and is installing an appropriate balance of
2 safety-targeted as well as reliability-targeted reclosers, as I discussed earlier in
3 rebuttal.

4
5 **Q36. If approved, could the Company implement Witness Stephens' proposal to use**
6 **the currently approved 2025 and 2026 funding for only safety reclosers?**

7 A36. No. The 2025 funding was not approved exclusively designated for safety reclosers,
8 and implementation as proposed is not feasible in August 2025, given that the
9 Company has already invested in reliability reclosers this year. This means not all
10 safety reclosers can be installed at the currently approved amounts. As such,
11 Witness Stephens' proposal cannot be implemented as presented.

12

13 Rebuttal Issue 4: The Company sees the benefit of deploying DA as part of a suite of
14 programs that will benefit customer reliability, because the complex grid challenges require
15 a combination of solutions

16 **Q37. You noted above witnesses' concerns about the DA program mitigating**
17 **outages that have occurred, instead of targeting the root cause of outages. Can**
18 **you provide more detail?**

19 A37. AG-MN Witness Stephens argues "distribution automation is a solution that
20 addresses the symptoms of faults (service interruptions), not the root causes of
21 faults (such as vegetation contact)."²⁷ He then goes on to state his opinion that "It
22 is more cost effective to catch up on routine maintenance activities that must be
23 completed anyway, and that reduce the root causes of services interruptions in the
24 first place, before proceeding to costly solutions (like distribution automation) that

²⁷ Witness Stephens' Direct Testimony, p. 13, lines 5-7

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1 only reduce the impact of service interruptions once they occur.²⁸ Additionally, AA
2 Witness Stults references the Audit report and concludes “[t]hus, DTE should be
3 focused on practices that will minimize the root causes of outages, such as
4 maintaining a robust tree trimming program ..., performing more frequent
5 inspections of its equipment, and keeping up with its Pole Top Maintenance and
6 Modernization (“PTMM”) program.”²⁹

7

8 **Q38. How do you respond to these concerns?**

9 A38. In addition to programs that target the root causes of outages, such as TT and
10 PTMM, the Company’s overall reliability plans address the short-term need to
11 reduce the potential hazard of downed energized wires, reduce the number of
12 customers impacted by outages when they happen through automated and flexible
13 grid reconfiguration, and improve the speed of restoration after a storm has caused
14 damage to the distribution system. The BCA analysis presented by Company
15 Witness De Stigter clearly demonstrates that the proposed investments in
16 Distribution Automation will deliver meaningful value to customers by reducing
17 the duration of power outages.

18

19 The DA and PTMM BCAs were not developed independently, without
20 consideration of the relationship between the programs. The BCA models, as
21 presented by Company Witness De Stigter, deployed DA first and then PTMM,
22 with results showing both programs are beneficial. As part of his rebuttal, Company
23 Witness De Stigter presents an analysis demonstrating that DA remains a valuable
24 investment, even when vegetation management is on cycle and PTMM initiatives

²⁸ Witness Stephens’ Direct Testimony, p. 13-14, lines 21; 1-4

²⁹ Witness Stults’ Direct Testimony, p. 14, lines 16-20

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1 are completed first. TT, PTMM, and DA are complementary programs in the larger
2 plan to improve the safety and reliability of the distribution grid.

3

4 **Q39. Did AG-MN Witness Stephens express another concern about the DA**
5 **program addressing the root causes of outages?**

6 A39. Yes. Witness Stephens referenced an observation section of the Audit when he noted,
7 “[t]he Auditor’s concerns regarding distribution automation are precisely the same
8 as mine. The Auditor’s conclusions include 1) Distribution automation would not
9 be cost-effective if the causes of service interruptions were minimized (for
10 example, by catching up on vegetation management and pole/poletop inspections
11 and maintenance).”³⁰

12

13 **Q40. How do you respond to AG-MN Witness Stephens’ concern?**

14 A40. Witness Stephens appears to have drawn his concern and conclusion by removing
15 an Audit observation regarding the Company’s system automation plans from its
16 proper context. Witness Stephens does not address the section of the observation
17 that immediately followed. The Audit observation continues the analysis with
18 “However, considering the high incidence of distribution equipment failures,
19 substation transformer failures, and tree caused outages, the continued application
20 of system automation is necessary to improve reliability in the short term. It will
21 take many years of effort to otherwise improve reliability by modernizing the
22 distribution system, and to substantially reduce tree-caused outages.”³¹ A review
23 regarding the interplay of DA, TT, and PTMM, specific to the DTE Electrical
24 system is presented in Company Witness De Stigter’s rebuttal testimony.

³⁰ Witness Stephens’ Direct Testimony, p. 15, lines 8-11

³¹ Case No. U-21305 Audit, Part One, Chapter II, p. 25; Presented in Exhibit MNAG-PA-2, p. 29

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1 **Q41. What did AG-MN Witness Stephens recommend regarding the sequence of**
2 **investments in the TT and PTMM programs as well as the DA Program?**

3 A41. Witness Stephens believes that the Commission should not approve future requests
4 to deploy distribution automation for reliability purposes until the backlogs for TT
5 (vegetation management) and PTMM (pole/poletop inspections and maintenance)
6 are cleared.³² Company Witness Steudle addresses Witnesses Stephens³³
7 assertions based on incorrect data presented by Witness Stephens, that the tree trim
8 program has fallen behind in Part 2 of her rebuttal testimony.

9

10 **Q42. How do you respond to this recommendation?**

11 A42. As noted above, the Company strongly supports deploying DA as part of a
12 comprehensive suite of programs designed to enhance customer reliability. The
13 complexity of today's grid challenges demands an integrated approach, and DA is
14 a critical component in delivering effective, system-wide solutions. While
15 programs such as TT and PTMM address the root causes of specific outage types,
16 they are, by themselves, unable to prevent all outages. Furthermore, in many cases,
17 the implementation of root-cause-targeting programs will entail a substantially
18 longer deployment period across the entire system. The DA recloser program is
19 targeted at short term outage mitigations once an outage has occurred, allowing the
20 grid to be safely, quickly, automatically, and flexibly restored, minimizing impacts
21 to customers.

³² Witness Stephens' Direct Testimony, p. 24, lines 17-19

³³ It should be noted that AG-MN Witness Alvarez's also makes similar assertions on pp. 10-11

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1 Rebuttal Issue 5: The data-driven BCA developed for DA is robust and thoroughly
2 supported by Witness De Stigter

3 **Q43. What other comments and concerns did interveners express about the**
4 **Company's BCA supporting the DA Program?**

5 A43. CEO Witness Volkmann describes the BCAs as having "rigorous and sophisticated
6 methodologies"³⁴, but goes on to express a concern that the methodologies do not
7 fully incorporate certain customer costs³⁵ or potential future escalation.³⁶

8
9 AA Witness Stults has concerns about the BCA that include the use of historical
10 outage data to project future outages³⁷, and that the BCA may double count benefits
11 from other investment programs.³⁸

12
13 AG-MN Witness Alvarez expresses several BCA model concerns related to what
14 he believes to be understated costs and overstated benefits.³⁹

15
16 AG-MN Witness Stephens supports the conclusions of AG-MN Witness Alvarez,
17 and focuses on several areas related to the calculation of benefits.⁴⁰

18 **Q44. How is the Company addressing these intervenor concerns?**

19 A44. These concerns about the BCA methodology are specifically addressed by
20 Company Witness De Stigter.

³⁴ Witness Volkmann Direct Testimony, p. 10, line 8

³⁵ Witness Volkmann Direct Testimony, p. 11, lines 15-18

³⁶ Witness Volkmann Direct Testimony, p. 23, lines 10-12

³⁷ Witness Stults Direct Testimony, p. 12 line 14 to p.13 line 8

³⁸ Witness Stults Direct Testimony, p. 13 line 9 to p.14 line 4

³⁹ Witness Alvarez Direct Testimony, p. 37 line 20 to p.40 line 7; Witness Alvarez Direct Testimony, p. 41 lines 1-16; Witness Alvarez Direct Testimony, p. 41 line 17 to p.42 line 21

⁴⁰ Witness Stephens Direct Testimony, p. 18 lines 3-10; Witness Stephens Direct Testimony, p. 12 line 20 to p.13 line 4

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1 **Q45. Does the Company believe that the BCA provides a reasonable approach to**
2 **the calculation of the benefits and costs of the DA Program?**

3 A45. Yes.

4

5 Rebuttal Issue 6: Other concerns raised by intervenors regarding Distribution Automation
6 should not be accepted

7 **Q46. What is AG-MN Witness Stephens asking the Commission to order regarding**
8 **recloser deployment?**

9 A46. Witness Stephens believes that the Commission should order the Company to
10 analyze reliability results from existing deployments before approving additional
11 capital for distribution automation for reliability purposes.⁴¹

12

13 **Q47. How do you respond to this recommendation?**

14 A47. I disagree with Witness Stephens. As discussed in Rebuttal Issue 2, the Company's
15 BCA shows that DA deployment delivers customer savings that exceed costs, based
16 on actual outage data. The Company also provided realized benefits from DA
17 recloser operations in 2024 and 2025 (see Q&A30), highlighting measurable
18 reliability improvements.

19

20 **Q48. Does Witness Stephens provide an alternative calculation on the reliability**
21 **benefits of DA reclosers?**

22 A48. Yes.⁴² Witness Stephens reviewed a limited set of 50 circuits that had reclosers
23 installed in 2020. In his analysis, he started by excluding a number of circuits that
24 did not have a service interruption before and after recloser installation. Then he

⁴¹ Witness Stephens' Direct Testimony, p. 24. lines 20-22

⁴² Witness Stephens' Direct Testimony, p. 21-22

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1 calculated an annual average of customer minutes interrupted pre- and post-
2 deployment. The difference between post- and pre-deployment was termed the
3 annual average savings. Based on his methodology, he claims that “11 of the 44
4 circuits exhibit reliability improvements that approached or exceeded one million
5 customer minutes interrupted annually (a number likely to signify benefits in excess
6 of costs).”⁴³

7
8 **Q49. Do you have concerns about Witness Stephens’ calculation?**

9 A49. Yes. Witness Stephens’ over simplified approach utilizes an inappropriately small
10 subset of reclosers in an attempt to discredit the “rigorous and sophisticated
11 methodologies” employed by Company Witness De Stiger to evaluate the entire
12 system. Witness Stephens’ analysis appears to omit key information about recloser
13 operations and employs a cutoff for benefit-cost assessment that lacks clear
14 justification. A more thorough evaluation of estimated benefits is provided in
15 Company Witness De Stigter’s direct testimony.

16
17 **Q50. What do you mean that Witness Stephens neglects key information about**
18 **recloser operations?**

19 A50. As outlined in my direct revised testimony, reclosers have the ability to isolate
20 outages into smaller sections. If a circuit fault occurs, sectionalizing reclosers can
21 limit the number of affected customers based on equipment topology and outage
22 location.⁴⁴ A circuit could have more or less recorded outage events than previous
23 years based on any number of factors, but when reclosers are installed, the actual
24 number of customers impacted by those events is significantly less than it would

⁴³ Witness Stephens’ Direct Testimony, p. 21, lines 10-12

⁴⁴ Witness Rademacher’s Revised Direct Testimony, p. 19-20, lines 23-25;1-2

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1 have been without reclosers. It is only through an analysis of these outage events
2 that took place and how the number of customers impacted was reduced by the
3 installation of reclosers that you can determine the true resulting impact of the
4 recloser deployment.

5

6 **Q51. Do you have any concerns about Witness Stephens' metric for evaluating**
7 **whether a benefit outweighs the cost?**

8 A51. Yes. Witness Stephens' asserts that avoidance of one million customer minutes
9 interrupted annually is "likely to signify benefits in excess of cost."⁴⁵ The claim is
10 not backed by any references or facts in his direct testimony. When asked in
11 discovery, DEAG-MN-1.17 on page 1 of Exhibit A-53, Schedule TT2, for the basis
12 of the "one million annual interrupted customer minutes", Witness Stephens did
13 not provide a specific basis or support for this number. He only reiterated that
14 "[o]ne million minutes of customer interruptions avoided is a substantial reliability
15 improvement." Ultimately, due to variables such as customer mix and the number
16 of devices, a robust and detailed analysis is essential to truly capture the cost-benefit
17 realities at play rather than an arbitrary cut-off.

18

19 **Q52. What is your recommendation regarding Witness Stephens' alternative**
20 **calculation on the reliability benefits of DA reclosers?**

21 A52. Witness Stephens' oversimplified calculation should be disregarded, as should any
22 resulting conclusions. The BCA presented by Company Witness De Stigter offers
23 a more thorough analysis and serves as a stronger foundation for investment
24 decisions.

⁴⁵ Witness Stephens' Direct Testimony, p. 21, lines 10-12

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1 **Q53. Does Witness Stephens have another recommendation regarding how the**
2 **Commission should support the DA Program?**

3 A53. Yes. Witness Stephens suggests that “the Commission increase the reduction in
4 distribution automation capital investment recommended by the auditor to an \$847
5 million reduction.” The recommendation proposes disallowing all IRM spending
6 from 2027 to 2029 (*i.e.*, \$735.0 million), along with imposing a \$112.0 million cut
7 to the distribution automation request for 2026, leaving only minimal funding for
8 seven circuits Witness Stephens selected and previously approved automation
9 projects.⁴⁶

10

11 **Q54. What is the basis for his proposed disallowance?**

12 A54. The basis for his disallowance is an erroneous filtering of planned work in the
13 Reliability Model cross-referenced to the circuits identified as cost-effective by the
14 DA BCA. Witness Stephens appears to classify all upcoming TT and PTMM work
15 as “catch-up circuits.”⁴⁷ Effectively he reduces the number of cost-effective circuits
16 from 1,189 to seven through a change in terminology that does not appear to be
17 based in fact. The inaccurate underlying premise that DA is not beneficial until
18 completion of all TT and PTMM work is addressed above and in Company Witness
19 De Stigter’s rebuttal testimony for more detail.

20

21 **Q55. What is your perspective on his proposed disallowance?**

22 A55. Slowing the program with a significantly lower level of investment will delay or
23 eliminate reliability benefits. The proposed disallowances are for DA reliability

⁴⁶ Witness Stephens’ Direct Testimony, p. 25, lines 1-8

⁴⁷ Witness Stephens’ Direct Testimony, p. 23, footnote 24: “Exhibit A-23 Sch M12 (Reliability Model), tabs ‘TT Walkdown’ (for vegetation management catch-up circuits) and ‘PTMM Walkdown[.]’ (for pole topletop testing/inspection catch-up circuits)”

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1 investments that have a positive benefit/cost ratio. This level of reduction would
2 not only eliminate significant reliability benefits, it would also reduce the number
3 of safety recloser installations. These levels of proposed reductions would
4 undermine customer service reliability, given the demonstrated benefits and current
5 improvement needs of the distribution system. The specific IRM proposed
6 disallowances are covered by Company Witness Willis in his rebuttal testimony.

7

8 **Q56. What is Witness Stephens' final recommendation regarding how the**
9 **Commission should support the DA Program?**

10 A56. As a final point, Witness Stephens recommends that the Commission reject the
11 "Alternative" proposed by the Company for the 2026 IRM.⁴⁸ The rebuttal for this
12 point will be covered by Company Witness Willis.

13

14 **Q57. Does AG-MN Witness Stephens make any other assertions?**

15 A57. In a section he describes as the "drawbacks of distribution automation", Witness
16 Stephens speculates that "[t]he reclosers may not operate correctly, requiring crews
17 to drive from recloser to recloser to reconfigure the grid manually anyway."⁴⁹
18 Subsequently he expresses a concern that "[i]n storm situations, where damage is
19 widespread, intact circuits from which to reroute power may not be available,
20 negating distribution automation value."⁵⁰

⁴⁸ Witness Stephens' Direct Testimony, p. 25, lines 9-11

⁴⁹ Witness Stephens' Direct Testimony, p. 12, lines 7-8

⁵⁰ Witness Stephens' Direct Testimony, p. 12, lines 8-10

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1 **Q58. How do you respond?**

2 A58. Witness Stephens provides no evidence to support this claim. His general assertion
3 is not supported with data. Furthermore, Company Witness De Stigter has provided
4 and supported BCA input assumptions that account for the availability of installed
5 reclosers.⁵¹

6

7 **Q59. Does AA Witness Stults express any additional concerns about the DA**
8 **program investments?**

9 A59. Yes. Witness Stults believes that the reclosers and other DA Program investments
10 are only a near-term grid solution, suggesting that “[h]eavily investing in DA
11 equipment that will only improve reliability in the short term is unreasonable and
12 imprudent.”⁵² It is worth noting she subsequently mischaracterizes the statement
13 “[d]istribution automation does not directly prevent system events from occurring”
14 as an admission that the Company also believes planned DA investment would be
15 “better spent addressing the underlying root causes of outages.”⁵³ This conclusion
16 is not accurate.

17

18 **Q60. How do you respond to this concern?**

19 A60. A key benefit of the DA program is that it provides near-term reliability benefits to
20 customers and other stakeholders asking for improved reliability now. However,
21 the reclosers and sensors will continue to provide benefits to the grid in the longer
22 term as well, making the investments reasonable and prudent now and in the future.

⁵¹ Exhibit A-28 Schedule R3, Table 3-3

⁵² Witness Stults’ Direct Testimony, p. 14, lines 20-21

⁵³ Witness Stults’ Direct Testimony, p. 14-15, lines 16-21; 1-3; Exhibit AA-13, p. 1

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1 **Q61. What does ABATE Witness Fitzhenry propose as the appropriate levels of DA**
2 **Program investment?**

3 A61. After briefly referencing several sections of the Audit, Witness Fitzhenry proposes
4 holding DA investments for 2026 – 2029 to the levels of the 2025 program, with
5 adjustments for inflation. His support for this level of investment consists of his
6 generalized assertion that “[t]he Company has not demonstrated that the totality of
7 investment requested is needed for reliability improvement.”⁵⁴

8

9 **Q62. How do you respond to this claim by Witness Fitzhenry?**

10 A62. As described in my revised direct testimony and my rebuttal testimony, the DA
11 Program has provided demonstrated safety and reliability benefits for customers.
12 The early program data from 2024 as well as the BCA as described by Company
13 Witness De Stigter provide solid evidence supporting the increases in DA program
14 investment to support a safer and more reliable grid for customers. In addition, he
15 provides no evidence for this recommendation.

16

17 **Q63. What does CEO Witness Volkman recommend with regard to the DA**
18 **program?**

19 A63. Witness Volkman recommends that the Company undertake further BCA analysis
20 with a sensitivity analysis for material and labor escalations.⁵⁵

21

22 **Q64. How do you respond?**

23 A64. Company Witness De Stigter addresses this in his rebuttal testimony.

⁵⁴ Witness Fitzhenry’s Direct Testimony, p. 12, lines 12-14

⁵⁵ Witness Volkmann’s Direct Testimony, p. 23-24, lines 15-20; 1

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1 **Q65. Can you summarize the Company's general rationale for the DA Program and**
2 **how it refutes the criticisms you describe above?**

3 A65. The Company's DA Program is designed to reduce the number of customers
4 impacted by an outage, shorten outage duration, and mitigate potential safety risks
5 on the 4.8kV system. The program was designed to address the unique
6 characteristics of the Company's distribution system. Distribution automation has
7 been proven to be an effective reliability improvement strategy that has been
8 utilized across the industry and is confirmed by Company Witness De Stigter's
9 BCA model to be cost effective. The benefits from this program are a significant
10 part of the Company's plan to reduce customer interruptions and restore customers
11 faster when there has been an interruption.

12

13 **Part III. Grid Automation Telecommunications**

14 Rebuttal Issue 7: Grid Automation Telecommunication is an essential investment in robust
15 communication paths for critical grid assets that requires immediate implementation with
16 any future wireless scenarios

17 **Q66. Please briefly describe the Grid Automation Telecommunications Program.**

18 A66. The Grid Automation Telecommunications Program is a strategic initiative
19 launched in 2021 to provide a reliable, resilient, high bandwidth, low latency
20 communications between critical grid assets such as stations, substations, service
21 centers, communications towers and other key locations. This investment provides
22 the necessary bandwidth for grid modernization efforts and simplifies and replaces
23 many legacy telecommunications systems currently used by DTE Electric. The
24 program utilizes fiber optic and other communications to connect locations to each

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1 other and to DTE Electric data centers, where the data can then be processed by
2 ADMS and other corporate systems.

3

4 **Q67. What is AG-MN Witness Alvarez's position on the planned Grid Automation**
5 **Telecommunication program investment?**

6 A67. Witness Alvarez recommends the following:

- 7 • "Reduce DTE's 2026 test year capital spending request by the \$15.0 million
8 proposed for grid telecom system investment.
- 9 • Collect more information on the economic, technical, operational, and strategic
10 pros and cons of DTE-owned versus public cellular networks before
11 considering additional DTE requests for capital to build its own telecom
12 network." ⁵⁶

13

14 **Q68. Should the Commission adopt Witness Alvarez's recommendations regarding**
15 **Grid Automation Telecommunications?**

16 A68. No, the Commission should not adopt the recommendation to disallow the proposed
17 investment. As detailed in my revised direct testimony, the current fiber
18 telecommunications investments are distinct from future proposals for a private
19 LTE network. These fiber investments are essential for providing high-bandwidth,
20 secure connections to critical grid assets, facilitating grid automation, and
21 supporting distributed energy resource (DER) integration. While future integration
22 with a private LTE network is a potential benefit, it is not the primary justification
23 for the current investment. Evaluating these investments separately ensures a fair
24 and accurate assessment of their value.

⁵⁶ Witness Alvarez's Direct Testimony, p. 49, ln. 12-17

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1 **Q69. Why did DTE Electric present private LTE and long-term scenarios in this**
2 **case if cost recovery for those investments is not currently being requested?**

3 A69. In its Order in Case No. U-21534,⁵⁷ the MPSC requested that DTE Electric provide
4 the entire plan for telecommunications deployment along with a BCA for fiber
5 investments. In Case No. U-21534 DTE Electric provided the pros and cons of a
6 public versus private infrastructure and provided a quantitative analysis of the
7 proposed long-term program in this case for informational purposes. It would not
8 be appropriate to adopt disallowances for current fiber investments, based purely
9 on a future Private LTE investment program because those fiber investments
10 provide benefits to customers regardless of the Company's future investments.
11 Additionally, the investments proposed in this case should not be delayed to collect
12 more information about investments that are outside the scope of this case. Each
13 of the scenarios Witness De Stigter provided in his analysis included the fiber
14 investment because it is required for multiple different use cases, with Private LTE
15 being one future use case.

16

17 **Q70. What is your response to Witness Alvarez's recommendation?**

18 A70. Based on the specific needs of the fiber routes demonstrated in my revised direct
19 testimony and the fact that the investment would be required regardless of the future
20 plans for the Company's wireless communication, I recommend that the
21 Commission reject AG-MN Witness Alvarez's request to disallow critical fiber
22 investments that are required for any future scenario of wireless communication
23 and approve the Company's proposed plans to complete this work.

⁵⁷ Case No. U-21534 Order dated January 23, 2025, p. 154

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1 **Q71. What is your response to AG-MN Witness Alvarez's arguments regarding**
2 **Company-owned telecommunication?**

3 A71. Witness Alvarez focuses narrowly on expanded use cases and asserts that a BCA is
4 unnecessary for increased capacity, claiming the benefits remain unchanged. This
5 assertion disregards the operational advantages of a utility-owned network that
6 supports multiple use cases as well as any limitations imposed by third parties.

7
8 He raises concerns about private cellular flexibility, utility experience in
9 telecommunications, and claims increased resilience and improved cybersecurity
10 in public networks.⁵⁸ These concerns are not supported by evidence. His claim that
11 outsourcing offers greater flexibility ignores the risks of technological instability
12 and the cost of maintaining multiple vendor relationships. Additionally, he does not
13 address how to navigate circumstances when it is necessary to change vendors
14 and/or networks. Overall, his arguments provide no evidence of greater benefits to
15 customers.

16

17 **Q72. Does DTE Electric have prior experience in managing telecommunications**
18 **infrastructure?**

19 A72. Yes. Witness Alvarez incorrectly suggests that DTE Electric is entering a "new
20 business."⁵⁹ In reality, the Company has operated its own telecommunications
21 networks since the 1970s and has managed one of the largest wireless networks in
22 the country for its AMI system since 2013. This is not a new domain for DTE
23 Electric.

⁵⁸ Witness Alvarez's Direct Testimony, p. 48-49, lines 8-18; 1-9

⁵⁹ Witness Alvarez's Direct Testimony, p. 48, line 10

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1 **Q73. What are the benefits of consolidating existing systems into a unified private**
2 **LTE network?**

3 A73. Consolidating disparate existing field communication systems into a unified fiber
4 and private LTE network allows the Company to leverage industry-standard
5 hardware and a broader pool of expertise. Transitioning to private LTE reflects
6 current trends in the utility sector and is expected to lower costs while enabling
7 flexibility for future use cases, including distributed energy resource integration.

8

9 **Q74. How does DTE Electric view services like FirstNet in comparison to a**
10 **dedicated utility network?**

11 A74. Witness Alvarez mentions services like FirstNet as a public option versus a
12 Company-owned cellular network.⁶⁰ DTE Electric uses FirstNet services and our
13 operational experience has shown these services often lack sufficient bandwidth
14 during normal day to day usage and are prone to disruptions during critical events.
15 See Exhibit A-19, Schedule I1.1 for some examples. These limitations demonstrate
16 that such services are unsuitable as a primary communications path. Instead, they
17 are more appropriately used as a backup solution. This evidence underscores the
18 necessity for a dedicated and resilient communications infrastructure.

19

20 **Q75. What does AG-MN Witness Alvarez claim about cybersecurity in a private**
21 **network and do you have any concerns?**

22 A75. Witness Alvarez implies that major carriers offer superior cybersecurity, but this
23 claim is misleading. Carriers do not own or control endpoint devices or the data

⁶⁰ Witness Alvarez's Direct Testimony, p. 48-49, lines 19; 1-3

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1 transmitted over their networks. Security and encryption of the traffic and
2 maintenance of secure devices is the responsibility of the customer, not the carrier.

3
4 Carrier networks serve diverse clients and use cases, which introduces complexity
5 and limits optimization. On a shared network, many different types of traffic need
6 to be supported and are mixed together, making anomaly detection difficult. In
7 contrast, a private network allows for tailored security protocols, direct
8 coordination with grid operations, and immediate response to anomalies. Traffic on
9 a private network is isolated and predictable, enabling more effective monitoring
10 and threat mitigation. Clients on a shared network are also exposed to network
11 management practices that may adversely impact their operations and the risk that
12 other clients do not implement security properly.

13
14 Regardless of the telecommunications network model, DTE Electric must
15 continuously maintain robust cybersecurity capabilities and qualified staff. A
16 private network enhances visibility and control, allowing DTE Electric to respond
17 more rapidly and effectively to potential threats.

18

19 **Q76. Why should Witness Alvarez's recommendation to disallow investment in grid**
20 **telecommunications be rejected?**

21 A76. Witness Alvarez's recommendation is based on future investments outside the
22 scope of this case and does not address the merits of the current proposal. He
23 conflates future private LTE plans with present fiber investments, overlooking the
24 immediate benefits of secure, high-performance communications for critical grid
25 infrastructure.

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1 His testimony skips over the fiber component entirely and prematurely critiques
2 private LTE without providing substantive evidence. He also expresses a general
3 bias against utility capital investment, as addressed in Company Witness Chiu's
4 rebuttal testimony, even when the BCA demonstrates that DTE Electric's approach
5 is the most cost-effective for customers. (Witness De Stigter addresses Witness
6 Alvarez's specific BCA critiques in his rebuttal testimony.)

7

8 Witness Alvarez's arguments rely on unsubstantiated claims about public network
9 flexibility and cybersecurity, while disregarding DTE Electric's decades-long
10 experience in operating telecommunications systems.⁶¹ His recommendation would
11 delay essential grid modernization without valid justification and should therefore
12 be rejected.

13

14 **Part IV. Conservative Voltage Reduction/Volt Var Optimization (CVR/VVO)**

15 Rebuttal Issue 8: Demonstration of execution capacity for the CVR/VVO program and
16 justification for the ramp up of investment supports the Company's projections

17 **Q77. Can you please briefly describe the CVR/VVO Program?**

18 A77. Yes. As described in my revised direct testimony, the CVR/VVO program includes
19 a set of devices that monitor and adjust the reactive power flow on the system and
20 optimize system voltage with the goal to reduce total energy usage and provide
21 better power quality for customers. This is essentially a program that allows the
22 grid to support greater customer loads on the hottest days of summer, in a manner
23 that improves grid efficiency. It is also considered a generation alternative, and as

⁶¹ Witness Rademacher's Revised Direct Testimony, pp. 29-31

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1 such is discussed and supported in the Company's most recent IRP case, Case No.
2 U- 21193.

3

4 **Q78. What does Staff Witness Shi recommend regarding the CVR/VVO program?**

5 A78. Staff Witness Shi recommends disallowing \$7.1 million from the Company's
6 projected 2026 capital expenditures for the CVR/VVO program, Exhibit A-12,
7 Schedule B5.4, p. 14, line 2.⁶²

8

9 **Q79. What is the basis for the recommendation?**

10 A79. Staff recommends the Company receive only an inflationary increase over the 2025
11 budget, not the full 2026 planned investment amount, based on a review of
12 investments in early 2025, and Staff doubts the Company's ability to execute or
13 secure necessary resources for the proposed work scope.

14

15 **Q80. Does Staff's recommendation consider the full context of the implementation**
16 **plan for the CVR/VVO project?**

17 A80. No. Staff's recommendation appears to be based on the assumption that the
18 Company's previous investment levels were constrained by execution capacity or
19 resource limitations. However, this is not accurate. The lower investment levels
20 from 2023 through 2025 were intentionally chosen to coordinate with the
21 completion of the ADMS implementation, which provides the optimization logic
22 to the devices in the field. The Company's 2026 plan encompasses work on more
23 than 70 circuits. The number of planned locations for 2026 is consistent with typical
24 expectations for projects of similar scale and investment level. The program may

⁶² Witness Shi Direct Testimony, p. 8, lines 5-9

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1 further accelerate its execution pace in future years. To support the multi-year
2 effort, more than 3,000 capacitor locations must be evaluated for the installation of
3 control and sensing equipment. In addition, approximately 2,400 voltage regulator
4 locations must be integrated into the program, with a significant portion requiring
5 upgraded control systems. This scope reflects the scale and coordination necessary
6 to ensure effective implementation at a system level.

7

8 **Q81. Do you agree with the reductions to the CVR/VVO program proposed by Staff**
9 **Witness Shi?**

10 A81. No. As I noted above, the significant reductions would hamper the Company's
11 ability to manage and support load and power quality for customers on the hottest
12 days, when it is needed the most. The Company's planned investments are prudent,
13 and necessary to ramp up the number of installations per year, complete the
14 program in a reasonable time frame, and see the visibility and efficiency benefits
15 of the new controls. The total volume justifies the increase from 2025 to 2026.
16 Slowing the program down will delay the energy efficiency benefits and reduce
17 optimization of circuit power flow and customer voltage. I recommend that the
18 Commission allow DTE Electric to fully fund this program.

19 **Part V. Other Technology and Automation Disallowance Rebuttal Points**

20 Rebuttal Issue 9: DERMS, NWA and Grid Edge Insights & New Technology are necessary
21 investments to support DER integration that need to continue to develop without delays

22 **Q82. What does CEO Witness Kenworthy recommend as requirements for**
23 **DERMS, Grid Edge Insights & New Technology and what does he recommend**
24 **for disallowance?**

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1 A82. Witness Kenworthy makes a number of recommendations regarding the content of
2 the Company's business case for the Distributed Energy Resource Management
3 System (DERMS)⁶³ as well as recommending that DERMS, Grid Edge Insights &
4 New Technology should not be approved until a business case and BCA are
5 completed⁶⁴. I will provide detail below on the specific recommendations. He also
6 recommends a number of alternative programs⁶⁵ including Virtual Power Plants
7 (VPP) as a required prerequisite for any funding of DERMS, and Grid Edge
8 Insights & New Technology⁶⁶.

9
10 **Q83. How do you respond to Witness Kenworthy's recommendations?**

11 A83. I disagree. Witness Kenworthy improperly calls for reductions to these valuable
12 investments supporting future DER integration based solely on his opinion on how
13 the programs should be developed and supported. He inaccurately implies that DTE
14 Electric's investment will not support load management nor customer benefits
15 without any meaningful supporting evidence. Although he claims his proposal will
16 deliver customer and grid benefits, it does not include a mechanism to achieve these
17 outcomes in the absence of a platform that is a requirement to manage and operate
18 the necessary programs. Finally, he proposes requiring a VPP be implemented, but
19 provides no rationale as to how the VPP actually acts as an alternative to DTE
20 Electric's proposed investments. He also fails to recommend a business case, BCA
21 or an evaluation of customer benefits of a VPP.

⁶³ Witness Kenworthy's Direct Testimony, p. 9, lines 4-20

⁶⁴ Witness Kenworthy's Direct Testimony, p. 8, lines 18-24

⁶⁵ Witness Kenworthy's Direct testimony, p.10, lines 2-17

⁶⁶ Witness Kenworthy's Direct Testimony, p. 18, lines 2-14

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1 DTE Electric's investments do not prevent future programs from being
2 implemented and do not preclude customer benefits from being considered. Nor do
3 they ignore load management capabilities or more broadly interoperability with
4 third-party aggregators⁶⁷. Instead, by funding the proposed investments in this case
5 for DERMS, Grid Edge Insights and New Technology, DTE Electric will be better
6 positioned to implement the types of customer programs that Witness Kenworthy
7 supports.

8

9 Witness Kenworthy's recommendation would delay DER integration and risk
10 compliance for required regulations such as FERC 2222, which have defined
11 timelines and requirements. If his recommendation is implemented, all capabilities
12 to support DER, both from a customer and grid perspective, will be delayed, and in
13 some cases be impossible to implement in the next few years. It is unnecessary and
14 improper to require implementation of Witness Kenworthy's recommended VPP
15 as a prerequisite for investments in DERMS, NWAs and Grid Edge Insights & New
16 Technology.

17

18 **Q84. What is your recommendation regarding Witness Kenworthy's proposal on**
19 **DERMS, Grid Edge Insights & New Technology and NWA?**

20 A84. I recommend the Commission reject Witness Kenworthy's requirements for these
21 investments and allow DTE Electric to fund these projects to enable the capabilities
22 for more integration of DERs, meet timelines for DER compliance requirements,
23 and enable programs that will be assessed on their own merits in future regulatory
24 filings.

⁶⁷ Which responds to Witness Albers' Direct Testimony, p. 14, ln. 1-13

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1 **Q85. What gaps does Witness Kenworthy claim exist in the current Company**
2 **proposal for DERMS?**

3 A85. Witness Kenworthy's recommendations can be summed up into three general
4 claims about DTE Electric's DERMS, Grid Edge Insights, Non Wire Alternatives
5 and New Technology related investments: ⁶⁸

6 1. DTE Electric has no vision or comprehensive strategy for customer value
7 and demand side management, cost reduction, or participation in grid
8 services markets

9 2. The investments DTE Electric has proposed are narrowly focused on utility
10 aspects of control, visibility and compliance, and do not support load
11 management and programs or customer benefits.

12 3. DTE Electric's NWA projects are just demonstrations that are prioritized
13 over other customer programs.

14 He recommends that until all of these items are addressed by a comprehensive
15 business case, no funding should be approved and his VPP proposal should be
16 implemented instead.

17 **Q86. Do you agree with Witness Kenworthy that these gaps exist in the Company's**
18 **DERMS proposal?**

19 A86. No. Witness Kenworthy does not clearly articulate why he believes his selection of
20 programs provide alternatives to the capabilities that a DERMS is intended to
21 provide, or how his proposed programs would function without a DERMS. He
22 presents his solutions as wholesale replacements for a DERMS rather than future
23 programs that are enabled and supported by a robust DERMS implementation. I do

⁶⁸ Witness Kenworthy Direct Testimony, p. 7, lines 3-19

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1 not agree with these assertions and will address them in the following section of
2 my testimony.

3

4 **Q87. What concerns does Witness Kenworthy have regarding the ability of DERMS**
5 **to enable new customer value propositions including new demand-side**
6 **management programs?**

7 A87. Witness Kenworthy claims that DTE Electric's DERMS proposal "emphasizes
8 system operator control, dispatch optimization, and FERC Order No. 2222
9 compliance, but provides no vision for how DERMS will enable new customer
10 value propositions or comprehensive demand-side management programs." ⁶⁹

11

12 **Q88. Why is this assertion incorrect and why should it not be credited?**

13 A88. This assertion is both inaccurate and dismissive of the clear, phased strategy
14 articulated in my revised direct testimony regarding the DERMS.⁷⁰ The DERMS
15 investment is not limited to system operator control or regulatory compliance;
16 rather, it is a foundational platform designed to enable the future integration of
17 customer-facing programs. Its scalable architecture enables integration of demand-
18 side management and customer value streams as technology, regulatory
19 environment, and customer adoption mature.

20

21 The assertion by Witness Kenworthy should be disregarded as it does not accurately
22 reflect the content and intent of the Company's DERMS strategy.

23

⁶⁹ Witness Kenworthy Direct Testimony, p. 5, lines 16-19

⁷⁰ Witness Rademacher's Revised Direct Testimony, p. 97 lines 9-23, p.98, lines 1-25, p.99 lines 1-14

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1 **Q89. What concerns does Witness Kenworthy raise about the focus on Grid Edge**
2 **and NWA programs?**

3 A89. Witness Kenworthy claims DTE Electric’s grid edge and DER NWA programs
4 “emphasize system intelligence and innovation, but they largely stop at providing
5 visibility rather than mapping out how DER might be actively used for load
6 flexibility,”⁷¹ and further asserts these investments are “designed primarily to
7 provide the utility with visibility and control over distributed resources rather than
8 to maximize customer benefits or develop innovative rate designs and programs
9 that encourage beneficial load flexibility.”⁷²

10

11 **Q90. Why are these assertions incorrect and why should they not be credited?**

12 A90. These assertions are fundamentally flawed and reflect a misunderstanding of both
13 the technical requirements for modern grid operations and the explicit intent of
14 DTE Electric’s investments. The claim that these initiatives “stop at providing
15 visibility”⁷³ ignores the fact that without foundational investments in grid visibility,
16 communications, and control, it is technically impossible to implement, operate, or
17 scale any customer-facing DER program—whether for load flexibility, demand
18 response, or innovative rate design while maintaining safety and reliability of the
19 grid.

20

21 In my revised direct testimony, I made clear that the ability to observe, monitor,
22 and control DERs is not a luxury, but a prerequisite for any safe and effective
23 customer program.⁷⁴ In his recommendation for alternative programs he states,

⁷¹ Witness Kenworthy Direct Testimony, p. 6, lines 6-8

⁷² Witness Kenworthy Direct Testimony, p.6, lines 9-12

⁷³ Witness Kenworthy Direct Testimony, p.6, line 7

⁷⁴ Witness Rademacher Revised Direct Testimony, p. 95, lines 13-22

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1 “These programs utilize DERMS and grid edge technologies to create customer
2 value while providing measurable grid benefits”⁷⁵. His argument reflects a
3 contradiction as he states that DERMS and grid edge technologies are needed to
4 create customer value, but then also claims that his proposal should be adopted first,
5 prior to any investment in a technology platform. Without the ability to implement
6 or administer DER programs, the Company will not be able to properly coordinate
7 with grid operations or provide grid benefits. In fact, Witness Kenworthy
8 recommends defunding the very programs that are seeking to enable DER adoption.

9

10 Very few customer programs, whether demand response, load flexibility, or DER
11 aggregation, can be safely or reliably implemented if the utility cannot observe,
12 communicate with, and control the relevant devices in real time. Without these
13 investments, the future grid will not be reliably operable, DER capabilities would
14 be stunted, and there would be no ability to deliver, measure, or verify any potential
15 customer benefit.

16

17 **Q91. How does witness Kenworthy describe DTE Electric’s NWA pilots?**

18 A91. Witness Kenworthy states that DTE Electric’s Non-Wires Alternatives (NWA)
19 pilots are “narrow technical demonstrations” with “no evidence of scaling” into
20 meaningful customer-facing programs.⁷⁶

21

22 **Q92. Why is this characterization of DTE Electric’s NWA projects incorrect?**

23 A92. The assertion that these projects are “narrow technical demonstrations” with “no
24 evidence of scaling” is ignoring the value of DTE’s approach. My testimony

⁷⁵ Witness Kenworthy Direct Testimony, p. 10, lines 16-17

⁷⁶ Witness Kenworthy Direct Testimony, p. 6, 7, lines 15-16; 1-2

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1 explicitly describes how these pilots are designed to facilitate broader planning and
2 future customer-facing programs and do not restrict future implementation.⁷⁷
3 Moreover, the Grid Edge Insights & New Technology program is not limited to
4 visibility, but is structured to enable the safe, reliable, and scalable integration of
5 new DER and NWA resources.⁷⁸

6

7 Without these foundational investments, many customer programs could not be
8 technically supported (especially those requiring grid integration), the grid would
9 not be safely operable, and there will be no way to quantify potential benefits if
10 DERs cannot be observed and dispatched at appropriate times. Once these
11 technologies are demonstrated and implemented, the ability to apply findings to
12 future programs and scale is greatly enhanced because the foundational work has
13 been completed and the solutions can be repeated. The assertion by Witness
14 Kenworthy should be disregarded as it is contrary to the explicit record.
15 Investments in visibility, control, and system intelligence are not the end goal --
16 they are the essential enablers for all future customer-facing, load flexibility, and
17 NWA programs.

18

19 **Q93. What does Witness Kenworthy recommend regarding New Technology**
20 **Investments?**

21 A93. Witness Kenworthy recommends disallowing funding for New Technology
22 investments, implying these investments are not essential.⁷⁹

⁷⁷ Witness Rademacher Revised Direct Testimony, p. 49, lines 1-20

⁷⁸ Witness Rademacher Revised Direct Testimony, p. 60, lines 6-19

⁷⁹ Witness Kenworthy's Direct Testimony, p. 8, lines 16-21

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1 **Q94. Why is this recommendation fundamentally flawed, and what would be the**
2 **consequences if it were implemented?**

3 A94. Disallowing funding for New Technology would immediately force the Company
4 to halt all evaluation and adoption of new and emerging technology. The Company
5 would be unable to:

- 6 • Respond to changes in the supply chain or vendor equipment (e.g., when
7 manufacturers discontinue or update products).
- 8 • Support any form of integration of customer resources, including
9 vehicle-to-grid, distributed energy storage, or advanced inverter
10 functions.
- 11 • Maintain or develop interoperable communications protocols necessary
12 for safe and reliable grid operations.
- 13 • Participate in substantive external benchmarking, industry
14 collaboration, or technology consulting.
- 15 • Retain or develop engineering staff with expertise in emerging
16 technologies, as these resources would have to be repurposed or
17 eliminated.

18
19 Further, these investments are not optional⁸⁰, but essential for the Company to adapt
20 and maintain safe, reliable, and modern grid operations. Without resources assigned
21 to new technology, the Company would be unable to implement, pilot, or scale any
22 of the very programs and potential customer benefits discussed in this section.
23 There would be no technical or engineering staff available to support program
24 evaluation, no ability to adapt to new industry standards, and no participation in

⁸⁰ Witness Rademacher Revised Direct Testimony, p. 60, lines 1-7

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1 external benchmarking or best-practice development. In effect, the Company would
2 be forced to cease all activities related to technological advancement and repurpose
3 or eliminate the very teams needed to deliver these outcomes.

4
5 Witness Kenworthy's recommendation would directly undermine the Company's
6 ability to serve customers, adapt to industry change, and fulfill its obligations for
7 safety, reliability, and innovation. It would also make it impossible to deliver or
8 evaluate many of the types of customer-facing programs and potential benefits that
9 Witness Kenworthy proposes.

10 **Q95. What does Witness Kenworthy recommend as an alternative to DTE Electric's**
11 **grid integration plan and why is that recommendation insufficient to serve**
12 **DTE's customers?**

13 A95. Witness Kenworthy provides a list of program recommendations and requirements
14 that only include options that he favors and, paradoxically, he claims his approach
15 will create grid benefits while simultaneously recommending that grid integration
16 funding be withheld⁸¹. The ability to target Witness Kenworthy's proposed
17 programs to distribution grid investment is extremely dependent on customer
18 participation, their willingness to abide by the program constraints, as well as
19 having sufficient customer capability in a highly targeted area at the right time to
20 leverage it. In short, the programs proposed by Witness Kenworthy do not have
21 much, if any, impact on distribution-sized areas unless multiple independent factors
22 align. DTE Electric's approach is to support these types of programs as well as

⁸¹ Witness Kenworthy Direct Testimony, p. 10-11, lines 1-23, 1-11

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1 provide for more targeted solutions that increase grid integration and improve the
2 efficiency of DERs.

3

4 It is unclear how any measurable customer or grid benefits would be gained if the
5 investment in DERMS, and Grid Edge technologies were disallowed. DTE Electric
6 has taken a measured approach to NWA pilots and programs to develop a Michigan
7 based understanding of EV charging, distributed solar and storage, demand
8 response, and energy efficiency programs. These investments are foundational to
9 enable future programs and, without this baseline, limited visibility into grid
10 operations and customer behavior would make inequitable programs difficult to
11 undo in the future. DTE Electric has used these pilots to understand what
12 capabilities the Company needs to build to be able to scale these programs in the
13 future to the widest customer base possible.

14

15 One of the key capabilities DTE Electric needs is a system like DERMS and a
16 robust metering capability to be able to create positive benefits for scaling these
17 programs. Requiring a comprehensive assessment of all potential benefits prior to
18 having baseline capabilities to implement programs and measure their effectiveness
19 delays and hinders the opportunity to implement and test customer-facing programs
20 incrementally. Witness Kenworthy's proposal presents an unnecessary hurdle to
21 customer participation. While Witness Kenworthy expresses concern about "utility
22 control"⁸², his recommendation would result in delaying and deferring grid
23 integration, resilience, renewable and distribution system optimization, and
24 customer benefits from DERs.

⁸² Witness Kenworthy's Direct Testimony, p. 6, lines 9-12

Line
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1

2 **Q96. Does the Company agree with the recommendations of Witness Kenworthy**
3 **regarding requiring the creation of a VPP program prior to funding**
4 **investments in Grid Edge and DERMS?**

5 A96. No, Witness Kenworthy makes no link between the Company's plans and the
6 necessity of a VPP program and introduces this as a barrier to integration of DERs
7 by delaying the implementation of useful capabilities. Witness Kenworthy is
8 obviously an advocate for VPP, but he has offered no comprehensive set of use
9 cases, no BCA, and no clear benefits for customers, nor a discussion of what it
10 would take to administer or successfully operate a VPP. There is no reason to delay
11 technical integration of DERs, nor tie DERMS to a specific type of program such
12 as a VPP that should be evaluated on its own merits. Further discussion of VPP
13 programs and other DTE Electric offerings is provided in Witness Leuker's
14 testimony.

15 **Q97. What does DAAO Witness Kinkhabwala recommend in his testimony**
16 **regarding the use of customer sited NWAs as resiliency alternatives to grid**
17 **investment?**

18 A97. Witness Kinkhabwala recommends the utility could fund customer-sited solar and
19 storage resources as a way to provide grid resilience and as a NWA to grid
20 investment.⁸³

⁸³ Witness Kinkhabwala Direct Testimony, p. 45, lines 17-22

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1 **Q98. How would you respond to his proposal?**

2 A98. Witness Kinkhabwala's proposal does not seem practical. It relies on outdated
3 solar and battery system costs and an overly optimistic assessment of solar
4 production in Michigan by using numbers that are more appropriate for a state like
5 Arizona.⁸⁴ These production numbers grossly underestimate the amount of solar
6 and storage needed for an individual household in the months of November through
7 February where there is reduced sunlight and shorter days. In comparison, when
8 using industry standard tools such as PVWatts⁸⁵ to estimate production there are
9 many days that the customer, even after implementing substantial load reduction of
10 over 50%, would be unable to serve their energy needs for many hours of the day
11 and in some cases for stretches of days at a time. To successfully serve the customer
12 through the winter months in Michigan, correcting for the extremely optimistic
13 production values assumed in their analysis, and including corrections for outdated
14 regional pricing information, the estimated cost of a sufficient solar and storage
15 system is up to five times more than what is calculated by Witness Kinkhabwala.
16 To mitigate this, a customer could make even more aggressive cuts to their load,
17 but it is uncertain how customers would respond to this, especially in the colder
18 months. In the absence of grid investment to address root causes, forcing each
19 customer in an area to rely on and maintain a very expensive system at their home
20 calls into question how many customers would agree to this type of solution versus
21 a grid investment that resolves the root cause and benefits all connected customers
22 in the area.

⁸⁴ Witness Kinkhabwala Direct Testimony, p. 48, lines 13-14

⁸⁵ Available at [PVWatts Calculator \(nrel.gov\)](https://pvwatts.nrel.gov/), accessed September 10, 2025

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1 Furthermore, Witness Kinkhabwala uses an arbitrarily short lifetime for traditional
2 grid program effectiveness and does not address how his solution solves the root
3 cause when an event occurs on the distribution system. When taking into account
4 the substantially higher system cost needed for winter months and correcting for
5 his discounting the useful life of utility solutions, Witness Kinkhabwala's proposal
6 is not a viable solution for most (if not all) customers.

7

8 DTE Electric has established mechanisms to evaluate NWAs that will provide
9 benefit and cost savings to customers, and in some specific cases, a solar plus
10 storage resiliency solution may make sense versus a traditional grid upgrade. In
11 those cases, DTE Electric will pursue the appropriate option to meet the
12 requirements and rigorously vet the solution to ensure it meets customer needs.
13 However, applying Witness Kinkhabwala's approach everywhere, especially with
14 the high unit cost of small-scale DER systems, is impractical and prohibitively
15 expensive. Additionally, his proposed solution still does not address root causes of
16 outages. Therefore, Witness Kinkhabwala's proposal provides little to no resiliency
17 benefit, is insufficient to serve the majority of customer needs at a price point that
18 is comparable to traditional grid investment, and should be rejected.

19

20 Rebuttal Issue 10: Distribution SCADA Historian

21 **Q99. Does Staff Witness Shi have concerns with the Company's Distribution**
22 **SCADA Historian investment?**

23 A99. Yes. Staff Witness Shi claims that "the Company has not provided details
24 regarding the vendor from whom the renewal of licenses will be purchased." ⁸⁶

⁸⁶ Witness Shi's Direct Testimony, p. 13, lines 26-27

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1 Additionally, Witness Shi also claims that “the basis for the \$5 million request is
2 unclear and represents a substantial expenditure. Staff’s position is that both the
3 Commission and ratepayers should have full transparency before approving such a
4 cost. Therefore, Staff recommends disallowing 50 percent of the requested amount
5 (\$2.5 million) pending submission by the Company of a renewal invoice or other
6 documentation substantiating the cost.”⁸⁷

7

8 **Q100. How do you respond to Staff Witness Shi’s assessment?**

9 A100. While I appreciate Staff Witness Shi’s interest in additional information, I disagree
10 with her basis for the recommendation to disallow 50% of the requested amount.
11 The Company explained the nature of the request (\$5 million for SCADA Historian
12 software license renewals); the vendor’s name, the “basis for the request” and the
13 invoice for the \$5 million request were not requested in discovery. The absence of
14 these inquiries should not form the basis for disallowance.

15

16 **Q101. Can you summarize how the Company has been responsive to questions from**
17 **Staff Witness Shi and other witnesses regarding the Distribution SCADA**
18 **Historian?**

19 A101. The Company was responsive to questions asked during the Audit and Discovery
20 phase. The Company provided information regarding unit cost for licensing in
21 STDE- 1.2a⁸⁸. Additionally, the Company provided a description of the necessity
22 of the multi-year license and information on cost in HH-2.1g⁸⁹ and Exhibit A-23
23 Schedule M7, pages 48-51.

⁸⁷ Witness Shi’s Direct Testimony, p. 13, lines 27-30, p.14, lines 1-2

⁸⁸ Exhibit A-53 Schedule TT3

⁸⁹ Exhibit A-53 Schedule TT4

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1 **Q102. Is the Company prepared to disclose the vendor?**

2 A102. Yes. The vendor the Company uses is Schnieder who owns AVEVA. The Company
3 has used their Distribution SCADA Historian software (PI system) for over thirty
4 years.

5
6 **Q103. Is the Company prepared to disclose the basis of the \$5 million request?**

7 A103. Yes. The basis of the \$5 million request is in Exhibit A-53 Schedule TT5.

8

9 **Q104. Can you provide a reason for the single multi-year licensing request in 2026?**

10 A104. Yes. The 2026 license investment is a vendor-based formula that was
11 confidentially negotiated. With the single multi-year licensing investment in 2026,
12 the Company can lock in the cost to prevent any unexpected increases. Please see
13 Exhibit A-53 Schedule TT5 for more information on pricing.

14

15 Rebuttal Issue 11: Mobile Equipment Replacement

16 **Q105. Does Staff Witness Shi have concerns with the Mobile Equipment**
17 **Replacement program?**

18 A105. Yes. Witness Shi recommends disallowing \$1.8 million of the 2026 request.
19 Witness Shi states in her testimony that “The Company requested funds for mobile
20 device replacement in prior years but did not spend them. Staff cannot verify the
21 necessity of replacing all 1,556 field iPads, 75 MDTs without an electric dock, and
22 354 MDTs with an electric dock in a single year. Staff recommend replacing half
23 of these units in the test year to allow for potential price reductions and
24 technological improvements, and to explore more cost-effective alternatives.”⁹⁰

⁹⁰ Witness Shi’s Direct Testimony, p. 14, lines 21-23, p.15, lines 1-4

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1 **Q106. How do you respond to this recommendation?**

2 A106. This recommendation overlooks the accumulated need created by three years of
3 deferred replacements (2023–2025). The 2026 request is not an overallocation of a
4 single year but the first major replacement cycle after a multi-year pause,
5 addressing more than 1,900 devices that are outdated or past End-of-Life. The field
6 iPads and MDTs are critical operational tools—essential for outage restoration,
7 storm response, and daily safety tasks. Delaying half of the necessary replacements,
8 as recommended, would leave a significant portion of the fleet vulnerable to
9 failures, cybersecurity gaps, and compatibility issues.

10

11 **Q107. Why is the Company proposing to replace the identified number of devices in**
12 **a single year?**

13 A107. The deferral of mobile equipment replacements created an accumulated need and
14 2026 represents the first major replacement cycle since that deferral. Without
15 executing the replacement in full, field crews, supervisors, and storm response
16 teams will be left operating with outdated and past End-of-Life (EOL) devices,
17 directly impacting reliability, compatibility, and security.

18

19 **Q108. Can the replacements be phased in over multiple years as Staff suggests?**

20 A108. The replacement need is not incremental—it is a catch-up cycle after three years of
21 deferral. Stretching replacements further would prolong exposure to failing
22 equipment, reduce productivity, and compromise storm response readiness. In
23 addition, mixing multiple generations of devices complicates application support,
24 increases IT costs, and introduces cybersecurity vulnerabilities. A consolidated
25 replacement in 2026 enables uniform reliability, compatibility, and maintainability

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1 across the fleet. Older devices no longer receive Operating System updates or
2 security patches, creating known vulnerabilities. This is inconsistent with corporate
3 IT standards and exposes DTE Electric to cybersecurity risk. In addition, it conflicts
4 with compliance expectations under NERC/CIP and other security frameworks.
5 Replacement ensures field devices remain secure, reliable, and aligned with
6 enterprise IT and regulatory standards.

7 **Q109. Did the Company consider cost-effective alternatives or potential future price**
8 **reductions?**

9 A109. Yes. Mobile devices are sourced from a vetted supplier that meets safety and
10 pricing standards. These devices are procured in bulk to optimize cost efficiency.
11 However, delaying replacements in hopes of future price reductions would extend
12 operational and cybersecurity risks. Mobile device pricing is influenced by market
13 dynamics, vendor agreements, and supply chain conditions, making year-over-year
14 cost reductions inconsistent and difficult to assume. Chip shortages, inflation, or
15 tariffs can increase costs rather than decrease them.

16

17 Rebuttal Issue 12: Vegetation Management Replatform

18 **Q110. Does Staff Witness Shi have concerns with Vegetation Management**
19 **Replatform?**

20 A110. Yes. Witness Shi recommends disallowing \$1.6 million (half of the \$3.2 million
21 2026 allocation) unless the Company provides in rebuttal satisfactory responses to
22 her concerns. Witness Shi states that “Company witness Rademacher’s response
23 in STDE-1.2.h (Exhibit S-10.1) [also provided as Exhibit A-53 Schedule TT6]
24 indicates that the Company will need to replace 850 Mobile Licenses, 850 Work

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1 Management Licenses, 100 Scheduler Licenses, 5 Administrator Licenses and
2 ArcGIS Pro Licenses in the test year. And roughly \$600,000 is for software licenses
3 and another \$600,000 is for end-of-life hardware replacement. Staff questions the
4 need for such quantities in a single year, whether bulk discounts were sought, and
5 whether lower-cost alternatives were considered. Staff also seek justification for
6 the \$2.0 million labor cost, including workforce and hours required.”⁹¹

7

8 **Q111. Does the Company agree with the recommendation for disallowance of \$1.6**
9 **million for the 2026 request?**

10 A111. No. The Company disagrees with the assessment regarding the disallowance. The
11 absence of these inquiries in the audit and discovery phase should not form the basis
12 for disallowance, and the following section addresses these questions.

13

14 Additionally, the Company has provided detailed, reasonable estimates for 2026
15 that reflect the breadth of work required. The Company was also fully responsive
16 to questions asked during audit and discovery. The Company provided a budget
17 breakdown in the test year in STDE 7.8h⁹². Additionally, as noted by Staff Witness
18 Shi in her testimony⁹³, the Company provided details on the unit cost and pricing
19 (software licenses, end-of-life hardware, and labor) in STDE 1.2h⁹⁴.

20

21 **Q112. Why is DTE Electric requesting this number of licenses in a single year?**

22 A112. The request for 850 licenses reflects operational realities in Tree Trimming. Each
23 summer, vegetation management activity surges, requiring rapid onboarding of

⁹¹ Witness Shi’s Direct Testimony, p. 16, lines 11-20

⁹² Exhibit A-53 Schedule TT7

⁹³ Witness Shi’s Direct Testimony, p. 16, lines 11-15

⁹⁴ Exhibit A-53 Schedule TT6

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1 contractors and sometimes entirely new vendors. In prior years, license shortages
2 caused access constraints that prevented crews from engaging with critical
3 applications in real time. By establishing this number of licenses, the Company
4 ensures uninterrupted accessibility, prevents recurring license gaps, and maintains
5 operational continuity during peak trimming cycles.

6

7 **Q113. Were bulk discounts or lower-cost alternatives explored?**

8 A113. Yes, the Company conducted a comprehensive RFI competitive sourcing process
9 in 2023, engaging six vendors. In 2025, the evaluation progressed through detailed
10 RFP reviews, which included architectural assessments, additional peer utility
11 benchmarking, and pilot testing to support the final selection.

12

13 **Q114. Can you provide a justification and cost breakdown for the \$2 million labor**
14 **cost?**

15 A114. Yes. The \$2 million labor request reflects the scope and rigor required in 2026 for
16 a secure enterprise-grade implementation. Labor costs for 2026 were carefully
17 scoped and itemized as follows:

- 18 • DTE Electric internal resources: 8,100 hours (~\$1 million) covering project
19 management, architecture, IPS security, internal development, data
20 conversion, and UAT
- 21 • Contractor support: 2,600 hours (~\$280,000)
- 22 • External Development (vendor): \$400,000 (fixed cost)
- 23 • Data Conversion/Migration (vendor): 2,080 hours (~\$250,000)

24 These allocations are consistent with major enterprise application rollouts and
25 ensure proper governance, cybersecurity compliance, data migration, and testing.

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1 Rebuttal Issue 13: Mobile Timesheet System (MTS)

2 **Q115. Does Staff Witness Shi have concerns with the Mobile Timesheet System**
3 **(MTS) project?**

4 A115. Yes. Witness Shi recommends disallowing \$700,000 or half of the projected \$1.4
5 million the Company is requesting due to lack of detail. Witness Shi states in her
6 testimony, “As this is a new project, Staff seeks detailed justification of labor costs,
7 including the number of personnel and work hours required.”⁹⁵

8

9 **Q116. Do you agree with this recommendation?**

10 A116. No. As outlined in my revised direct testimony⁹⁶, MTS will replace a 20-year-old
11 system currently used by the Overhead and Underground crews. This technology is
12 over 20 years old, well past its designed lifecycle, and is no longer supported for
13 updates, or vendor expertise. Continued reliance creates escalating risks of failure,
14 higher maintenance costs, and incompatibility with modern systems. The absence
15 of these inquiries in the audit and discovery phase should not form the basis for
16 disallowance, and the following section addresses these questions.

17

18 **Q117. Can you summarize how the Company has been responsive to Staff’s questions**
19 **regarding the Mobile Timesheet investment?**

20 A117. The Company was fully responsive to questions asked during the audit and
21 discovery phase. The Company provided a description of the unit labor component
22 in STDE 1.2g.⁹⁷ Additionally, the Company provided details regarding the budget
23 breakdown for the test year in STDE 7.8g.⁹⁸

⁹⁵ Witness Shi’s Direct Testimony, p. 15, lines 21-22

⁹⁶ Witness Rademacher’s Revised Direct Testimony, p. 131, lines 1-25, p. 132, lines 1-5

⁹⁷ Exhibit A-53 Schedule TT8

⁹⁸ Exhibit A-53 Schedule TT9

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1 **Q118. Can you provide the requested breakdown of labor justification to complete**
2 **this project?**

3 A118. Yes. The following provides a clear plan for scope, staffing, and cost allocation.
4 DTE Electric IT will provide a dedicated development team of 7–9 people, led by
5 a project manager, including designers, testers, data engineers, and developers. The
6 2026 work scope includes designing and delivering the user interface with core
7 timesheets, defining and implementing key business workflows, and beginning
8 integrations with Maximo and SAP.

9
10 Planned activities for 2026 and associated costs include:

- 11 • Discovery, Design (User Experience and Technical), User Interface,
12 Backend development – Internal Labor estimated at \$1.1 million (9,200
13 hours)
- 14 • Integration Services: \$300,000 (fixed costs)

15
16 These allocations reflect the estimated work and resources needed to deliver the
17 first year of a secure, enterprise-grade application.

18
19 Rebuttal Issue 14: Distribution Sensing and Monitoring

20 **Q119. Does Staff Witness Shi have any concerns about the Distribution Sensing and**
21 **Monitoring program?**

22 A119. Yes. Staff Witness Shi claims in her testimony that “given that only a small
23 fraction of the projected 2025 budget was spent in the first four months, Staff
24 considered the likelihood that the Company prioritized other urgent projects or
25 lacked sufficient manpower to execute the planned expenditures. Based on this,

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1 Staff recommends adjusting the forecasted expenditures.”⁹⁹ Witness Shi has
2 recommended a disallowance of \$2.6 million in 2025 and \$845,623 in 2026.¹⁰⁰
3

4 **Q120. Do you agree with Staff Witness Shi’s assessment?**

5 A120. No. While Staff agrees with the Company that the sensors are essentially “the eyes
6 and ears of the grid”¹⁰¹ and that they play a critical role in outage restoration by
7 identifying and locating faults, thereby enabling the efficient dispatch of repair
8 crews, Witness Shi has made inaccurate assumptions on the spending profile¹⁰² of
9 the program based on just the first four months of the projected 2025 budget.
10

11 **Q121. Why are Staff Witness Shi’s assumptions on the spending profile of the**
12 **program based on just the first four months of the projected 2025 budget**
13 **inaccurate?**

14 A121. Staff witness Shi’s assumptions are inaccurate because they rely on a linear
15 extrapolation of spending from just the first four months of 2025. This approach
16 overlooks several key factors like seasonal construction patterns, project
17 management dynamics which follow a non-linear timeline and vary throughout the
18 year and, finally, installation and purchasing cadence which does not align with a
19 simple monthly average. This analysis lacks consideration of the full project
20 lifecycle and operational realities, leading to an inaccurate spending profile.

⁹⁹ Witness Shi’s Direct Testimony, p.12, lines 5-9

¹⁰⁰ Witness Shi’s Direct Testimony, p. 12, lines 11-18

¹⁰¹ Witness Rademacher’s Revised Direct Testimony, p.46, line 15

¹⁰² Exhibit A-53 Schedule TT10

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1 **Q122. Has the Company provided an example of such non-linear spending?**

2 A122. Yes. For example, as mentioned in STDE 7.3b (Exhibit A-53 Schedule TT13), the
3 overhead (OH) line sensors were procured in 2023 intended for a 2025 installation.
4 Similarly, the Company plans to pre-purchase a bulk order of OH sensors in 2025
5 for installation in 2026. Of the total \$3.5 million expenditure for the program,
6 approximately \$2.0 million is allocated in December for OH line sensor purchases
7 in 2025, demonstrating a forward-spending non-linear approach to budgeting.

8

9 **Q123. Does the Company have any other concerns with assumptions made by**
10 **Witness Shi in her analysis of sensor costs?**

11 A123. Yes. Staff Witness Shi uses a unit cost for 2025 of \$700.70 multiplied by an
12 inflation factor of 2.73%.¹⁰³ This same methodology is applied for 2026 with an
13 inflation factor of 2.66%. The Company has demonstrated in responses to HH-
14 2.1c¹⁰⁴ and STDE7.3a¹⁰⁵ that there are different programs and unit prices for
15 underground (UG) (Single phase and Three Phase) and OH line sensors to consider.

16

17 **Q124. Will the Company be able to execute the projected expenditure for 2025?**

18 A124. Yes. The Company is on track to execute the projected 2025 expenditure. For
19 example, considering the OH line sensors installation, the year-to-date actuals
20 through July 2025 are \$259,000 with 294 installed OH sensors. The Company is
21 projected to spend an additional \$241,000 to install 156 OH sensors by the end of
22 the year. Finally, the Company will spend approximately \$2.0 million in December
23 2025 on material purchases. As outlined in STDE 7.3b¹⁰⁶, Exhibit A-23 Schedule

¹⁰³ Witness Shi's Direct Testimony, p. 12, lines 11-12

¹⁰⁴ Exhibit A-53 Schedule TT11

¹⁰⁵ NDA Exhibit A-53 Schedule TT12

¹⁰⁶ Exhibit A-53 Schedule TT13

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1 M7, and page 12-15 of my revised direct testimony, this spending profile reflects
2 the Company's proactive procurement strategy and supports timely execution of
3 the 2025 plan (450 OH installed sensors, and approximately 480 purchased sensors
4 for \$2.5 million).

5 **Q125. Why is the Company pre-purchasing sensors prior to the installation year?**

6 A125. As outlined in STDE 7.3b (Exhibit A-53 Schedule TT13), this forward-looking
7 procurement strategy allows the Company to mitigate supply chain constraints by
8 securing materials early, optimizes bulk purchasing opportunities for cost
9 efficiency, and supports efficient construction planning and deployment by aligning
10 procurement with the upcoming year's schedule.

11

12 **Q126. Does this conclude your rebuttal testimony?**

13 A126. 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

REBUTTAL TESTIMONY

OF

JASON D. DE STIGTER

"PUBLIC"

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF JASON D. DE STIGTER

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1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed?**

3 A1. My name is Jason D. De Stigter. My business address is 9400 Ward Parkway,
4 Kansas City, Missouri 64114. I am employed by 1898 & Co. as the Director of
5 Utility Investment Planning in our Utility Consulting Practice.

6

7 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
8 **Company (DTE Electric or Company)?**

9 A2. Yes.

10

11 **Purpose of Testimony**

12 **Q3. What is the purpose of your rebuttal testimony?**

13 A3. The purpose of this testimony is to rebut certain positions of:

- 14 • Witness Paul Alvarez on behalf of the Attorney General (AG), Michigan
15 Environmental Council (MEC), and Natural Resource Defense Council
16 (NRDC), collectively referred to as “AG-MN”
- 17 • Witness Dennis Stephens (AG-MN)
- 18 • Witness Colin Fitzhenry on behalf of the Association of Businesses
19 Advocating Tariff Equity (ABATE), and
- 20 • Witness Curt Volkmann on behalf of the Ecology Center, Environmental
21 Law & Policy Center, Union of Concerned Scientists, and Vote Solar,
22 collectively referred to as “CEO”
- 23 • Witness Melissa Stults on behalf of the City of Ann Arbor “AA”.

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1 Specifically, the purpose of my testimony is to rebut three main claims alleged to
2 discredit the validity and credibility of the Benefit Cost Analyses (BCA) performed
3 by 1898 & Co. The three main claims are:

- 4 1. 1898 & Co.'s models are biased (Alvarez)
- 5 2. The BCA underestimates investment costs (Alvarez, Stephens, Fitzhenry,
6 and Volkmann)
- 7 3. The BCA overestimates benefits (Alvarez, Stephens, Stults, and Fitzhenry)

8
9 In my testimony I will demonstrate that these claims are not credible because they
10 are based on incorrect premises, misunderstanding of the 1898 & Co. modeling,
11 and/or inaccurate, self-performed analyses of the complaining witnesses.
12 Therefore, any recommendations derived from these claims are not valid and
13 should be disregarded. Further, based on rebutting these claims, I will demonstrate
14 the 1898 & Co. Benefit Cost Analysis is credible, reliable, and a valuable tool for
15 investment decision making, especially in understanding if investments are
16 expected to provide benefits in excess of costs for customers. My testimony is
17 organized by these three main claims with a section to address CEO Witness
18 Volkmann's concerns about recent escalation trends and the escalation rates used
19 by both DTE and 1898 & Co.

20
21 The absence of a discussion of other matters in my testimony should not be taken
22 as an indication that I agree with all other aspects of intervenor testimony.

23
24 **Q4. Was your testimony prepared by you or under your direction?**

25 **A4. Yes.**

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1 **Q5. Are you sponsoring any exhibits in this proceeding?**

2 A5. Yes. I am sponsoring the following exhibits:

3	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
4	A-48	NN1	DTE DR MNSCDE-3.58(d)

5

6 **Q6. Were these exhibits prepared by you or under your direction?**

7 A6. Yes, they were.

8

9 **Alleged Bias in Model Results**

10 **Q7. AG-MN Witness Alvarez alleges 1898 & Co. and you are biased in your**
11 **modeling to favor capital spending and that you are not oriented to supporting**
12 **improvements in capital decision-making or capital spending optimization**
13 **because you are part of Burns & McDonnell, an engineering and construction**
14 **firm ¹. What is your response to this claim?**

15 A7. There is absolutely no such bias. 1898 & Co. applied data- and engineering-based
16 models and professional expertise to assist DTE Electric in identifying and
17 prioritizing investments to improve customer outcomes through enhancing and
18 improving distribution system reliability and resiliency and avoided future reactive
19 and restoration costs. As I will demonstrate below, the modeling and analysis are
20 carefully executed to not overestimate benefits or underestimate costs. Further, I'll
21 show, using a defensible data and risk-informed analysis, that even if benefits were
22 decreased or costs were increased that the investment BCA's main conclusions for
23 each program evaluated by 1898 & Co. are basically unchanged.

¹ Direct Testimony of Paul Alvarez, Page 34, line 23, Page 35, lines 1-20, Page 37, lines 15-21 and Page 38, lines 1-2

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1 Further, our modeling approach has been specifically designed to support
2 investment-decision analysis and not be biased. As shown in my revised direct
3 testimony, the modeling is comprehensive, evaluating the entire DTE Electric
4 system, customer-focused, asset centric, and data centric.² Our approach utilized a
5 discounted cash flow methodology calculating the resiliency, reliability, and risk
6 net present value (NPV) for each investment, what I consider the “gold standard”
7 for investment decision analysis. The model does not differentiate costs based on
8 their accounting classification, i.e., as expensed or capitalized.

9 Finally, as a Professional Engineer, I must abide by a strict code of ethics.³
10 That includes disclosing any conflicts of interest and making the best decisions for
11 society. I take that duty very seriously.

12

13 **Q8. What support does AG-MN Witness Alvarez provide for why 1898 & Co.,**
14 **yourself, and the modeling are biased?**

15 A8. AG-MN Witness Alvarez does not provide any direct support for this claim, rather
16 he alleges it based on four observations. First, that 1898 & Co. is a part of Burns &
17 McDonnell, an engineering and construction firm. He insinuates that 1898 & Co.
18 would only ever produce a positive economic investment since we are biased
19 toward capital construction. This ignores the fact that the 1898 & Co. evaluation
20 for PTMM and DA for all circuits showed many investments that do not currently
21 have benefits in excess of costs.⁴

22 The second and third observations are related to confidential material
23 provided in discovery. [REDACTED]

² U-21860 Revised Direct Testimony of Jason D. De Stigter Page JDDS-14, line 17 – JDDS- 16, line 5

³ National Society of Professional Engineers, *Code of Ethics*, July 2019,
<https://www.nspe.org/resources/ethics/code-ethics>, accessed September 8, 2025

⁴ Exh A-28 Sch R3 Program Benefit Cost Analysis Report Figures 1-2, 1-3, and 1-6

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⁵ NDA Workpaper DTE JDDS-R1 Non-Economic Spending by Program CONFIDENTIAL

⁶ Resume of Jason D. De Stigter Exh A-28 Sch R1

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Claims 1898 & Co.'s Model Understates Cost

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Q9. Several witnesses assert that 1898 & Co.'s modeling understates or underestimates the cost of investments causing the benefit cost ratio results to be significantly overstated. What specific claims are made? Which witness makes these claims?

21

22

23

⁷ U-21860 Rebuttal Testimony of Bill Chiu Page 21 Line 13 through Page 22 Line 14

⁸ Direct Testimony of Paul Alvarez, Page 35, lines 15-20

⁹ Direct Testimony of Paul Alvarez, Page 35, lines 16-18

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1 A9. The main argument for why these witnesses believe the 1898 & Co. BCA
2 understates costs relates to the use of a cash flow, or economic-based methodology
3 as opposed to a revenue requirements-based methodology for the project costs. AG-
4 MN Witness Alvarez claims that the cash flow-based approach as opposed to a
5 revenue requirements-based approach under estimates costs by nearly 30%.¹⁰ AG-
6 MN Witness Stephens also adopts AG-MN Witness Alvarez's position in general
7 and specifically on this point.¹¹ ABATE Witness Fitzhenry claims that a revenue
8 requirements-based approach would result in significantly higher costs and would
9 correspondingly lower the reported BCRs and demonstrate that projects are less
10 cost-effective than they appear from 1898 & Co's analysis.¹² CEO Witness
11 Volkmann, while acknowledging that the models applied rigorous and
12 sophisticated methodologies using a significant amount of DTE specific data¹³,
13 nonetheless expresses concerns that the 1898 & Co. model does not reflect the full
14 revenue requirements, but does not make direct claims as to his estimated impact
15 on BCRs.¹⁴

16 Specifically, AG-MN Witness Alvarez claims that the cash flow-based
17 approach does not include the interest on the debt, profits on equity, state and
18 federal income taxes, and property taxes that a revenue requirements-based
19 approach includes.¹⁵ ABATE Witness Fitzhenry and CEO Witness Volkmann
20 share the same concerns that these costs are not included. AG-MN Witness Alvarez
21 provides a simplified revenue requirements calculation of an example \$1 million
22 investment to calculate the revenue requirements costs on a discounted basis. His

¹⁰ Direct Testimony of Paul Alvarez, Page 38, lines 9-11

¹¹ Direct Testimony of Dennis Stephens, Page 17, lines 18-22 and Page 49, lines 7-9

¹² Direct Testimony of Colin Fitzhenry, Page 5 line 7 through Page 6 line 7

¹³ Direct Testimony of Curt Volkmann, Page 10 lines 8-10

¹⁴ Direct Testimony of Curt Volkmann, Page 11 line 14 through Page 12 line 4

¹⁵ Direct Testimony of Paul Alvarez, Page 38, lines 5-8

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1 analysis shows the revenue requirements-based cost is approximately \$1,296,000,
2 or 30% higher than a cash flow-based assessment.¹⁶

3

4 **Q10. Do you agree with the assessment by AG-MN Witnesses Alvarez,**
5 **ABATE Witness Fitzhenry, and CEO Witness Volkmann that a revenue**
6 **requirements-based approach rather than a cash-based approach should have**
7 **been utilized in performing the BCA as it would significantly increase costs**
8 **and lower the stated BCRs?**

9 A10. No, I do not agree with this conclusion. Employing a revenue requirements-based
10 approach within a BCA that utilizes a discounted cash flow-based methodology is
11 not necessary or appropriate for several reasons. First, utilizing a revenue
12 requirements-based approach is unnecessary because the impacts to the benefits
13 and costs components of a BCA would equally be impacted, causing no change in
14 the benefit cost ratio for an individual investment. Second, the cash flow-based
15 BCA methodology already appropriately includes or ignores the expenses they
16 claim would be added with a revenue requirements approach. Third, even in the
17 scenario where avoided customer outages are assumed to be an O&M expense and
18 taxes provide no benefits, the impact to the BCR calculation of a revenue
19 requirement basis would be minor relative to a cash flow basis. Fourth, the revenue
20 requirement calculation approach to evaluate an individual investment is not an
21 established standard, and differing approaches drive significantly different
22 conclusions, ranging from no impact to 10% impact.

¹⁶ Direct Testimony of Paul Alvarez, WP “Alvarez Table 1 Rate Impact per \$1M Investment.xlsx” supporting Table 1, Page 17, line 1

Line
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1 **Q11. Can you elaborate on your first reason why a revenue requirements-based**
2 **approach is not necessary or appropriate?**

3 A11. Yes, as stated above, it is unnecessary because the impacts are negligible to a BCA
4 evaluation as the benefits and costs components of a BCA would equally be
5 impacted, causing no change in the benefit cost ratio for an individual investment.
6 The impact of a revenue requirements-based approach compared with the cash
7 flow-based approach applied by 1898 & Co. hinges on how avoided customer
8 outages and taxes are treated in a revenue requirements-based evaluation. This
9 seems like an odd consideration as a revenue requirements-based evaluation
10 considered capital and O&M expenses, and monetized avoided customer outages
11 are neither of these. This is the main reason why 1898 & Co. employs a cash flow-
12 based methodology to perform the BCA and why a revenue requirements-based
13 approach is inappropriate for the purpose of the BCA. In the scenario where
14 avoided customer outage benefits are considered a capital expense, the BCR results
15 are no different between a cash flow or revenue requirements-based approach,
16 making Witnesses Alvarez, Fitzhenry and Volkmann's concerns moot. This is why
17 1898 & Co. does not consider it necessary to utilize a revenue requirements-based
18 methodology.

19 Additionally, taxes are ignored within the BCA as their impact should be
20 considered negligible. Conceptually, for each cost stream within a BCA a
21 corresponding benefit stream also needs to be incorporated. While the tax impacts
22 of an investment can be quantitatively estimated, the benefit of those taxes to
23 society and customers is far more challenging. Rather than estimating benefits of
24 taxes, the BCA effectively assumes any tax benefits are equal to costs, a
25 conservative assumption.

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1 Fundamentally, what is done to one side of the equation must be done to the
2 other side of the equation. These are important points that were ignored in the
3 critique of 1898 & Co.'s cash flow-based evaluation as opposed to a revenue
4 requirements-based approach. Incorporating a cost stream while not incorporating
5 a corresponding benefit stream biases the BCA inappropriately.

6

7 **Q12. Your second reason why a revenue requirements-based approach is not**
8 **necessary or appropriate is because the cash flow-based BCA already**
9 **appropriate includes or ignores costs that a revenue requirements-based**
10 **approach is presumed to include. Can you please explain?**

11 A12. Yes. A key difference between the two approaches is the timing of costs and how
12 they are considered in the present value calculation. In a cash flow-based approach,
13 costs are shown in the year they occurred, very simple to understand. In a revenue
14 requirements-based approach, capital expenses are assumed to be financed over
15 time, while O&M expenses are shown in the year they occur. As it relates to the
16 BCA, each approach includes or ignores expenses, they may just be called
17 something different. For instance, depreciation expense in a revenue requirements
18 evaluation is called the investment expense in a cash flow-based model. For
19 investment decision analysis, the discount rate employed within the cash flow-
20 based model implies a hurdle to pay for the interest on debt and profits on equity.
21 When employing a revenue requirement-based approach for the cost of an
22 investment, the weighted average cost of capital, which is based on the debt/equity
23 ratio and the cost of debt and equity, negates any differences on a present value
24 basis between a cash flow and revenue requirements-based evaluation. Stranded
25 costs are already considered within the benefits portion of the evaluation. Taxes are

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1 ignored, as discussed above, within the BCA as their impact should be considered
2 negligible. Therefore, the concern that these cost streams are not included in the
3 evaluation is unwarranted, presumably driven by a misunderstanding of discounted
4 cash flow methodology.

5

6 **Q13. Your third reason why a revenue requirements-based approach is not**
7 **necessary or appropriate is because even with the assumption that some costs**
8 **are considered O&M or provide no benefits that the difference on the BCA**
9 **results are minor. Can you please elaborate?**

10 A13. Yes. The reason why the difference is minor to the BCA is that for most
11 investments there are avoided future costs. So while the investment costs would go
12 up, so would the benefits, muting the net impact of performing a revenue
13 requirements-based approach. In the case of PTMM, avoided future capital costs
14 on a present value basis are approximately 88% of investment costs for the
15 groundline sub-program and 69% for the pole-top sub-program²². I present analysis
16 on the impact to the BCA for PTMM further below in my testimony. For
17 distribution automation, there are no avoided future capital costs, however as I will
18 present below even in that scenario the impacts of a revenue requirement approach
19 are minor on the benefit cost analysis.

20

21 **Q14. Your fourth reason why a revenue requirements-based approach is not**
22 **necessary or appropriate is because the approach to evaluate an individual**
23 **investment is not an established standard and results in different estimates.**
24 **Can you please explain your reasoning?**

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1 A14. An accurate revenue requirements assessment for a single investment requires that
2 the incremental impact of the investment decision be evaluated on the Company's
3 balance sheet and income statements, to accurately estimate the taxation impacts.
4 This further requires assumptions on the order investments will be made. In other
5 words, the incremental revenue requirement impact of Project 1 is dependent on the
6 assumption if Project 2 will be done and if Project 2 is assumed to be executed
7 before or after Project 1. As this little example shows, an accurate revenue
8 requirements assessment for each individual investment, noting that thousands
9 were completed, is nearly impossible to estimate accurately and values would vary
10 significantly depending on assumptions. In the absence of such information,
11 revenue-requirement modelling of an individual investment is based on
12 assumptions for the investment order of a project. One approach is to assume each
13 project is the last project added, called an incremental approach, while another
14 approach is that the project is in the middle of all other investments, called a
15 comprehensive approach. There are also differences in how taxation and project
16 timing within a year, January 1 or July 1 install, should be applied in this situation.
17 These differences in approaches on how to consider the order of an individual
18 investment against all other investments causes significant differences in the
19 revenue requirement present value difference of an investment compared to a cash
20 flow-based difference. Company Witness Lepczyk performed example calculations
21 of these two approaches as described in his Rebuttal testimony on pages 7-9. He
22 shows that an incremental approach produces approximately 10% increase in cost
23 of a revenue requirement approach over a cash flow-based approach, while the
24 comprehensive approach is as low as a 2% increase in cost. Because 1898 & Co.
25 evaluated thousands of projects, assuming the incremental approach for all of them

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1 is inappropriate, the comprehensive approach is more appropriate for the BCA. As
2 the comprehensive approach produces a negligible difference, noting that this is
3 based on the assumption that avoided customer outage benefits are O&M and taxes
4 provide no benefits, utilizing a revenue requirements-based approach is
5 unnecessary, providing negligible benefits with significant costs to utilize.

6

7 **Q15. While you have just demonstrated that a revenue requirements-based**
8 **approach is inappropriate and unnecessary, do you have any concerns with**
9 **the application of AG-MN Witness Alvarez's revenue requirements**
10 **assessment?**

11 A15. Yes, I have several concerns. The first is the accuracy of AG-MN Witness
12 Alvarez's simplified revenue requirements-based calculation. It includes inaccurate
13 estimates and a flawed basis for understanding the incremental impact of an
14 investment. Second, AG-MN Witness Alvarez only applied the revenue
15 requirements methodology to the cost portion of the benefit cost analysis, ignoring
16 how this approach would impact the benefit side of the evaluation. Third, no
17 analysis was presented that shows the impact of the approach on benefit cost results.
18 Rather the overarching claim assumes the BCA is fundamentally flawed because a
19 revenue requirements-based approach was not performed. Fourth, with respect to
20 the Grid Automation Telecommunication BCA, AG-MN Witness Alvarez does not
21 equally apply the revenue requirements-based approach to all investment
22 alternatives.¹⁷ This results in a significant flaw in his analysis, causing him to
23 recommend a higher life-cycle cost alternative for customers. I will now address
24 each of these concerns in more detail.

¹⁷ Direct Testimony of Paul Alvarez, Page 47-48, Table 3

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1 **Q16. Can you elaborate on your first concern related to the inaccuracies of AG-MN**
2 **Witness Alvarez's simplified revenue requirements-based calculation to**
3 **justify why 1898 & Co.'s costs are 30% low?**

4 A16. Yes. Witness Lepczyk reviewed AG-MN Witness Alvarez's simplified revenue
5 requirements calculation and noted several deficiencies and errors. Witness
6 Lepczyk noted three minor errors, book depreciation exceeding 100%, improper
7 application of accelerated depreciation, and incorrect calculation of deferred taxes,
8 and one large error, utilizing a post-tax WACC when a pre-tax WACC is
9 appropriate.¹⁸ After correcting these errors, AG-MN Witness Alvarez's simplified
10 revenue requirement's incremental assumed approach shows a 10% higher level
11 than a cash flow-based approach.¹⁹ Further, Witness Lepczyk noted that AG-MN
12 Witness Alvarez did not use capitalization ratio more in line with the company's
13 reported financial values, the comprehensive approach, which would decrease the
14 revenue requirement incremental value above a cash flow-based approach to just
15 2%.²⁰

16
17 **Q17. Can you elaborate on your second concern related to misapplication of the**
18 **revenue requirement approach only to the cost portion of the analysis.**

19 A17. AG-MN Witness Alvarez's application of a revenue requirements-based approach
20 on the benefit cost analysis only applies to the investment part of the BCA. For
21 consistency, it should also apply to the benefits part of the evaluation. As outlined
22 in my revised direct testimony and in the 1898 & Co. report, the benefit evaluation
23 includes avoided future reactive and restoration costs and avoided customer outages

¹⁸ Rebuttal Testimony of Lepczyk, Page 8, lines 21-24, Page 9, lines 1-6

¹⁹ Rebuttal Testimony of Lepczyk, Page 9, line 10-11

²⁰ Rebuttal Testimony of Lepczyk, Page 9, lines 6-12

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1 that are monetized utilizing the DOE ICE Calculator.²¹ For accuracy, the same
2 approach should be used for both the benefits and costs side of the evaluation. AG-
3 MN Witness Alvarez essentially advocates for utilizing a cash flow basis for the
4 numerator and a different revenue requirements basis for the denominator. This
5 mixing of approaches within the benefit-cost analysis is inappropriate and biases
6 the evaluation by increasing the cost part of the equation and leaving the benefits
7 portion unchanged.

8

9 **Q18. With regard to your third concern, how would this revenue requirements-**
10 **based approach impact the BCR results of the PTMM program assuming**
11 **customer outage benefits are treated as O&M and taxes provide no benefits?**

12 A18. As I've discussed above, if taxes are considered in the benefits component of the
13 BCA or if the avoided customer outages are considered a capital, the revenue
14 requirements-based methodology would produce the same BCR results as a cash
15 flow-based approach. However, assuming customer outages are considered an
16 O&M expense and taxes do not provide benefits, the revenue requirements
17 calculation only applies to the avoided future cost-based benefits of the PTMM
18 program. Table 1 and Table 2 below shows the impact to the BCR results for the
19 PTMM groundline and pole-top sub-programs, respectively²². These tables are
20 based on assuming revenue requirements costs are 10% higher than a cash flow-
21 basis, the conservative assumption.

²¹ U-21860 Revised Direct Testimony of Jason D. De Stigter Page JDDS-6 line 17

²² NDA Workpaper DTE JDDS-R2 Cash Flow vs Rev Requirements-Based Approach CONFIDENTIAL, "PTMM Results Summary" tab

Line

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**Table 1: PTMM Groundline BCR Impacts:
Cash Flow vs. Revenue Requirements-based Approach**

BCR Range	Circuit Count		Weighted Average BCR	
	Cash Flow Basis	Rev Req Basis	Cash Flow Basis	Rev Req Basis
x < 1		11		0.995
1 ≤ x < 2	1,824	1,916	1.43	1.41
2 ≤ x < 3	646	594	2.39	2.38
3 ≤ x < 4	169	135	3.41	3.42
4 ≤ x < 5	46	35	4.39	4.25
5 ≤ x	18	12	5.65	5.42
Total	2,703	2,703	1.71	1.64

3

4

**Table 2: PTMM Pole-top BCR Impacts:
Cash Flow vs. Revenue requirements-based Approach**

BCR Range	Circuit Count		Weighted Average BCR	
	Cash Flow Basis	Rev Req Basis	Cash Flow Basis	Rev Req Basis
x < 1		16		0.99
1 ≤ x < 2	897	968	1.54	1.52
2 ≤ x < 3	580	605	2.46	2.48
3 ≤ x < 4	404	380	3.41	3.45
4 ≤ x < 5	265	263	4.46	4.44
5 ≤ x	428	342	6.66	6.50
Total	2,574	2,574	2.81	2.63

5 The 10% higher basis for the revenue requirements approach causes only 11
6 circuits, or 0.41% of all positive BCR circuits, to have their benefit cost ratio go
7 below 1 for the groundline sub-program and 16 circuits, or 0.62% of positive BCR
8 circuits, for the pole-top sub-program. As shown in the table, these less than 1 BCR
9 circuits with the revenue requirements approach have a weighted average BCR of
10 0.995 for groundline and 0.99 for pole-tops, extremely close to 1.0. Additionally,
11 the tables also show that the aggregate impact to the BCR results is minor with the
12 average groundline BCR decreasing by 4.01% and the pole-top BCR decreasing by
13 6.98%. This shows that the impact of a revenue requirements-based approach,
14 assuming customer outages are considered O&M and taxes provide no benefits, on

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1 1898 & Co.'s BCA approach are minimal. The claims that this approach would
2 significantly impact the PTMM BCA are just not supported based on this analysis.

3

4 **Q19. The distribution automation program BCA includes only future avoided**
5 **customer outages²³, how does this revenue requirements-based approach**
6 **impact the BCA results assuming customer outage benefits are treated as**
7 **O&M and taxes provide no benefits?**

8 A19. Table 3 below shows the impact to the BCR results for the distribution automation
9 program, assuming revenue requirements costs are 10% higher than a cash flow-
10 basis.

11

Table 3: DA BCR Impacts:
Cash Flow vs. Revenue requirements-based Approach ²⁴

BCR Range	Circuit Count		Weighted Average BCR	
	Cash Flow Basis	Rev Req Basis	Cash Flow Basis	Rev Req Basis
x < 1		61		0.95
1 <= x < 2	445	428	1.44	1.42
2 <= x < 3	213	219	2.49	2.47
3 <= x < 4	143	136	3.48	3.45
4 <= x < 5	75	62	4.41	4.50
5 <= x	314	284	10.50	10.03
Total	1,190	1,190	4.37	3.97

12

13 Even without avoided capital expenses benefits, the 10% higher basis for the
14 revenue requirements approach causes only 61 circuits, or 5.13% of all positive
15 BCR circuits, to have their benefit cost ratio go below 1. As shown in the table,
16 these less than 1 BCR circuits with the revenue requirements approach have a

²³ Exh A-28 Sch R3 Program Benefit Cost Analysis Report Figure 4-13 "Distribution Automation Program BCR Summary"

²⁴ NDA Workpaper DTE JDDS-R2 Cash Flow vs Rev Requirements-Based Approach CONFIDENTIAL, "DA Results Summary" tab

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1 weighted average BCR of 0.95. When considering the conservative nature of
2 benefits assessment as outlined in my revised direct testimony²⁵, these projects
3 should still be considered as providing benefits in excess of costs for customers.
4 Additionally, the tables also show that the aggregate impact on the BCR results is
5 minor with the average BCR decreasing by 10%. This further shows that the impact
6 of a revenue requirements-based approach, assuming customer outages are
7 considered O&M and taxes provide no benefits on 1898 & Co.'s BCA approach is
8 minimal. Again, the claims that this approach would significantly impact the
9 Distribution Automation BCA are just not supported based on this analysis.

10

11 **Q20. For your fourth concern, you mentioned that AG-MN Witness Alvarez did not**
12 **equally apply the revenue requirements-based approach to evaluated**
13 **communication alternatives. Can you explain your concern?**

14 A20. Yes, with respect to the Grid Automation Telecommunication BCA, AG-MN
15 Witness Alvarez inappropriately applies a revenue requirements-based approach to
16 the Private LTE/Fiber alternative while still utilizing a cash flow-based
17 methodology for the Public LTE alternative to compare their life-cycle costs. Based
18 on this, he inaccurately concludes that Public LTE is the least cost alternative.

19

20 **Q21. Can you please present AG-MN Witness Alvarez's analysis to better**
21 **understand this misapplication?**

22 A21. Yes, while AG-MN Witness Alvarez shows his analysis confidentiality, the
23 information is in the public record in my direct testimony. Table 4 shows the total
24 life-cycle cost results (in 2025 millions) of expanded use case scenarios evaluated

²⁵ Case No. U-21860 Revised Direct Testimony of Jason D. De Stigter Page JDDS-31 line 14 – JDDS-32 line 2

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1 by 1898 & Co. for the cash flow-based evaluation and Witness Alvarez's revenue
2 requirements adjusted analysis.

3

4

Table 4: Public LTE and Private LTE / Fiber PV Cost Analysis Summary²⁶

Description	Cash Flow Analysis ²⁷		Alvarez Rev. Req. Analysis	
	Public LTE	Private LTE / Fiber	Public LTE	Private LTE / Fiber
Edge Device Upfront Investment	\$23.5	\$107.4	\$23.5	\$134.2
Edge Device Life-cycle Replacements	\$130.5	\$105.7	\$130.5	\$132.2
Edge Device Life-cycle Obsolescence Replacements Risk	\$209.5	\$0.0	\$209.5	\$0.00
Cellular Carrier Fees	\$227.1	\$0.0	\$227.1	\$0.00
Other Maintenance Costs	\$203.3	\$204.9	\$203.3	\$204.9
Telecomm System Infrastructure Upgrades: Towers	\$0.0	\$26.7	\$0.0	\$33.3
Telecomm System Infrastructure Upgrades: Fiber Backhaul	\$0.0	\$38.2	\$0.0	\$47.8
Telecomm System Infrastructure Upgrades: Fiber Tabs	\$0.0	\$11.0	\$0.0	\$13.7
Telecomm System Infrastructure Upgrades: Electronic Sites	\$0.0	\$41.4	\$0.0	\$51.8
Telecomm System Infrastructure Upgrades: Backend	\$0.0	\$171.8	\$0.0	\$214.7
Total Life-Cycle Investment Costs	\$793.9	\$707.1	\$793.9	\$832.6

5 The cash flow-based evaluation shows that the Private LTE / Fiber
6 alternative provides the lowest life-cycle costs for DTE Electric customers, \$86.8
7 million less than the Public LTE equivalent alternative. AG-MN Witness Alvarez

²⁶ Workpaper DTE JDDS-R3 Grid Automation Revenue Requirements²⁷ Exhibit A-28, Schedule R3, Program Benefit Cost Analysis Report, page 123, Table 4-2

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1 assumed the revenue requirements-based approach would include a 25% cost
2 premium for customers.²⁸ As shown in the table, this cost premium was only
3 applied to the capital expense line items for the Private LTE / Fiber scenario. For
4 the Public LTE scenario, this same cost premium was not applied to the same
5 capital expense line items as the Private LTE / Fiber scenario, specifically the edge
6 device investments that DTE would need to make with this scenario. It is based on
7 this analysis that AG-MN Witness Alvarez concludes, “that Public Cellular is the
8 way to go.”²⁹ This misapplication of the revenue requirements-based approach to
9 one scenario and not the other produces inaccurate life-cycle cost estimates, biases
10 the results, and incorrectly drives the wrong investment recommendation by AG-
11 MN Witness Alvarez.

12

13 **Q22. What are the life-cycle cost results of both scenarios when the revenue**
14 **requirements-based approach is applied to both scenarios?**

15 A22. Table 5 below shows the scenario results when a revenue requirements-based
16 approach is applied to both alternatives (in 2025 millions). The table includes the
17 more accurate 10% revenue requirements value as well as the 25% assumption
18 utilized by AG-MN Witness Alvarez.

²⁸ Direct Testimony of Paul Alvarez, Page 47, lines 16-17

²⁹ Direct Testimony of Paul Alvarez, Page 48, lines 4-5

Table 5: Public LTE and Private LTE / Fiber Revenue Requirement Approach³⁰

Description	10 Percent		25 Percent	
	Public LTE	Private LTE / Fiber	Public LTE	Private LTE / Fiber
Edge Device Upfront Investment	\$25.8	\$118.1	\$29.3	\$134.2
Edge Device Life-cycle Replacements	\$143.5	\$116.3	\$163.1	\$132.2
Edge Device Life-cycle Obsolescence Replacements Risk	\$230.5	\$0.00	\$261.9	\$0.00
Cellular Carrier Fees	\$227.1	\$0.00	\$227.1	\$0.00
Other Maintenance Costs	\$203.3	\$204.9	\$203.3	\$204.9
Telecomm System Infrastructure Upgrades: Towers	\$0.00	\$29.3	\$0.00	\$33.3
Telecomm System Infrastructure Upgrades: Fiber Backhaul	\$0.00	\$42.0	\$0.00	\$47.8
Telecomm System Infrastructure Upgrades: Fiber Tabs	\$0.00	\$12.1	\$0.00	\$13.7
Telecomm System Infrastructure Upgrades: Electronic Sites	\$0.00	\$45.6	\$0.00	\$51.8
Telecomm System Infrastructure Upgrades: Backend	\$0.00	\$189.0	\$0.00	\$214.7
Total Life-Cycle Investment Costs	\$830.2	\$757.3	\$884.8	\$832.6

2 As Table 5 shows, in either revenue requirements scenario, the Private LTE
3 / Fiber scenario has the lower life-cycle cost, by approximately 10% for the 10%
4 scenario and 6 percent for the 25% scenario. This shows that the Private LTE / Fiber
5 scenario is the preferred alternative for customers. As it relates to performing a cash
6 flow-based evaluation or a revenue requirements-based evaluation, it should be
7 noted that the investment decision has not changed.

³⁰ Workpaper DTE JDDS-R3 Grid Automation Revenue Requirements

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1 **Q23. Are there any other concerns expressed by AG-MN Witness Alvarez related**
2 **to underestimating investment costs?**

3 A23. Yes, AG-MN Witness Alvarez claims the distribution automation modeling
4 underestimates the costs of tie lines for distribution automation.³¹ Specifically, AG-
5 MN Witness Alvarez cites a cost of \$149,000 for existing tie upgrades and states
6 that, in his experience, the cost of upgrades can be much higher.³² He also states
7 that the Company's BCA assumes only 34 new tie lines will need to be built,
8 implying more will need to be constructed.³³

9
10 **Q24. What is your response to AG-MN Witness Alvarez's concern and claims?**

11 A24. His concerns are based on a misunderstanding of the BCA performed for
12 distribution automation and the detailed cost evaluation provided in discovery. The
13 \$149,000 existing tie upgrade cost is for replacing the existing manual switch with
14 a recloser. This same cost is used for all reclosing devices. As noted in the 1898 &
15 Co. report, the modeling identified small conductor on each circuit backbone and
16 the modeling also identified which small wire conductor likely requires a "full
17 rebuild" or a "partial rebuild", and assumed 50% would need to be reconductored
18 only for the "partial rebuild" designation.³⁴ I believe this is the cost AG-MN
19 Witness Alvarez is referencing. With respect to the cost of new tie lines, 1898 &
20 Co. incorporated this potentially high cost into the evaluation, that is why only 34
21 circuits were selected. Most of the circuits already had existing tie lines and needed
22 replacement of manual switches with reclosers and the addition of new reclosers.

³¹ Direct Testimony of Paul Alvarez, Page 41, lines 1-16

³² Ibid Lines 7-9

³³ Ibid, Lines 11-13

³⁴ Exh A-28 Sch R3 Program Benefit Cost Analysis Report, Page 96 of 135

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1 Some circuits also included conductor upgrades. Based on these facts, the costs
2 have not been underestimated in the BCA for the DA program.

3

4 **Claims 1898 & Co.'s Model Overstates Benefits**

5 **Q25. Several witnesses assert that 1898 & Co.'s modeling overstates the benefits of**
6 **investments. Can you provide an overview of their various claims on why**
7 **benefits are overstated?**

8 A25. The claims that benefits are overstated are based on five assertions. First, AG-MN
9 Witnesses Alvarez and Stephens have general concerns that the use of the ICE tool
10 and its application within 1898 & Co.'s model overstates the dollar value of
11 reliability improvements.³⁵ Second, and related to the first concern, AG-MN
12 Witnesses Alvarez and Stephens claim the benefits are overstated with respect to
13 1898 & Co.'s use of a 3.0 multiplier for critical customers.³⁶ ABATE Witness
14 Fitzhenry also shares in this concern.³⁷ Third, AG-MN Witnesses Alvarez and
15 Stephens claim that since the reliability data used to perform the DA benefit cost
16 analysis was not normalized to factor in the vegetation management and pole
17 inspection programs that the distribution automation program benefits are
18 overstated.³⁸ AA Witness Stults shares this concern, specifically that the reliability
19 data does not include the impact of the recent tree trimming surge.³⁹ Fourth,
20 ABATE Witness Fitzhenry claims that since the Distribution Automation BCA was
21 performed utilizing 2019 through 2023 data and it does not include 2024, which
22 was a good reliability year, that the assessment overstates customer outages by

³⁵ Direct Testimony of Paul Alvarez, Page 38, lines 17-18

³⁶ Direct Testimony of Paul Alvarez, Page 38, lines 18-21

³⁷ Direct Testimony of Colin T. Fitzhenry, Page 9, lines 5-14

³⁸ Direct Testimony of Paul Alvarez, Page 41, line 19 – Page 42, line 12 & Direct Testimony of Dennis Stephens, Page 17, line 18 – Page 18, line 10

³⁹ Direct Testimony of Dr. Melissa Stults, Page 12 Line 18 – Page 13 Line 8.

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1 approximately 60%, inflating benefits.⁴⁰ Fifth, AG-MN Witness Stephens claims
2 the customer outage improvements from the modelling are greater than the
3 customer outages due to equipment failures.⁴¹ He utilizes this observation to claim
4 the model is not valid and biased toward capital spending rather than investment
5 decision analysis.⁴²

6

7 **Q26. Can you provide additional context relative to AG-MN Witness Alvarez's first**
8 **claim that the ICE tool and its application within the 1898 & Co. model**
9 **overstates the value of reliability improvements?**

10 A26. AG-MN Witness Alvarez makes a general statement that he believes the ICE tool
11 overstates reliability improvements.⁴³ He rests this belief on the notion that
12 residential reliability improvements amount to 9% of the total reliability
13 improvements value in the ICE tool's outputs and that commercial and industrial
14 customers account for most of the reliability improvement value.⁴⁴ He does not
15 provide supporting documentation for this assessment. Further, I am unclear of its
16 basis. Without supporting documentation and analysis, his conclusion that the ICE
17 tool overstates benefits is simply speculation.

18

19 **Q27. Can you provide an overview of AG-MN Witness Alvarez's second claim that**
20 **the BCA model benefits are overstated in how critical customers are evaluated**
21 **within the 1898 & Co. modeling?**

⁴⁰ Direct Testimony of Colin T. Fitzhenry, Page 8, lines 1-8

⁴¹ Direct Testimony of Dennis Stephens, Page 49 line 21 – Page 50 line 3

⁴² Direct Testimony of Dennis Stephens, Page 50 lines 3-7

⁴³ Direct Testimony of Paul Alvarez, Page 38, lines 17-18

⁴⁴ Direct Testimony of Paul Alvarez, Page 40, lines 12-15

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1 A27. AG-MN Witness Alvarez's argument centers on the assumptions for the cost of
2 interruptions for DTE Electric's critical customers. AG-MN Witness Alvarez states
3 the model utilizes the Interruption Cost Estimate ("ICE") Calculator and a
4 multiplier of 3 for critical customers over small commercial customers.⁴⁵ AG-MN
5 Witness Alvarez states that both he and AG-MN Witness Stephens "know of no
6 support or justification for this valuation adjustment."⁴⁶ ABATE Witness Fitzhenry
7 also makes this claim.⁴⁷ Additionally, AG-MN Witness Alvarez also argues the
8 benefits for these types of customers should be lower since they already have
9 installed back-up generation.⁴⁸

10

11 **Q28. What response do you have to the argument that the multiplier of 3 over-**
12 **estimates the BCA and has no basis?**

13 A28. I disagree with this assertion for three reasons. First, the BCA reflects the elevated
14 importance of critical customers in the outage restoration process. The
15 identification of critical customers is a responsibility undertaken by DTE Electric,
16 based on the recognition of these customers' high priority status during power
17 restoration after an outage. These are customers for whom power restoration is of
18 utmost importance due to their vital roles in society or the economy. Examples of
19 critical customers identified by DTE include hospitals, senior centers, and essential
20 infrastructure like the Detroit Water and Sewage Department (DWSD). The
21 valuation of these critical customers requires a different approach due to their
22 unique status and importance.

⁴⁵ Direct Testimony of Paul Alvarez, Page 39, lines 5-7

⁴⁶ Direct Testimony of Paul Alvarez, Page 39, lines 7-8

⁴⁷ Direct Testimony of Colin Fitzhenry, Page 9, lines 4-14

⁴⁸ Direct Testimony of Paul Alvarez, Page 39, lines 9-15

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Second, the multiplier of 3 does have a statistical basis within the ICE Calculator. In our evaluation, we leveraged the 95th percentile, P95, of the Small C&I customer category as a suitable proxy for the value of a critical customer. This was described during the technical conference. Table 6 below shows the ratio of the P95 customer value relative to the mean for several regions. Based on the range of values, 1898 & Co. assumed a value of 3, well below the ratio of the P95 to the mean. For the other customer categories, we used the mean value provided by the ICE Calculator.

Table 6: Small C&I ICE Calculator Regional Multipliers⁴⁹

Region	Mean	Standard Deviation	P95%	Ratio (P95 /Mean)
Midwest	\$776	\$2,240	\$3,133	4.04
Northwest	\$388	\$1,480	\$1,597	4.12
Southeast	\$787	\$2,645	\$3,685	4.68
Southwest	\$924	\$2,748	\$4,393	4.75
West	\$746	\$2,162	\$3,476	4.66

Third, the BCA conclusions for each of the investments are unchanged if a lower multiplier were to be utilized. Table 7, Table 8, and Table 9 below show the impact to the BCA if the 3.0 multiplier was not used for critical customers⁵⁰. As these tables show, very few circuits, approximately 3.0%, drop below a BCR of 1 with this change and even those circuits still average a BCR above 0.9. When considering that other benefit streams, like safety, have not been included in the evaluation, it is reasonable to assume that these projects would still provide benefits in excess of costs for customers even without the 3.0 multiplier. The tables also

⁴⁹ The “Ratio” column is calculated with the following formula: *Ratio* = *P95%* / *Mean*. All other columns (Region, Mean, Standard Deviation, and P95%) are sourced from Table 4-2, page 30, https://eta-publications.lbl.gov/sites/default/files/interruption_cost_estimate_guidebook_final2_9july2018.pdf, accessed September 8, 2025

⁵⁰ NDA Workpaper DTE JDDS-R4 Original vs No 3.0 Multiplier CONFIDENTIAL, “Results Summary” tab

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- 1 show relatively minimal impact on the average BCR for all the investments,
- 2 decreasing anywhere from 2.6% to 5.6%.
- 3

Table 7: PTMM Groundline BCR Impacts: Excluding 3.0 Multiplier for Critical Customers

BCR Range	Circuit Count		Weighted Average BCR	
	Original Results	No. 3.0 Multiplier	Original Results	No. 3.0 Multiplier
x < 1		18		0.99
1 <= x < 2	1,824	1,893	1.43	1.42
2 <= x < 3	646	592	2.39	2.38
3 <= x < 4	169	151	3.41	3.42
4 <= x < 5	46	36	4.39	4.31
5 <= x	18	13	5.65	5.61
Total	2,703	2,703	1.71	1.67

4

Table 8: PTMM Pole-top BCR Impacts: Excluding 3.0 Multiplier for Critical Customers

BCR Range	Circuit Count		Weighted Average BCR	
	Original Results	No. 3.0 Multiplier	Original Results	No. 3.0 Multiplier
x < 1		26		0.98
1 <= x < 2	897	939	1.54	1.53
2 <= x < 3	580	593	2.46	2.46
3 <= x < 4	404	393	3.41	3.41
4 <= x < 5	265	256	4.46	4.43
5 <= x	428	367	6.66	6.53
Total	2,574	2,574	2.81	2.70

5

Table 9: DA BCR Impacts: Excluding 3.0 Multiplier for Critical Customers

BCR Range	Circuit Count		Weighted Average BCR	
	Original Results	No. 3.0 Multiplier	Original Results	No. 3.0 Multiplier
x < 1		36		0.94
1 <= x < 2	445	435	1.44	1.42
2 <= x < 3	213	217	2.49	2.48
3 <= x < 4	143	140	3.48	3.44
4 <= x < 5	75	67	4.41	4.44
5 <= x	314	295	10.50	10.22
Total	1,190	1,190	4.37	4.12

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1 **Q29. What about AG-MN Witness Alvarez’s concerns that many of these customers**
2 **have backup generation and should have a lower value than the average C&I**
3 **customer?**

4 A29. This concern does not have merit and is overstated. While true that backup
5 generation mitigates some of the impacts of an outage, it does not mitigate the total
6 impact. Backup generators are typically sized to only meet critical loads; while
7 some functions will continue, it is not business as usual. Reductions in the level of
8 service will need to be made while operating on backup generation power.
9 Therefore, backup generators mitigate only a portion of the disruption for short-
10 duration outages; for longer outages associated with strong storm events, the
11 mitigation effectiveness is significantly less. This is due to both failure to start and
12 failure to continue to operate for the outage duration.⁵¹ Additionally, backup
13 generators require timely maintenance activities to achieve their best reliability, and
14 these activities might be overlooked and not completed.

15

16 **Q30. How do you respond to the third claim by AG-MN Witnesses Alvarez,**
17 **Stephens, and ABATE Witness Fitzhenry that Distribution Automation**
18 **benefits are significantly overstated because the benefits calculations are based**
19 **on reliability data that was not normalized to factor in the PTMM and**
20 **Vegetation Management programs?**

21 A30. I do not agree with this claim. While it is true that the historical reliability data used
22 to perform the distribution automation was not normalized for these two programs,
23 the extent of the impact on the distribution automation BCA is exaggerated. In fact,

⁵¹ Jeffrey Marqusee, *Emergency Diesel Generator Reliability and Installation Energy Security*, National Renewable Energy Laboratory Technical Report NREL/TP-5C00-76553 published April 2020; <https://www.nrel.gov/docs/fy20osti/76553.pdf>

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1 their claims are not based on any meaningful analysis of the historical reliability
2 data to understand if normalization would produce meaningful changes in the BCA
3 results. As I will show below, when factoring in the normalization, the BCA results
4 for the Distribution Automation program do not meaningfully change.

5

6 **Q31. How did 1898 & Co. normalize the historical outage data for the PTMM and**
7 **Tree Trimming Programs?**

8 A31. 1898 & Co. used the PTMM avoided customer outage CMI benefits by circuit⁵²
9 and decreased the historical equipment outages as appropriate. 1898 & Co. also
10 decreased vegetation-based⁵³ outages by approximately 28%⁵⁴, the average
11 improvement for a 5-year cycle, for years in which the vegetation program had not
12 been completed.

13

14 **Q32. What are the results of this reliability data normalization analysis on the**
15 **Distribution Automation BCA?**

16 A32. Table 10 below shows the impact to the distribution automation BCA assuming
17 both PTMM and Vegetation Management have been executed on all circuits before
18 distribution automation is implemented⁵⁴. As this table shows, only 158, or 13.2%,
19 of the 1,190 positive BCR circuits drop below a 1.0 BCR. While these circuits have
20 a BCR less than 1, their average BCR is 0.85. For the 1,190 circuits, the
21 normalization to include PTMM and Vegetation Management before DA decreases
22 the population's BCR from 4.37 to 3.36. This shows AG-MN Witness Alvarez,
23 AG-MN Witness Stephens, and ABATE Witness Fitzhenry's claims that this lack

⁵² See Figure 4-1 and 4-4 from the Exhibit A-28 Schedule R3

⁵³ Vegetation inside and outside of ROW and Wind based cause codes

⁵⁴ NDA Workpaper DTE JDDS-R5 DA Assuming PTMM and ETPP Analysis CONFIDENTIAL

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of normalization is a major deficiency of the BCA to be exaggerated. Further, this analysis shows that the overall DA BCA would still be expected to provide benefits in excess of costs for customers and delays in execution only cause customers to experience more outages.

Table 10: DA BCA Impact: Assuming PTMM and Vegetation Management Completed Before DA

BCR Range	Circuit Count		Weighted Average BCR	
	Original Results	PTMM & Veg. Before DA Scenario	Original Results	PTMM & Veg. Before DA Scenario
x < 1		158		0.85
1 <= x < 2	445	418	1.44	1.43
2 <= x < 3	213	207	2.49	2.46
3 <= x < 4	143	109	3.48	3.45
4 <= x < 5	75	76	4.41	4.49
<= x	314	222	10.50	9.59
Total	1,190	1,190	4.37	3.36

Additionally, it is improper to assume that these 158 circuits would not provide benefits in excess of costs for customers. Firstly, this evaluation is a “what-if” evaluation used to rebut claims that the 1898 & Co. analysis exaggerates benefits. A more appropriate analysis to understand the three investment programs together on a circuit basis and evaluated the combined benefit cost ratio. Based on my experience, with an average BCR of 0.85, the combined BCR of the three together would be greater than 1. Second, given the conservative nature of the BCA and that other benefits streams, like reduced restoration time related to circuit patrols and restore-before-repair opportunities, were not considered in the evaluation it is reasonable to assume that these 158 circuits would still provide benefits in excess of costs for customers.

Q33. Regarding the fourth claim that the model overstates benefits, do you agree with ABATE Witness Fitzhenry that because the Distribution Automation

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1 **BCA did not include data from 2024 that the benefits assessment is overstated**
2 **by approximately 60%?**

3 A33. I completely disagree with this conclusion, as it is based on a flawed assumption
4 regarding future outages. For clarity, at the time 1898 & Co. performed the benefits
5 analysis, 2024 reliability data was not available. 1898 & Co. utilized data from 2019
6 through 2023. The basis for ABATE Witness Fitzhenry's conclusions is an
7 assumption that 2024 reliability data is "more reflective of the Company's current
8 reliability performance."⁵⁵ Essentially, ABATE Witness Fitzhenry's assumption is
9 that the next 20 years of outages, the time horizon for the distribution automation
10 BCA, will be similar to 2024. This is an extremely flawed assumption. First, it is
11 based on an evaluation of SAIDI with Major Event Day (MED) Outages. Major
12 Event Day outages, as the name suggests, are mainly driven by major weather
13 events. While I have not done the analysis on major weather events, I suspect 2024
14 was a good reliability year because it had fewer and/or less intense events than
15 previous years. His own table, shown below for ease of reference, demonstrates the
16 fallacy of this conclusion.

⁵⁵ Direct Testimony of Colin T. Fitzhenry, Page 8, lines 5-6

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Figure 1: ABATE Witness Fitzhenry's DTE SAIDI with MED Table Reference⁵⁶

TABLE CTF-1	
<u>SAIDI with MEDs 2019-2024</u>	
Period	SAIDI with MED (Minutes)
2019	466.3
2020	351.8
2021	927.4
2022	583.9
2023	1542.3
2019-2023 Average	774.3
2024	483.0
Difference (Average - 2024)	291.4
Source: EIA 861 Reliability Reports (2019-2024)	
Note: IEEE Standard	

2 The underlying basis for ABATE Witness Fitzhenry's argument is that 2024
 3 reflects all of DTE Electric's most recent investment. However, the year 2023 also
 4 includes a significant level of DTE Electric's recent reliability investment and that
 5 year is the highest in the 2019 to 2024 time horizon. 2023 was a higher frequency
 6 and intensity storm year compared to 2024⁵⁷.

7 Second, even if ABATE Witness Fitzhenry's assessment was based on
 8 SAIDI without MED, it would still be a flawed analysis. In my experience, the
 9 frequency and intensity of weather events drives a significant percentage of both
 10 MED and non-MED outages. In fact, analysis 1898 & Co. has performed for Texas
 11 utilities shows that approximately 45% to 65% of all outages can directly be linked
 12 to weather events. Given this reality, it is inappropriate to assume any single year
 13 is representative of a utility's future outages. This is a key reason why 1898 & Co.

⁵⁶ Direct Testimony of Colin T. Fitzhenry, Page 8, Table CTF-1

⁵⁷ U-21860 Direct Testimony of Brian Hill, Page 22, Lines 6-18

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1 utilizes a longer-time horizon for performing outage improvement analysis within
2 its modeling.

3 Third, the assessment and conclusions do not factor in where the outages
4 occur on the system. As noted in the 1898 & Co. report⁵⁸, Distribution Automation
5 improves mainline or backbone outages. Outages on laterals would not benefit from
6 this investment. Additionally, 1898 & Co.'s evaluation does not show it is cost-
7 beneficial to deploy distribution automation on all circuits. ABATE Witness
8 Fitzhenry's assessment of the distribution automation BCA assumes 2024 outages
9 are distributed similarly to the outage profile of 2019 to 2023. In my experience
10 evaluating historical outage records, this is a flawed assumption. This is another
11 reason why 1898 & Co. utilizes a longer-time horizon for performing outage
12 improvement analysis within its modeling.

13

14 **Q34. What is a more accurate assessment of the impact to the Distribution**
15 **Automation BCA of incorporating 2024 outage data into the evaluation?**

16 A34. Without evaluating the data and incorporating it into the modeling, I cannot
17 comment on the impact of the 2024 outage data's impact on the Distribution
18 Automation BCA. I hesitate because I do not know the distribution of the 2024 data
19 compared to the 2019-2023 data, relative to mainline vs lateral outages. Similarly,
20 I hesitate because I do not know the distribution of outage data of the 2024 data
21 compared to the 2019-2023 data relative to the beneficial circuits evaluated by 1898
22 & Co. It is entirely possible that the 2024 data would show more outages on circuits
23 that were not beneficial now, pushing them into being beneficial. Since the data
24 could actually increase the number of beneficial circuits or decrease it, I hesitate to

⁵⁸ Exh A-28 R3 Program Benefit Cost Analysis Report Sec. 3.4.2.1 Page 67

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1 speculate. What I can comment on is the impact to the average customer outage
2 impacts on the entire system of incorporating the 2024 data into the evaluation.
3 Based on the data referenced by ABATE Witness Fitzhenry, incorporating 2024
4 reliability data decreases the annual average SAID with MED by 6.27%. This is
5 much lower than the approximately 60% decrease purported by ABATE Witness
6 Fitzhenry.

7

8 **Q35. Witness AG-MN Stephens uses an observation that forecasted PTMM**
9 **modeling benefits are greater than historical actual outages to claims the**
10 **PTMM modeling overstates benefits. Can you please describe his specific**
11 **observation?**

12 A35. Yes, The 1898 & Co. Report includes two figures that show the absolute
13 improvement in CMI for circuits and then shows the percentage improvement for
14 each circuit. The figures show approximately 10% improvement in groundline pole
15 failure outages and approximately 7.5% improvement in pole-top failure outages.
16 AG-MM Witness Stephens takes the percentage improvements from both figures
17 to estimate a composite improvement of both sub-programs together. He estimates
18 the improvement to be 17.5% and then compare this to 11% of all outages are
19 equipment failures. improvement.⁵⁹

20

21 **Q36. Is Witness AG-MN Stephens observation and corresponding conclusion**
22 **accurate?**

23 A36. AG-MN Witness Stephens' assessment is based on a flawed and incorrect
24 observation of the 1898 & Co. results and comparison to historical outage records.

⁵⁹ Direct Testimony of Dennis Stephens, Page 49 line 21 – Page 50 line 5

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1 Summing up the percentage is inappropriate to estimate the composite. One
2 percentage improvement is based on groundline pole outages, the other
3 improvement is based on pole-top outages. The basis of each calculation is
4 different. Additionally, the comparison historical outage data is also not appropriate
5 as that is a percentage of total outages. The two figures show the percentage
6 improvement in groundline pole outages or pole top outages, respectively. Since
7 bases are different, summing them together and comparing them is not appropriate.
8 This makes his claim that the PTMM modeling overstates benefits invalid.

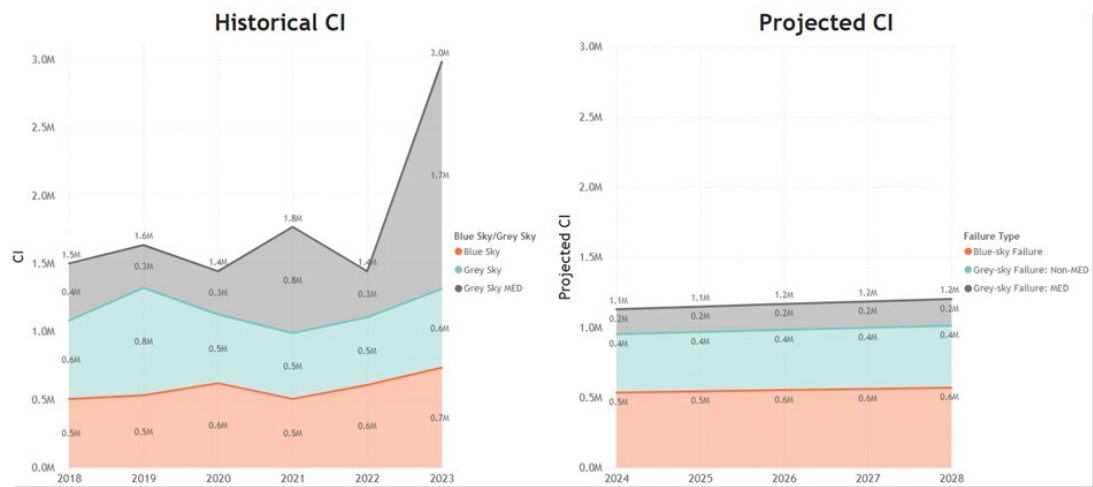
9

10 **Q37. Did 1898 & Co. provide any analysis to demonstrate the credibility of the**
11 **PTMM customer outage benefits?**

12 A37. Yes. In fact, 1898 & Co. provided analysis during discovery to validate the
13 accuracy of the modeling, specifically showing that the customer outage forecasted
14 in the model for PTMM are normalized to historical outages. Figure 2 and Figure
15 3 provides the projected CI and CMI, respectively, of pole and pole top failures
16 compared to the historical actuals. Historical actuals are based on the OMS and
17 assumed outage types that would apply. As the figures show, the project CI and
18 CMI is on average lower than the historical CI and CMI, especially for Grey-sky
19 type failures. This demonstrates that the 1898 & Co. modeling is not overestimating
20 customer benefits as has been claimed and that in fact it producing expected results.
21 The fact that 1898 & Co.'s forecasted outages aligns to historical outages
22 definitively shows that the model is valid and credible for investment decision
23 analysis to identify investments that provide the most benefits for customers.

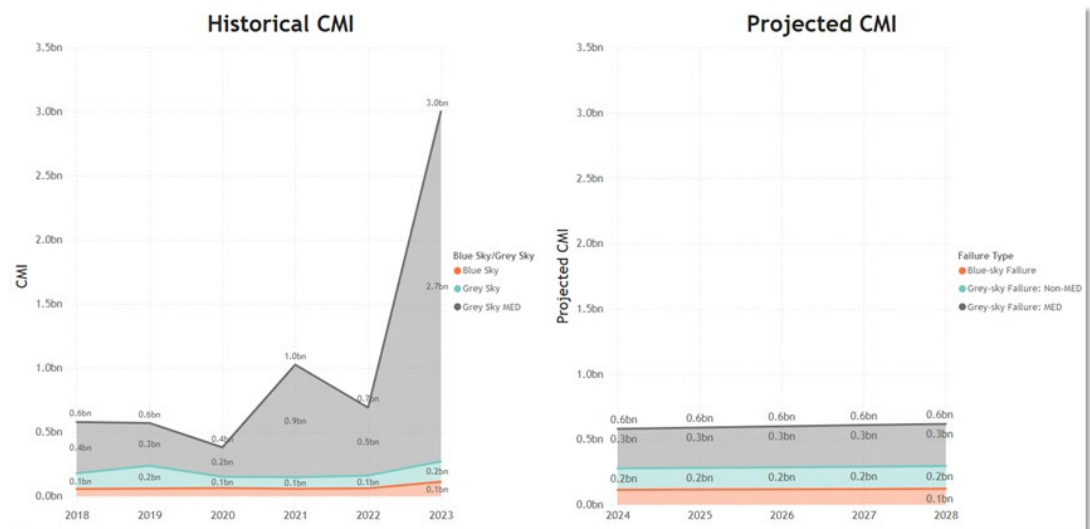
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Figure 2 Historical CI compared to Projected CI from 1898 &Co. Modeling⁶⁰



2

Figure 3 Historical CMI compared to Projected CMI from 1898 &Co. Modeling⁶¹



3 Escalation Sensitivity Analysis

4 **Q38. CEO Witness Volkman expresses concern that given recent trends in**
 5 **escalation and the uncertainty regarding future escalation that the assumed**
 6 **average escalation assumed by DTE for the PTMM program of 3.1% and**
 7 **2.5% assumed by 1898 & Co. in the BCA is low which could cause the**

⁶⁰Exhibit A48 Sch NN1 DR MNSCDE-3.58(d)

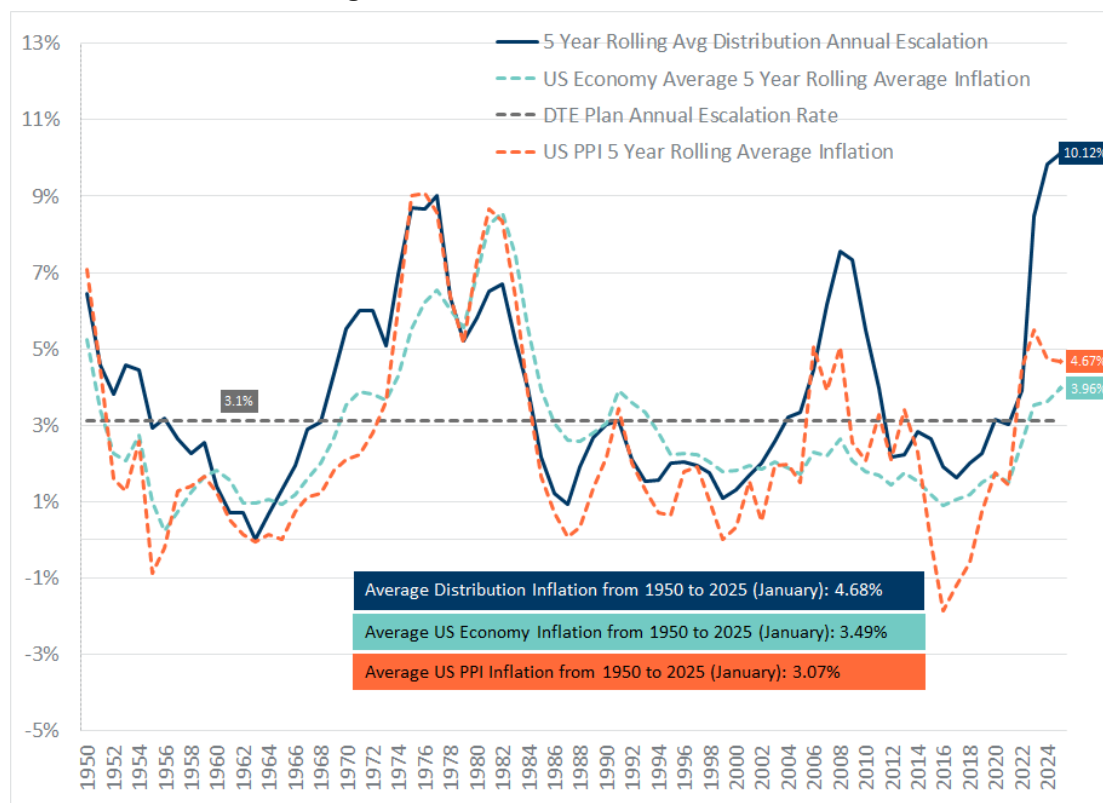
⁶¹ Ibid

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1 programs to have higher costs for customers than planned and potentially
2 impact the BCA results.⁶² What is your response to his concern?

3 A38. CEO Witness Volkman's concerns and note regarding the uncertainty of escalation
4 are valid. Figure 4 shows the historical 5 year rolling average inflation for the
5 general US economy, the producer price index (PPI), and distribution capital, all
6 compared to DTE's assumed annual escalation. As Figure 4 shows, recent trends
7 confirm CEO Witness Volkman's assessment, however, the figure also shows that
8 historical high escalation doesn't necessarily correlate to future escalation. The
9 figure also shows that distribution investment has generally been higher the general
10 economy.

11 **Figure 4 Historical Escalation Overview⁶³**



⁶² Direct Testimony of Curt Volkman, Page 16, lines 13-Page 17, line 10

⁶³ NDA Workpaper DTE JDDS-R6 Escalation History CONFIDENTIAL

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1 As it relates to 1898 & Co.'s assumed escalation of 2.5%, it is important to
2 note that the BCA assumes overnight investment. As such, escalation for the capital
3 cost is not applicable to the evaluation. The 2.5% is applicable for the benefits. If
4 escalation is higher, the model's benefits would also be higher, however this
5 increase is moderated by a higher discount rate to reflect higher inflation.

6

7 **Q39. CEO Witness Volkmann recommends that a sensitivity analysis be performed**
8 **to understand the impacts to the BCA, what sensitivity values does he**
9 **recommend?**

10 A39. For PTMM, CEO Witness Volkmann recommends sensitivities be done for cost
11 increases over the next four year of 25% or 100% for poles and 10% or 30% for
12 PTMM labor.⁶⁴ For distribution automation, he recommends recloser cost increases
13 over the next four years of 20% or 100% and 10% or 30% for distribution
14 automation labor.⁶⁵

15

16 **Q40. How would these sensitivity results impact the BCA performed by 1898 & Co.?**

17 A40. It depends on the which value is used for materials or labor and the percentage each
18 of the installed costs. For simplicity purposes, 1898 & Co. assumes materials are
19 50% of the costs and labor is the other 50%. This is a conservative weighting as
20 labor is likely higher than 50%. Based on this, 1898 & Co. estimates the following
21 annual escalation ranges for PTMM; 4.1% annually on the low side and 13.18%
22 annually on the high side. This is equivalent to increasing PTMM costs inside the
23 1898 & Co. model by 1.66% and 25.56%, respectively.⁶⁶ For distribution

⁶⁴ Direct Testimony of Curt Volkmann, Page 17 lines 17-19

⁶⁵ Direct Testimony of Curt Volkmann, Page 23 line 19 – Page 24 line 1

⁶⁶ Workpaper DTE JDDS-R7 Escalation Sensitivity Analysis

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1 automation, 1898 & Co. estimates the following annual escalation ranges; 3.55%
2 annually on the low side and 13.18% annually on the high side. This is equivalent
3 to increasing DA costs inside the 1898 & Co. model by 0.33% and 25.56%,
4 respectively.⁶⁷

5

6 **Q41. Do you have any concerns with these sensitivity values?**

7 A41. Yes, I think the high sensitivity value is too high. 13.18% annual escalation over a
8 5-year period has never been observed as shown in Figure 4. In fact, the highest 5-
9 year average value observed since 1950 is over the period of 2021 through 2025,
10 10.12% per year. Based on this, I recommend the high sensitivity value be 10.12%
11 annual, this would produce approximately a 47% increase in costs (material and
12 labor combined) in four years. This is equivalent to increasing costs inside the 1898
13 & Co. model by 17.0%.⁶⁸

14

15 **Q42. Did 1898 & Co. perform a higher escalation sensitivity analysis on the impact**
16 **to the PTMM and DA BCA?**

17 A42. Yes. 1898 & Co. assumed a 10% cost increase to the PTMM and DA programs.
18 Balancing the range of values proposed by CEO Witness Volkmann and the max
19 historical escalation, 1898 & Co. assumed a 7.45% annual escalation as an
20 appropriate sensitivity assumption. This produces a 33.3% increase in costs in four
21 years. The potential impact assessment of utilizing a revenue requirements-based
22 approach as described in the above was based on a 10% increase in the costs of
23 those programs. These results can be used for this sensitivity evaluation. It should
24 be noted that these impacts to the 1898 & Co. modeling are based on an assumption

⁶⁷ Workpaper DTE JDDS-R7 Escalation Sensitivity Analysis

⁶⁸ Ibid

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1 that longer term escalation over 40 or 50 years will be unchanged and average to
2 2.5% per year and these higher escalation values are only for short escalation. If
3 these escalation values are assumed to impact longer term escalation as well, then
4 the impact to the BCA is less than shown.

5 Table 1 and Table 2 shows the impact of this sensitivity on the PTMM
6 program. The tables show that the higher escalation sensitivity causes only 11
7 circuits, or 0.41% of all positive BCR circuits, to have their benefit cost ratio go
8 below 1 for the groundline sub-program and 16 circuits, or 0.62% of positive BCR
9 circuits, for the pole-top sub-program. As shown in the tables, these less than 1
10 BCR circuits have a weighted average BCR of 0.995 for groundline and 0.99 for
11 pole-tops, extremely close to 1.0. Additionally, the tables also show that the
12 aggregate impact to the BCR results is minor with the average groundline BCR
13 decreasing by 4.01% and the pole-top BCR decreasing by 6.98%. This shows that
14 the impact of higher escalation on 1898 & Co.'s BCA approach are minimal.

15 Table 3 shows the impact of this sensitivity on the DA program. The table
16 shows that the higher escalation sensitivity causes only 61 circuits, or 5.13% of all
17 positive BCR circuits, to have their benefit cost ratio go below 1. As shown in the
18 table, these less than 1 BCR circuits have a weighted average BCR of 0.95. When
19 considering the conservative nature of benefits assessment as outlined in my revised
20 direct testimony⁶⁹, these projects should still be considered as providing benefits in
21 excess of costs for customers. Additionally, the tables also show that the aggregate
22 impact to the BCR results is minor with the average BCR decreasing by 10%. This
23 further shows that the impact of higher escalation on 1898 & Co.'s BCA approach
24 is minimal.

⁶⁹ Case No. U-21860 Revised Direct Testimony of Jason D. De Stigter Page JDDS-31 line 14 – JDDS-32 line 2

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1 **Conclusions**

2 **Q43. Can you summarize your rebuttal testimony?**

3 A43. My rebuttal testimony has shown that each of the three core claims against the 1898
4 & Co. BCA modeling are not valid. Therefore, the main conclusions that the model
5 exaggerates the amount of investment that is likely to be cost-effective⁷⁰ and does
6 not support investment decision making⁷¹ are not supported. In addition to
7 disproving these claims regarding the 1898 & Co. modeling, my rebuttal testimony
8 also further explains why the 1898 & Co. Model is a credible tool that has generated
9 reasonable and useful results that DTE, the Commission, and stakeholders can use
10 to make decisions on investing in a more resilient and reliable grid for the benefit
11 of DTE's customers. Specifically, my testimony showed:

- 12 • 1898 & Co. and Burns & McDonnell hold high ethical standards as they
13 engage in business activities. Additionally, 1898 & Co. has provided a data-
14 centric, objective, and comprehensive evaluation. Claims of bias are
15 patently false. (refer to Alleged Bias in Model Results Section)
- 16 • The modeling costs have not been understated and employing a revenue
17 requirements-based approach is inappropriate and unnecessary. Witnesses
18 Alvarez, Stephens, and Fitzhenry did not incorporate the treatment of a
19 revenue requirements-based approach to benefits nor provide any analysis
20 on the impact of the approach to the BCA. As I've demonstrated above, the
21 BCA results would not be different between the approaches and in the
22 scenario where different opinions are accepted, the impact to the BCA
23 results is minor. I've also showed that Witness Alvarez inappropriately

⁷⁰ Direct Testimony of Paul Alvarez, Page 37, line 20 – Page 38, line 2, Direct Testimony of Melissa Stults, Page 14, lines 2-4, Direct Testimony of Dennis Stephens, Page 18, Line 9-12

⁷¹ Direct Testimony of Paul Alvarez, Page 35, lines 18-20, Direct Testimony of Colin T. Fitzhenry, Page 2, Lines 15-16

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- 1 applied a revenue requirements-based approach to only the Private LTE /
- 2 Fiber scenario leaving the Public Scenario unchanged to wrongly conclude
- 3 that Public LTE is the lower life-cycle cost alternative. (refer to Claims 1898
- 4 & Co.'s Model Understates Costs Section)
- 5 • The benefits modeling is not overstated. Witness Alvarez's views that the
- 6 ICE tool overstates benefits are unfounded and speculative. Additionally,
- 7 the valuation of critical customers does have a basis in the ICE tool and does
- 8 not impact the BCA results as significantly as suggested. Further, reliability
- 9 normalization for vegetation management and PTMM on DA BCA results
- 10 is minor, and 2024 reliability would not meaningfully change BCA results.
- 11 Finally, the overestimated customer outages observation for PTMM by
- 12 Witness Stephens are based on an incorrect assessment. (refer to Claims
- 13 1898 & Co.'s Model Overstates Benefits Section)
- 14 • The 1898 & Co. model's basis for customer outage improvements aligns to
- 15 historical outages, showing that the model is valid and credible for
- 16 investment decision analysis to identify investments that provide the most
- 17 benefits for customers. Claims that the 1898 & Co. BCA results should be
- 18 rejected as non-credible⁷² are not valid and should themselves be rejected.
- 19 • The BCA for the PTMM and DA programs are robust as shown by range
- 20 sensitivity analysis performed showing minimal impact to overall program
- 21 BCA (see Table 1, Table 2, Table 3, Table 7, Table 8, Table 9, and Table
- 22 10).

⁷² Direct Testimony of Paul Alvarez Page 6, Line 1, Direct Testimony of Colin T. Fitzhenry, Page 2, Lines 15-16

Line
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1 **Q44. What does the analysis shown in your rebuttal testimony mean for the**
2 **recommendation provided in your direct testimony?**

3 A44. All of this further validates the 1898 & Co. modeling BCA approach and results as
4 well as re-emphasizes the recommendations I made in my direct testimony.
5 Specifically this further supports that 1) the PTMM program is beneficial for DTE
6 Electric customers and delaying or stretching this program over more years will be
7 less beneficial for customers 2) the Distribution Automation program is a cost-
8 effective investment solution to improve reliability, and it provides significant
9 benefits to customers, and 3) Private LTE / Fiber is the preferred system wide or
10 global strategy for a telecommunications solution for DTE Electric customers.
11 What I will add, this evaluation shows, specifically from Table 10, that the DA
12 program should not be delayed as customers will experience higher outages.

13

14 **Q45. Does this conclude your rebuttal testimony?**

15 A45. Yes it does.

16

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

REBUTTAL TESTIMONY

OF

BRIAN L. HILL

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF BRIAN L. HILL

Line
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1 **Q1. Please state your full name, business address and by whom you are employed.**

2 A1. My name is Brian L. Hill, and my business address is One Energy Plaza, Detroit,
3 Michigan, 48226 and I am employed by DTE Electric.

4

5 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
6 **Company (DTE Electric or Company)?**

7 A2. Yes.

8

9 **Purpose of Testimony**

10 **Q3. What is the purpose of your rebuttal testimony?**

11 A3. My testimony will rebut the testimony of several witnesses, including:

- 12 • Attorney General (AG) Witness Sebastian Coppola
- 13 • Association of Businesses Advocating Tariff Equity (ABATE) Witness
- 14 Jessica A. York
- 15 • Michigan Public Service Commission (MPSC or Commission) Staff (Staff)
- 16 Witnesses Ally Durfee and Hunter Hansen
- 17 • Michigan Environmental Council (MEC), Natural Resource Defense
- 18 Council (NRDC) (collectively MNC) Witness Douglas B. Jester
- 19 • Natural Resources Defense Council (NRDC) and Citizens Utility Board of
- 20 Michigan (CUB) (collectively referred to as NRDC-CUB) Witness Richard
- 21 J. Bunch.

22 The absence of a discussion of other matters in my rebuttal testimony should not
23 be taken as an indication of agreement with other aspects of any intervenor's
24 testimony.

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1 **Q4. Are you sponsoring any exhibits?**

2 A4. Yes. I am sponsoring the following exhibits:

<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
A-52	SS-1	2024 Historic Average Recalculation – Emergent Replacements and Customer Connections, Relocations, and Other
A-52	SS-2	Corrected AG Emergent Reductions

8

9 **Q5. Were these exhibits prepared by you or under your direction?**

10 A5. Yes, they were.

11

12 **Q6. How is your rebuttal testimony organized?**

13 A6. The content and issues are listed below.

14 Rebuttal Contents

15	Purpose of Testimony	1
16	Base Capital Historical Averaging Background: Emergent Replacements and Customer	
17	Connections, Relocations & Other	3
18	Rebuttal Issue 1: Use of Constant Dollar Averaging (CDA) to forecast expenditures for	
19	the Base Capital Programs Emergent Replacements and Customer Connections,	
20	Relocations & Other	8
21	Productivity gains should equally offset labor rate increases in base capital expenditures,	
22	removing the need for CDA.....	11
23	Rebuttal Issue 2: MNC Witness Jester claims constant dollar averaging fails to account	
24	for labor productivity gains therefore is not justified.	11
25	Connection between Distribution Grid Planning, performance-based ratemaking and	
26	CDA	14
27	Rebuttal Issue 3: Connecting CDA approval to contested cases for Distribution Grid	
28	Planning and implementation of performance-based ratemaking	14
29	Use of Composite Inflation Rate for Base Capital Forecasting.....	15
30	Rebuttal Issue 4: Company's continued support for its composite inflation rate for	
31	forecasting future base capital expenditures	15
32	Base Capital – Emergent Replacements (Exhibit A-12, Schedule B5.4 Page 3)	17

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1	Rebuttal Issue 5: Company disagrees with AG Witness Coppola's argument against the	
2	use of CDA and the Company's composite inflation rate	17
3	Table 1 Summary of Corrected 2025 Emergent Reductions	20
4	Table 2 Summary of Corrected 2026 Emergent Reductions	20
5	Rebuttal Issue 6: The Company disagrees with ABATE Witness York's argument to	
6	remove 2021 for historic emergent replacement expenditures, CDA, and her support	
7	for using an alternative inflation rate	21
8	Rebuttal Issue 7: The Company disagrees with Staff Witness Durfee argument that it	
9	did not provide convincing evidence to support CDA.....	23
10	Base Capital – Customer Connections, Relocations and Other (Exhibit A-12, Schedule	
11	B5.4, page 4)	24
12	Rebuttal Issue 8: Company disagrees with AG Witness Coppola's argument for	
13	removing constant dollar averaging and using CPI-U Inflation rate for the categories in	
14	Customer Connections, Relocations, Other	24
15	Table 3 Summary of AG Witness Coppola's Recommendations for Customer	
16	Connections, Relocations, & Other	25
17	Rebuttal Issue 9: Company disagrees with ABATE York's argument to remove CDA	
18	and use on an alternative inflation rate for Customer Connections, Relocations, and	
19	Other	27
20	Rebuttal Issue 10: The Company disagrees with Staff Witness Durfee argument that it	
21	did not provide convincing evidence to support CDA.....	28
22	Rebuttal Issue 11: The Company is required to meet Michigan Department of	
23	Transportation request for relocation as they relate to I-375 (Exhibit A-12, Schedule	
24	B5.4, page 5, line 42)	29
25	Rebuttal Issue 12: The Company needs the forecasted meter expenditures to maintain	
26	meter inventory to meet customer demand (Exhibit A-12, Schedule B5.4, page 5, line	
27	68)	30
28	Table 4 2021-2023 Meters Installed Compared to Meters Purchased (Excerpt S-	
29	22.1)	31
30	Staking and Locating O&M Expenses.....	32
31	Rebuttal Issue 13: Staking and Locating O&M expense adjustment was appropriately	
32	calculated and is required to meet the projected volume and cost of staking and	
33	locating.....	32
34		
35	<u>Base Capital Historical Averaging Background: Emergent Replacements and</u>	
36	<u>Customer Connections, Relocations & Other</u>	
37	Q7. Can you briefly describe Base Capital?	

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1 A7. Yes, Base Capital includes Emergent Replacements and Customer Connections,
2 Relocations & Other.

- 3 • Emergent Replacements includes Storm, Non-Storm, and Substation
4 Reactive programs. Expenditures in these programs are necessary for
5 public safety and delivering reliable power to the Company's customers.
6 • Customer Connections, Relocations, and Other Investments are grouped in
7 key subcategories: Customer Connections and New Load, Relocations,
8 Electric System Equipment, Normal Retirement Unit Change out (NRUC)
9 and Improvement Blankets, and General Plant, Tools & Equipment and
10 Miscellaneous. Customer Connections, Relocations, and Other include
11 expenditures that connect customers to the electric grid, add capacity for
12 new customer load, relocate electric services, replace critical equipment,
13 maintain reliability, and provide necessary tools and equipment for field
14 operations.

15

16 **Q8. How does the Company forecast expenditures for the base capital programs**
17 **Emergent Replacements and Customer Connections, Relocations & Other?**

18 A8. To forecast base capital expenditures, the Company begins with historical averages,
19 which incorporates the variability and volatility in annual expenditures. It then
20 applies Constant Dollar Averaging (CDA) to the historical expenditures. It
21 subsequently adjusts for inflation in both the bridge period and projected test year.
22 Since 2018, the Company has used a five-year historic average, adjusted for CDA,
23 to forecast Emergent Replacements. Company Witness Lyons further explains the
24 prudence of constant dollar averaging.

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1 **Q9. How long has the Company used this methodology to forecast expenditures for**
2 **the base capital programs Emergent Replacements and Customer**
3 **Connections, Relocations & Other?**

4 A9. This methodology has been consistently applied in five prior electric rate cases
5 including Case Nos. U-20162, U-20531, U-20836, U-21297, and U-21534, and is
6 also being used in this instant case. Notably:

7 • In Case No. U-20836, the Commission confirmed that a five-year average
8 was appropriate, stating on page 63 of the order dated November 18, 2022,
9 “The Commission agrees with, and finds appropriate, the ALJ’s
10 recommendation for the **continued use of the five-year average** in
11 determining this category of expenditures, *along with the inflationary*
12 *adjustment to historical data*, considering this record and increased climate
13 variability over recent years.”

14 • In Case No. U-21297, the Commission again confirmed the usage of a five-
15 year average, stating on page 76 of the order dated December 1, 2023,
16 “Additionally, in light of the fact that anomalous weather is becoming the
17 norm, **the Commission agrees with the ALJ’s decision to incorporate all**
18 **five years in the average.** PFD, p. 204. As the company notes, 2023 was
19 another anomalous year.”

20 • In Case No. U-21534, the Commission again confirmed the usage of a five-
21 year average, stating on page 76 of the Order dated January 23, 2025: “The
22 Commission rejected ABATE’s proposed exclusion of 2021 in the
23 December 1 order, p. 97, and sees nothing on the instant record that
24 persuades the Commission to deviate from that decision. As the
25 Commission noted in that order, high variations in weather are becoming

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1 the norm and the Commission supports the use of the five-year
2 average.”

3

4 For Customer Connections, Relocations & Other, in 2024 (Case No. U-21534), the
5 Company began using a three-year historic average, applied CDA to the historical
6 expenditures and adjusted for inflation in both the bridge period and projected test
7 year. The Company is also using this approach in the instant case.

8

9 **Q10. What are the prevailing views on utilizing a five-year historical average to**
10 **forecast Emergent Replacements and a three-year historical average to**
11 **forecast Customer Connections, Relocations & Other Expenditures?**

12 A10. The use of a five-year historic average for Emergent Replacements and a three-year
13 historic average for Customer Connections, Relocations & Other has been accepted
14 by the Commission and discussed by witnesses in prior cases and the instant DTE
15 Electric rate case.

16 • In Case Nos. U-20162, U-20531, U-20836, U-21297 and U-21534 the
17 Commission supported using this forecasting approach for Emergent
18 Replacements.

19 • In Case No. U-21534, the Commission supported using a five-year
20 historical average for Emergent Replacements, and a three-year historical
21 average for Customer Connections, Relocations & Other¹

22 • AG Witness Coppola states in his current testimony: “To calculate an
23 appropriate forecast of capital expenditures for emergent replacement
24 programs for 2025 and 2026 forecasted periods, I used the five years

¹ Case No. U-21534, January 23 2025 Order, page 74

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1 historical average capital expenditures from 2020 to 2024...” page 25, lines

2 1-3

3 • AG Witness Coppola further states: “I will also use the most recent actual
4 historical capital expenditures for the three years 2022 to 2024 to forecast
5 future expenditures.” Page 27, lines 18-19, as it relates to Customer
6 Connections, Relocations & Other

7 • ABATE Witness York in current testimony states: “If a five-year average
8 is the Commission’s preferred approach, I recommend that DTE’s five-year
9 average reflect 2019-2020 and 2022-2024 instead of 2019-2023.” Page 24
10 lines 10-11

11 • Staff Witness Durfee in the current case forecasts 2025 and 2026 Emergent
12 capital using a five-year historic average and Customer Connections,
13 Relocations & Other using a three-year historic average (page 5)

14

15 **Q11. Should the Commission continue to support the use of historic averages to**
16 **forecast expenditures for the base capital programs Emergent Replacements**
17 **and Customer Connections, Relocations & Other?**

18 A11. Yes. The Commission should continue to support the use of a five-year historic
19 average for Emergent Replacements and a three-year historic average for Customer
20 Connections, Relocations & Other to forecast expenditures.

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1 Rebuttal Issue 1: Use of Constant Dollar Averaging (CDA) to forecast expenditures
2 for the Base Capital Programs Emergent Replacements and Customer Connections,
3 Relocations & Other

4 **Q12. What is Constant Dollar Averaging?**

5 A12. CDA is supported by Company Witness Lyons and as noted in his direct testimony
6 on page 4, constant dollar averaging of historical costs – or inflation adjusting of
7 historical costs – is a necessary step in developing cost forecasts because inflation
8 over time reduces the purchasing power of goods and services. The Constant Dollar
9 Averaging methodology adjusts historical expenditures to a common-year dollar
10 value, enhancing forecast accuracy and ensuring future expenditure estimates
11 reflect true labor and material costs.

12

13 **Q13. Can you summarize the intervenors/witnesses' positions that discussed using**
14 **CDA to forecast expenditures for the Base Capital programs Emergent**
15 **Replacements and Customer Connections, Relocations & Other?**

16 A13. Yes.

17 • Staff Witness Durfee states on page 5 of her testimony that “The Company
18 did not provide a convincing argument that it is necessary to inflate the years
19 within the five-year average for Emergent Replacements or the three-year
20 average for Customer Connections, Relocations, and Other.” She further
21 states: “There is also still not a consistent trend upward within these
22 programs.” Staff Witness Durfee did not provide any evidence to support
23 these assertions. Staff Witness Durfee proposes a reduction of
24 \$50,030,000 and \$51,580,000 for Emergent Replacements in 2025 and
25 2026, respectively. She proposes a reduction of \$23,980,000 and

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- 1 \$24,730,000 for Customer Connections, Relocations & Other in 2025 and
- 2 2026, respectively.
- 3 • AG Witness Coppola states on page 24 of his testimony: “The Company
- 4 has not provided any new compelling evidence that Constant Dollar
- 5 Averaging should be adopted”. AG Witness Coppola proposes on page 26,
- 6 lines 6-8 a reduction of \$48,795,000 and \$69,181,000 for Emergent
- 7 Replacements in 2025 and 2026, respectively. He also proposes a total
- 8 reduction of \$9,417,000 and \$19,837,000 for Customer Connections,
- 9 Relocations & Other in 2025 and 2026, respectively. Both Emergent and
- 10 Customer Connections, Relocations & Other reductions are inclusive of
- 11 other adjustments beyond CDA.
- 12 • ABATE Witness York states on page 26 of her testimony: “I believe an
- 13 uninflated five-year average is a reasonable starting point for the
- 14 development of DTE’s future test year projections.” As shown in Table
- 15 JAY-3 on page 17, she proposes a total Base Capital disallowance for 2025
- 16 and 2026 of \$315.1 million², inclusive of her proposed adjustments (using
- 17 2024 instead of 2021 in the historical average calculation for Emergent
- 18 Replacements, no CDA and using alternative inflation adjustments).
- 19 • MNC Witness Jester states on page 39 that the Company should “continue
- 20 to use historical cost averaging rather than constant dollar averaging to
- 21 project DTEE’s distribution system costs”.

² Using York’s WP, York Distribution CapExWkppr, determined the disallowances are as follows for 2025 and 2026, respectively: Emergent Replacements: \$150.2 million and \$164.9 million, Customer Connections, Relocations and Other: \$26.4 million and \$29.9 million; note these are not called out in the WP

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1 **Q14. What was the Commission’s decision on using historic inflation, or CDA,**
2 **adjustment in the most recent DTE Electric Rate Case (U-21534)?**

3 A14. In the most recent case, the Commission expressed concern with the use of constant
4 dollar averaging when it stated “The Commission found that DTE has not provided
5 a convincing argument that it is necessary to inflate the years within the five-year
6 average.”³ However, the Commission also noted that “the Commission observes
7 that its response to the use of constant dollar averaging might be different if the
8 evidence showed that these expenditure categories are both volatile and
9 consistently trending upwards.”⁴

10

11 In addition, the Commission also acknowledged on page 73 that “... no year within
12 the 2018-2022 five-year average period nor any year in the bridge or test periods is
13 actually inflated twice.” This is true again in the instant case⁵.

14

15 **Q15. Did the Company provide a convincing argument related to CDA and**
16 **demonstrate the expenditure categories are both volatile and consistently**
17 **trending upwards in this instant case?**

18 A15. Yes. Company Witness Lyons presents a compelling case in both his direct and
19 rebuttal testimony supporting the use of CDA to forecast costs. He clearly
20 demonstrates the need to adjust historical spending to reflect current economic
21 conditions and validates CDA as a reasonable and appropriate forecasting method.

³ Case No. U-21534, Order, January 23, 2025, p. 73

⁴ Case No. U-21534, Order, January 23, 2025, p. 73

⁵ AG Witness Coppola states on page 19, lines 3-12 of his DT “This compounding of historical inflation on top of costs that already reflect inflation in the year that the capital expenditures occurred is simply a methodology to increase the base costs on which the Company later adds forecasted inflation for 2024 through 2026. DTEE calls this adjustment process Constant Dollar Averaging.”

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1 Additionally, in my direct testimony (pages 9–13), I provide further evidence of
2 consistent upward trends in material and labor costs, reinforcing the volatility and
3 increases of these expenditures. I also provide additional details below in Rebuttal
4 Issue 2.

5

6 **Q16. Should the Commission support the use of CDA for the Base Capital programs**
7 **Emergent Replacements and Customer Connections, Relocations & Other?**

8 A16. Yes. As directed by the Commission, both Company Witness Lyons and I have
9 provided substantial evidence of volatility and upward trends in costs to support the
10 use of CDA in the instant case. These facts directly support the use of CDA, and
11 the opposing assertions should be rejected. The Commission should adopt CDA as
12 a sound and necessary approach for forecasting base capital expenditures.

13

14 **Productivity gains should equally offset labor rate increases in base capital**
15 **expenditures, removing the need for CDA**

16 Rebuttal Issue 2: MNC Witness Jester claims constant dollar averaging fails to
17 account for labor productivity gains therefore is not justified.

18 **Q17. What does MNC Witness Jester claim regarding Distribution Operations**
19 **labor rates and productivity changes?**

20 A17. MNC Witness Jester does not believe that there has been an upward trend in
21 Distribution Operations labor rates that justifies constant dollar averaging and that
22 changes in labor productivity were not accounted for (page 17, line 3-7).

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1 **Q18. How does the Company respond to this claim?**

2 A18. The Company disagrees. As outlined in my direct testimony starting on page 11
3 (question 20 and 21) contract labor costs have increased significantly since 2019;
4 18% for underground, 31% for overhead and 34% for tree trimming. Additionally
5 Witness Jester overlooks material cost, a key component of constant dollar
6 averaging. As shown on page 12 of my direct testimony, material costs have risen
7 by 21% to 468% from 2020-2024 across major categories. Material purchases
8 represent approximately 15% of base capital expenditures. His argument against
9 using constant dollar averaging fails to account for these substantial cost increases.
10 Based on these facts, I conclude that the Company has provided evidence that there
11 has been an upward trend in Distribution Operations rates. The Commission should
12 reject MNC Witness Jester's recommendation that CDA not be allowed for
13 Distribution Operations capital spending in this case and adopt the use of CDA for
14 forecasting base capital programs Emergent Replacements and Customer
15 Connections, Relocations & Other.

16

17 **Q19. Does MNC Witness Jester make any other claims?**

18 A19. Yes. He also states on page 17, lines 7-12 that "The Commission should expect
19 continuous improvement in labor productivity, as occurs in the rest of the economy.
20 Further, as shown in the testimony of my colleague Richard Bunch, DTEE has in
21 fact achieved reduced staffing that largely offsets internal labor compensation rates
22 per employee. The Commission and DTEE should expect similar performance from
23 DTEE's contract labor. Constant dollar averaging fails to account for productivity
24 improvements."

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1 **Q20. Does the Company agree that DTE Electric has achieved reduced staffing that**
2 **largely offsets internal labor compensation rates per employee?**

3 A20. No. Company Witness Fix rebuts the incorrect assertions made by Witness Bunch
4 related to internal labor cost escalation and his calculation of the Company's
5 compound average growth in total compensation costs for the period 2019 through
6 2024 of 0.23%.

7
8 **Q21. Does Witness Jester provide quantifiable evidence supporting productivity**
9 **gains equally offset labor rate increases?**

10 A21. No. The Company's Base Capital work is primarily performed by the Company's
11 represented field employees and contractors. Witness Jester relies solely on
12 NRDC-CUB Witness Bunch's flawed analysis, which considers only internal labor
13 costs, to argue that constant dollar averaging overlooks productivity gains. He
14 provides no quantifiable evidence to show that these gains could offset contract
15 labor cost increases of up to 34% nor does he offer any analysis linking general
16 economic trends to the Company's operations. In addition, as shown in Column H
17 lines 8 and 27 of Company Witness Fix's Exhibit A-55, Schedule VV2, the
18 compounded annual growth rate for 2019-2024 for the Company's represented
19 workforce is much higher than the 0.23% at 4.49% and 3.79% for total
20 compensation and cash compensation, respectively.

21

22 **Q22. Should the Commission consider labor productivity as an offset to the need for**
23 **CDA?**

24 A22. No. The Commission should reject MNC Witness Jester's recommendation that
25 CDA not be allowed for Distribution Operations capital spending in this case and

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1 adopt the use of CDA for forecasting base capital programs Emergent
2 Replacements and Customer Connections, Relocations & Other. Although the
3 Company applies continuous improvement methods, Witness Jester provided no
4 evidence that labor productivity gains would offset the substantial increases in labor
5 and material costs. Company Witness Bruzzano further explains the gaps in
6 Witness Bunch's labor productivity assertions in his rebuttal testimony.

7

8 **Connection between Distribution Grid Planning, performance-based ratemaking**
9 **and CDA**

10 Rebuttal Issue 3: Connecting CDA approval to contested cases for Distribution Grid
11 Planning and implementation of performance-based ratemaking

12 **Q23. In addition to the concerns above, what other concerns does MNC Jester**
13 **recommend have regarding constant dollar averaging?**

14 A23. In his direct testimony, MNC Witness Jesters states on page 23 "Given DTE's poor
15 reliability and steadily increasing Distribution Operations capital spending, I
16 recommend that the Commission establish a contested case process for Distributed
17 Grid Planning and implement a performance-based ratemaking approach for DTE's
18 Distribution Capital, including its Base Capital programs, with spending subject to
19 approval in the contested Distribution Grid Plans. This would align cost recovery
20 with proven improvements in distribution infrastructure, enhance transparency, and
21 create incentives for efficient capital deployment. In the alternative, I recommend
22 that constant dollar averaging not be allowed for Distribution Operations capital
23 spending in this case."

24

25 **Q24. Does the Company agree with this recommendation?**

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1 A24. No. Company Witness Chiu’s rebuttal addresses the recommendation to establish
2 a contested case process for the Distribution Grid Plan (DGP) and implement
3 performance-based ratemaking (PBR) for Distribution capital including Base
4 Capital programs. Witness Lyons also addresses the examples provided by MNC
5 Witness Jester related to CDA and PBR in his rebuttal testimony. Witness Jester’s
6 attempt to link the CDA to the DGP and PBR lacks a clear basis and is unsupported
7 by evidence. Moreover, Witness Jester’s proposal to tie CDA to unrelated matters
8 (PBR and the nature of the DGP) undermines the very premise of objecting to CDA
9 – either CDA is appropriate, or it is not. Its validity is not contingent. The
10 recommendation to disallow CDA as an alternative to a contested case DGP and
11 implementing PBR is unjustified, and the Commission should reject it.

12

13 **Use of Composite Inflation Rate for Base Capital Forecasting**

14 Rebuttal Issue 4: Company’s continued support for its composite inflation rate for
15 forecasting future base capital expenditures

16 **Q25. What inflation rate does AG Witness Coppola suggest using for forecasting**
17 **future base capital expenditures?**

18 A25. On page 17, line 9-11 of his direct testimony Witness Coppola states: “The inflation
19 factors are 2.8% for 2025 and 2.4% for 2026. These rates reflect the Consumer
20 Price Index-Urban forecast presented in the June 2025 US Economic Outlook
21 report prepared by S&P Global Markey Intelligence.”

22

23 **Q26. What inflation rate is ABATE Witness York’s recommendation regarding**
24 **calculation of future levels of base capital expenditures?**

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1 A26. ABATE Witness York on page 27 argues that the Company should use GDP
2 Chained Real Price Index rather than CPI inflation rates to project future for all
3 base capital categories. On page 8, lines 18-20 she argues: "DTE's CPI-U inflation
4 rates are now outdated. In addition, DTE's wage escalation assumption does not
5 consider that certain escalations may be managed such that the expense may not
6 increase at the overall cost of inflation."

7

8 **Q27. What inflation rate is NRDC-CUB Witness Bunch recommending for**
9 **forecasting future expenditures?**

10 A27. On page 22, line 18, NRDC-CUB Witness Bunch states: "Using these
11 recommendations for the labor factor and the proposed CPI-U rates for the non-
12 labor factor in Q2, I arrive at inflation escalators of 0.6%, 1.3%, and 1.2% for 2024,
13 2025, and 2026, respectively."

14

15 **Q28. Does the Company agree with the use of these inflation rates?**

16 A28. No. As presented by Company Witness Uzenski in her revised direct testimony on
17 pages 35-36 and further supported by Company Witness Bruzzano in his rebuttal
18 testimony, the Company's estimated level of inflation for 2025 is 3.00% and 2026
19 is 3.10%. The Commission should reject other proposed rates and any associated
20 adjustments to capital expenditures.

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1 **Base Capital – Emergent Replacements (Exhibit A-12, Schedule B5.4 Page 3)**

2 Rebuttal Issue 5: Company disagrees with AG Witness Coppola’s argument against
3 the use of CDA and the Company’s composite inflation rate

4 **Q29. What is AG Witness Coppola’s recommended reduction in Emergent**
5 **Replacements in 2025 and 2026?**

6 A29. Witness Coppola, on page 26, lines 6-8 of his direct testimony, “..., I recommend
7 that the Commission remove the difference of \$48,795,000 for 2025 and
8 \$69,181,000 for 2026 from the Company’s forecasted capital expenditures.”

9
10 **Q30. Why does AG Witness Coppola propose this reduction?**

11 A30. The proposed reduction is based on AG Witness Coppola’s recommendation to
12 reject CDA, reject the composite inflation rate, and use 2020-2024 for the historic
13 average.

14
15 **Q31. Should the Commission adopt AG Witness Coppola’s proposed reduction for**
16 **Emergent Replacements?**

17 A31. No. The Company, as discussed above, has supported its five-year historical
18 average, the use of constant dollar averaging and the Company’s inflation rate. The
19 use of CDA is further supported by Company Witness Lyon’s direct and rebuttal
20 testimony. Based on this evidence, the Commission should reject the proposed
21 reduction of \$48,795,000 and \$69,181,000 for years 2025 and 2026, respectively.

22
23 **Q32. Using Witness Coppola’s approach, do you agree with his calculation of the**
24 **Emergent Replacement proposed reduction?**

Line
No.

1 A32. No, in the event the Commission agrees with the approach taken by Witness
2 Coppola, his calculation overstates the 2026 reduction for non-storm and
3 incorrectly calculates the Substation Reactive reduction.
4

5 **Q33. How does Witness Coppola overstate the 2026 reduction for non-storm?**

6 A33. In his approach, Witness Coppola calculates the reduction as the difference between
7 the original forecasted amount and his projected amount. In the case of non-storm,
8 the Company's projected amount was \$254,241,000, which is the sum of the
9 "Projected Non-Storm Replacements" Exhibit A-12, Schedule B5.4 page 3, line 16,
10 column (h) and "Projected 2026 Corrective Maintenance" Exhibit A-12, Schedule
11 B5.4 page 3, line 17, column (h). The initial projections are also shown in yellow
12 in Exhibit A-52, Schedule SS-2 on page 1. Witness Coppola only included the
13 "Projected Non-Storm Replacements" as shown in yellow on page 2 of Exhibit A-
14 52, Schedule SS-2 and missed including the "Projected 2026 Corrective
15 Maintenance" in his calculations. This omission overstates the reduction by
16 \$13,654,000 as shown in red on page 2 of Exhibit A-52, Schedule SS-2.
17

18 **Q34. How does Witness Coppola incorrectly calculate the Substation Reactive**
19 **reduction for 2025 and 2026?**

20 A34. Witness Coppola uses the same approach for Substation Reactive as non-storm. By
21 using this approach, he missed two additional projections - "Projected 2025
22 Substation Facility Repair" Exhibit A-12, Schedule B5.4 page 3, line 25, column
23 (h) and "Projected 2026 Corrective Maintenance" Exhibit A-12, Schedule B5.4
24 page 3, line 26, column (h). The Company's initial projection is shown in blue on
25 page 1 of Exhibit A-52, Schedule SS-2. These omissions overstate the reduction by

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1 \$8,000,000 in 2025 and \$9,847,000 in 2026 as shown in orange on page 2 of Exhibit
2 A-52, Schedule SS-2.

3

4 Additionally, Witness Coppola calculates a five-year average for Substation
5 Reactive of \$50,946,000⁶. Using the actuals provided in Exhibit A-12, Schedule
6 B5.4, the five-year average from 2020-2024 is \$42,703,000⁷ as shown in green on
7 page 2 of Exhibit A-52, Schedule SS-2. Using the correct five-year average and
8 including “Projected 2025 Substation Facility Repair” and “Projected 2026
9 Corrective Maintenance”, the projected 2025 Substation Reactive is \$51,899,000⁸
10 and the projected 2026 Substation Reactive is \$54,799,000⁹. This results in a 2025
11 reduction of \$4,653,000 and 2026 reduction of \$5,104,000.

12

13 **Q35. Based upon the corrections made to Witness Coppola’s calculated reduction**
14 **in Non-storm and Substation Reactive, what would the reduction proposed by**
15 **Witness Coppola be?**

16 A35. The Company forecasted \$544.0 million 2025 and \$575.9 million for 2026 for
17 Emergent Replacements as shown on Exhibit A-12 Schedule B5.4 line 7. Using
18 Witness Coppola’s inflation rate and removing the historical inflation adjustments,
19 Witness Coppola’s forecasted costs should be \$494.7 million for 2025 and \$521.5
20 million for 2026. This would be a proposed reduction of \$49.3 million in 2025 and
21 \$54.4 million. This is a \$473,000 increased reduction in 2025 and \$14.8 million
22 decreased reduction for 2026. See Tables 1 and 2 below for details. In the event

⁶ Coppola DT, pg. 26, line 1

⁷ $(38,131+46,008+40,382+41,178+47,816) / 5 = 42,703$

⁸ Exhibit A-52, Schedule SS-1 sum of lines 20, 22 and 25 in column h $(42,703,000+1,196,000+8,000,000)$

⁹ Exhibit A-52, Schedule SS-1 sum of lines 24 and 26 $(44,952,000+9,847,000)$

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the Commission adopts Witness Coppola's recommended reductions, the amounts should be updated to reflect these changes.

Table 1 Summary of Corrected 2025 Emergent Reductions

Emergent Replacements	Initial Filing (\$000)	Corrected Forecast (\$000)	Corrected Reduction
Storm	276,370	237,025	(39,345)
Non-Storm	233,353	228,083	(5,270)
Substation Reactive	56,552	51,899	(4,653)
Emergent Replacement Reduction Based on Strategic Spend	(22,295)	(22,295)	0
Total Emergent Replacements	543,980	494,712	(48,267)

Table 2 Summary of Corrected 2026 Emergent Reductions

Emergent Replacements	Initial Filing (\$000)	Corrected Forecast (\$000)	Corrected Reductions
Storm	284,937	242,714	(42,223)
Non-Storm	254,241	247,211	(7,030)
Substation Reactive	59,903	54,799	(5,104)
Emergent Replacement Reduction Based on Strategic Spend	(23,229)	(23,229)	0
Total Emergent Replacements	575,852	521,495	(54,358)

Q36. Did the Company recalculate the capital request related to Emergent Replacements with 2020-2024 as the five-year historic average along with the Company's proposed CDA methodology?

A36. Yes. In the event the Commission adopts Witness Coppola's proposal to update the Company's five-year average (2019-2023), the Company recalculated its proposed request for Emergent Replacements using a five-year average of 2020-2024,

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1 applied CDA and inflation. The result to the Company's original proposal is an
2 increase investment of \$19.2 million and \$19.8 million for 2025 and 2026,
3 respectively as shown in Exhibit A-52, Schedule SS-1.

4

5 Rebuttal Issue 6: The Company disagrees with ABATE Witness York's argument to
6 remove 2021 for historic emergent replacement expenditures, CDA, and her support
7 for using an alternative inflation rate

8 **Q37. What does ABATE Witness York argue concerning historic averages used to**
9 **forecast Emergent Replacements?**

10 A37. ABATE Witness York on page 24 line 11, recommends the adoption of a non-
11 consecutive five-year historic average 2019-2020 and 2022-2024.

12

13 **Q38. Why does ABATE Witness York make these recommendations?**

14 A38. On page 23, lines 12-16, ABATE Witness York states: "While the five-year
15 average has historically been approved by the Commission, I continue to believe it
16 is inappropriate to include 2021 in the five-year average in this case. Calendar year
17 2021 was an abnormal year in terms of storm activity, resulting in nearly \$400
18 million of storm-related emergent replacements, which DTE acknowledged in a
19 prior rate case was unprecedented."

20

21 **Q39. Does the Company agree with ABATE Witness York's recommended method**
22 **to calculate the level of Emergent Replacements using a five-year non-**
23 **consecutive historical average, and her resultant proposed reduction?**

24 A39. No. The Company disagrees with using a non-consecutive five-year average. The
25 use of a five-year historic average is intended to and does appropriately account for

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1 weather volatility when forecasting future capital expenditures for Emergent
2 Replacements. Selectively excluding the highest storm years and excluding them
3 undermines the intent of a five-year average to account for year-to-year variability
4 in weather.

5

6 The Company acknowledged in Case No. U-21297 that the storms in the Summer
7 of 2021 were historic, but that did not imply that severe weather events will never
8 occur again. In fact, as explained in my direct testimony in Case No. U-21534, T6
9 3036-3041, in 2023 the Company experienced the worst ice storm in its history
10 along with six summer tornadoes resulting in major damage to the electric grid. In
11 total, the Company experienced seven storms in 2023, with five storms meeting the
12 catastrophic threshold.

13

14 **Q40. Has the Commission ruled whether a five-year average is appropriate?**

15 A40. Yes, as noted above in the background section of my testimony, using a five-year
16 average when forecasting has been approved in prior Case Nos. U-20162, U-20561,
17 U-20836, U-21297 and most recently in U-21534.

18

19 **Q41. What is ABATE Witness York's proposed reduction associated with**
20 **Emergent Replacements?**

21 A41. ABATE Witness York recommends, on page 27, lines 11-18: "For the reasons
22 described above, I recommend that: 1) the historical five-year average emergent
23 replacement capital expenditure level include 2024 instead of 2021; 2) no inflation
24 adjustments be applied to the actual historical capital expenditures used to the
25 develop the five-year average of Emergent Replacement investment and the three-

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1 year average actual historical capital expenditures for Customer Connections and
2 Relocations; and 3) that the same future inflation adjustments I recommended for
3 O&M expenses be applied in the development of projected bridge period and test
4 year capital expenditures.” Witness York does not provide the reduction amounts
5 associated in her direct testimony.” Using York’s WP, York Distribution
6 CapExWkppr, the Company was able to determine her proposed reduction for
7 Emergent Replacements as \$150.2 million for 2025 and \$164.9 million for 2026.

8

9 **Q42. Should the Commission adopt ABATE Witness York’s proposed reduction**
10 **associated with Emergent Replacements?**

11 A42. No. The Commission should reject ABATE Witness York’s recommended
12 reduction of Emergent Replacements expenditures (based on a five-year average
13 excluding 2021). The use of a five-year historic average is the most reasonable and
14 prudent way to forecast future Emergent Replacement expenditures and has been
15 consistently approved by the Commission as noted above. The Commission should
16 also reject any reduction associated with removing the constant dollar averaging
17 (Rebuttal Issue 1) and the use of a composite inflation rate (Rebuttal Issue 4).

18

19 Rebuttal Issue 7: The Company disagrees with Staff Witness Durfee argument that it
20 did not provide convincing evidence to support CDA

21 **Q43. What does Staff Witness Durfee say about CDA in her testimony?**

22 A43. On page 5, lines 7-10 of her direct testimony Witness Durfee states: “The Company
23 did not provide a convincing argument that it is necessary to inflate the years
24 withing the five-year average for Emergent Replacements or the three-year average

Line
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1 for Customer Connections, Relocations, and Other. There is also still not a
2 consistent trend upward within these programs.”
3

4 **Q44. Do you agree with Staff Witness Durfee’s statement?**

5 A44. No. Witness Durfee makes her statement without directly addressing the evidence
6 the Company has presented in this case. Company Witness Lyons provides ample
7 evidence in his direct and rebuttal testimony for the use of CDA. In my testimony
8 I provide direct evidence of base capital increasing upward trends in both labor and
9 material costs over the historic period. Witness Durfee does not address either of
10 these testimonies.
11

12 **Q45. Should the Commission accept Staff Witness Durfee’s statement that the**
13 **Company did not provide convincing evidence in the instant case?**

14 A45. No. The Company has provided substantial evidence of volatility and upward cost
15 trends in the instant case as noted throughout my rebuttal testimony and the
16 testimony of Company Witness Lyons.
17

18 **Base Capital – Customer Connections, Relocations and Other (Exhibit A-12,**

19 **Schedule B5.4, page 4)**

20 Rebuttal Issue 8: Company disagrees with AG Witness Coppola’s argument for
21 removing constant dollar averaging and using CPI-U Inflation rate for the categories
22 in Customer Connections, Relocations, Other

23 **Q46. What are AG Witness Coppola’s recommendations in the Category of**
24 **Customer Connections, Relocations, & Other?**

Line
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1 A46. AG Witness Coppola correctly consolidates his recommendations to the higher-
2 level subcategories within Customer Connections, Relocations, & Other. His
3 recommendations are summarized in Table 1 and does not include the I-375 project
4 disallowance. It should be noted AG Witness Coppola includes the I-375 project in
5 his Relocation recommendation. I will address this project later in my rebuttal
6 testimony.

7

8 **Table 3 Summary of AG Witness Coppola's Recommendations for**
9 **Customer Connections, Relocations, & Other**

Subcategory	Exhibit A-12 Sch. 5.4	2025 Increase/(Decrease)	2026 Increase/(Decrease)	Coppola Direct Page
Connections and New Load	Page 4, Line 35	\$1,745,000	(\$8,806,000)	29
Relocations	Page 5, Line 58	(\$12,250,000)	(\$11,785,000)	34
Electric System Equipment	Page 5, Line 69	\$2,981,000	\$2,935,000	36
NRUC and Impr. Blankets	Page 6, Line 83	(\$1,276,000)	(\$1,499,000)	37
General Plant, Tools, & Equip	Page 6, Line 91	(\$617,000)	(\$682,000)	38

10

11 **Q47. Why does AG Witness Coppola make these recommendations?**

12 A47. AG Witness Coppola makes this recommendation based on three factors. First, he
13 proposes rejecting the use of CDA; second, he proposes the use of CPI-U inflation
14 rates for calculating forecasted expenditures in 2025 and 2026; and third, he
15 proposes using 2022-2024 as the three-year average instead of 2021-2023.

16

17 **Q48. Do you agree with AG Witness Coppola's recommendations for Customer**
18 **Connections, Relocations, & Other?**

Line
No.

1 A48. No. The Company has also fully supported the use of historical cost averaging,
2 CDA, and the composite inflation rate for use in forecasting future base capital
3 expenditures through Witness Lyon's direct and rebuttal testimony and discussed
4 above for Emergent Replacements in Rebuttal Issues 1, 4 and 5.
5

6 **Q49. Did the Company recalculate the capital request related to Emergent**
7 **Replacements with 2022-2024 as the three-year historic average as proposed**
8 **by Witness Coppola along with the Company's proposed methodology?**

9 A49. Yes. In the event the Commission adopts Witness Coppola's proposal using an
10 updated three-year average, the Company recalculated its proposed request for
11 Customer Connections, Relocations, and Other using a three-year average of 2022-
12 2024, applied CDA and inflation. This would result in a total increase to Customer
13 Connections, Relocations & Other from the Company's original proposal of \$40.2
14 million and \$44.3 million for 2025 and 2026, respectively as shown in Exhibit A-
15 52 Schedule SS-1.
16

17 **Q50. Should the Commission adopt AG Witness Coppola's proposed reduction?**

18 A50. No. The Company has addressed all three of AG Witness Coppola's arguments for
19 disallowing capital in Customer Connections, Relocations & Other. Company
20 Witness Lyons has shown the need for CDA in his direct and rebuttal testimony as
21 I have, as discussed above. Additionally, Company Witnesses Uzenski, and
22 Bruzzano have supported the use of the composite inflation rate. In addition, the
23 Company has recalculated its proposal using an updated three-year average as
24 detailed in Q49.

Line
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1 Rebuttal Issue 9: Company disagrees with ABATE York's argument to remove CDA
2 and use on an alternative inflation rate for Customer Connections, Relocations, and
3 Other

4 **Q51. What does ABATE Witness York argue concerning historic averages used to**
5 **forecast Customer Connections, Relocations and Other?**

6 **A51.** On page 27, lines 5–8 of his testimony, ABATE Witness York makes similar
7 recommendations regarding inflation adjustments for Emergent Replacements.
8 These include removing the use of CDA and applying an alternative inflation rate
9 in the development of projected capital expenditures for Customer Connections,
10 Relocations and Other.

11

12 **Q52. What is ABATE Witness York's proposed reduction associated with**
13 **Customer Connections, Relocations, and Other?**

14 **A52.** Witness York does not provide the reduction amounts associated specifically with
15 Customer Connections, Relocations and Other in her direct testimony. Using
16 York's WP, York Distribution CapExWkppr, the Company was able to determine
17 her proposed reduction for 2025 and 2026 as \$26.4 million and \$29.9 million,
18 respectively.

19

20 **Q53. Should the Commission adopt ABATE Witness York's proposed reduction**
21 **associated with Customer Connections, Relocations, and Other?**

22 **A53.** No. The Commission should reject any reduction associated with removing the
23 constant dollar averaging. It should also reject the use of a composite inflation rate
24 (addressed in Rebuttal issue 4) and the associated recommended reduction of
25 capital expenditures in the base capital programs associated with Customer

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1 Connections, Relocations and Other. As previously stated, CDA is supported by
2 Company Witness Lyons and as noted in his direct testimony on page 4, constant
3 dollar averaging of historical costs – or inflation adjusting of historical costs – is a
4 necessary step in developing cost forecasts because inflation over time reduces the
5 purchasing power of goods and services.

6

7 Rebuttal Issue 10: The Company disagrees with Staff Witness Durfee argument that
8 it did not provide convincing evidence to support CDA

9 **Q54. What does Staff Witness Durfee say about CDA in her testimony?**

10 A54. On page 5, lines 7-10 of her direct testimony Witness Durfee states: “The Company
11 did not provide a convincing argument that it is necessary to inflate the years
12 withing the five-year average for Emergent Replacements or the three-year average
13 for Customer Connections, Relocations, and Other. There is also still not a
14 consistent trend upward within these programs.”

15

16 **Q55. Do you agree with Staff Witness Durfee’s statement?**

17 A55. No. Witness Durfee makes her statement without directly addressing the evidence
18 the Company has entered into the record. Company Witness Lyons provides ample
19 evidence in his testimony for the use of CDA. In my testimony I provide direct
20 evidence of upward trends in labor and material costs over the historic period.
21 Witness Durfee does not address either of these testimonies.

22

23 **Q56. Should the Commission accept Staff Witness Durfee’s statement that the**
24 **Company did not provide convincing evidence in the instant case?**

Line
No.

1 A56. No. The Company has provided substantial evidence in the instant case as noted
2 throughout my rebuttal testimony and the testimony of Company Witness Lyons.

3

4 Rebuttal Issue 11: The Company is required to meet Michigan Department of
5 Transportation request for relocation as they relate to I-375 (Exhibit A-12, Schedule
6 B5.4, page 5, line 42)

7 **Q57. What is AG Witness Coppola's recommendation regarding the I-375**
8 **Relocation Project?**

9 A57. He recommends reduction of \$15 million for 2025 and 2026 associated with the
10 MDOT required I-375 Relocation Project (page 34, lines 8-10). These
11 recommended reduction amounts reflect the entirety of the Company's requested
12 capital expenditures for the project.

13

14 **Q58. Why does AG Witness Coppola's recommend fully removing the 2025 and**
15 **2026 expenditures for the I-375 Relocation Project?**

16 A58. AG Witness Coppola states on page 34, lines 4-6, "In a recent development, on
17 August 11, 2025, the Detroit News reported that the Whitmer administration was
18 re-evaluating the entire I-375 project in light of significant cost overruns and recent
19 community pushback about the project."

20

21 **Q59. Do you agree with AG Witness Coppola's recommendation for a full reduction**
22 **for 2025 and 2026 expenditures for the I-375 Relocation Project?**

23 A59. No. The Company received a notice to vacate from MDOT and is required to
24 proceed with work related to this project. It is not reasonable to expect that the
25 entirety of the project will be delayed and that no work will be performed by the

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1 Company in 2025 or 2026. As of this rebuttal testimony, the Company forecasts
2 investing \$8.4 million in 2025 and \$12.0 million in 2026 - reductions of \$6.6
3 million and \$3.0 million, respectively, from the amounts included in Exhibit A-12,
4 Schedule B5.4. The Company will continue to monitor the project and appropriate
5 schedule.

6

7 **Q60. Should the Commission adopt AG Witness Coppola's proposed reduction?**

8 A60. No. The Company has adjusted its forecast based on the best available information
9 at this time and is willing to accept a reduction of \$6.6 million and \$3.0 million in
10 2025 and 2026, respectively.

11

12 Rebuttal Issue 12: The Company needs the forecasted meter expenditures to maintain
13 meter inventory to meet customer demand (Exhibit A-12, Schedule B5.4, page 5, line
14 68)

15 **Q61. What is Staff Witness Hansen's recommendation regarding Meters?**

16 A61. Staff Witness Hansen is recommending a reduction of \$12,843,918 for Meters
17 (page 6, line 5), which is broken down to \$6,301,228 and \$6,542,690 for 2025 and
18 2026, respectively.

19

20 **Q62. What is the basis for Staff Witness Hansen's proposed reduction?**

21 A62. Staff Witness Hansen notes that in 2024 the Company purchased approximately
22 70,000 more meters than it has historically purchased annually in the years 2021 –
23 2023. Based on this observation he states: "Staff believes that because the Company
24 purchased nearly 70,000 extra meters in 2024, which would be expected to be
25 delivered to the Company in 2025 and 2026 given the extended lead times, the

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1 Company does not need to purchase the same number of meters that it had been
2 purchasing in the years prior to 2024.” (page 4 line 23 to page 5 lines 4.)
3

4 **Q63. Do you agree with Staff Witness Hansen’s recommendation?**

5 A63. No. As noted by Staff Witness Hansen in his testimony, page 4 lines 18-23: “The
6 Company stated that this increase in meter purchases was because there were higher
7 than normal meter failures in 2023 and supply chain lead times increased from 4-5
8 months to 12-15 months, the Company additionally explained, ‘Based on these
9 factors, the Company ordered additional meters in 2024 to ensure sufficient
10 inventory for our customers.’” In addition, Staff Exhibit S-22.1 Projected Meters
11 Adjustment Calculation shows that in the years 2021 through 2023 the Company
12 installed 36,085 more meters than it purchased:
13

14 **Table 4 2021-2023 Meters Installed Compared to Meters Purchased**

15 **(Excerpt S-22.1)**

Year	Line No.	Meters Installed	Line No.	Meters Purchased	Delta
2021	1	59,214	6	38,240	(20,975)
2022	2	54,296	7	59,320	2,024
2023	3	59,920	8	42,785	(17,135)
	Total	173,430		137,345	(36,085)

16
17 The purchase volume of meters in 2024 (70,000) was necessary to maintain
18 adequate inventory to meet customer needs and balance its meter inventory.

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No.

1 **Q64. Should the Commission adopt Staff Witness Hansen’s recommendation to**
2 **disallow all amounts associated with meter purchases in 2025 and 2026?**

3 A64. No. The purchases made in 2024 were simply a one-time additional purchase to
4 maintain inventory of meters and should not be the determinant for future meter
5 needs. The Commission should reject the reduction of \$12,843,918.

6

7 **Staking and Locating O&M Expenses**

8 Rebuttal Issue 13: Staking and Locating O&M expense adjustment was appropriately
9 calculated and is required to meet the projected volume and cost of staking and
10 locating

11 **Q65. What is AG Witness Coppola’s recommendation for Staking and Locating**
12 **O&M Expense?**

13 A65. Witness Coppola recommends that “the Commission remove the special increase
14 in expense of \$1,618,000 proposed by the Company.” (page 116, lines 7-8)

15

16 **Q66. What was the basis of AG Witness Coppola’s recommendation?**

17 A66. AG Witness Coppola states: " First, inflationary cost increases should not be added
18 to contractor cost increases because the inflation increases reflect increases in
19 prices. This is clearly a duplication worth about \$675,000. Second, the Company
20 forecasted volume increases for an additional 38,468 staking and locating requests
21 between 2023 and 2026. This increase is inordinate and appears to be driven by the
22 surge in staking and locating requests in 2021 and 2022 following the downturn in
23 construction in 2020 from Covid-19. Third, the contractor cost to complete each
24 staking and locating request increases by 41% from 2023 to 2026. This rate of
25 increase is exorbitant and unsupported.” (page 115, lines 3-11)

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No.

1 **Q67. Is there a duplication of expenses as claimed by AG Witness Coppola?**

2 A67. AG Witness Coppola's claim of a \$675,000 duplication due to inflation adjustments
3 is unsupported in his testimony or exhibits, and the Company is unaware of how
4 this figure was calculated. As such, the proposed reduction should be rejected.
5

6 **Q68. Is the forecasted increase in staking and location requests inordinate and**
7 **based on 2021 and 2022 post COVID surge as claimed by AG Witness**
8 **Coppola?**

9 A68. No. AG Witness Coppola argues that the forecasted volume increases by 38,468
10 staking and locating requests from 2023 to 2026, "is inordinate and appears to be
11 driven by the surge in staking and locating requests in 2021 and 2022 following the
12 downturn in construction in 2020 from Covid-19", page 115 lines 7-9, is
13 unfounded. AG Witness Coppola does not offer any evidence to support his claim
14 that the forecast activity is driven by a post Covid-19 surge in 2021 or 2022. In
15 discovery response to AGDE-4.144a, presented in Witness Coppola's testimony
16 and exhibits as AG-44 CONF (which includes DR AGDE-4.144a with Confidential
17 attachment), the Company provided an Excel file that showed actual volume from
18 2023 and 2024, with a projection to 2025 and 2026. From 2023 to 2024 the
19 Company experienced a 2.2% increase in staking and location requests. Based on
20 this increase the Company forecasted a 2.4% and 3.2% increase for 2025 and 2026,
21 respectively.

22
23 Additionally, the current run rate for electric staking requests through August 2025,
24 the Company, and the State of Michigan, is on pace to set a historic record for ticket
25 volume.

Line
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1 **Q69. Specific to AG Witness Coppola’s third assertion, is the contractor cost**
2 **associated with staking and locating justified?**

3 A69. Yes. First, as a reminder, DTE Electric contracts all staking and locating services.
4 Second, the Company’s contractor cost for staking and locating is based on the
5 results of a competitive request for proposal (RFP) bidding process. After vendor
6 negotiations, the contracts reflect the current labor and materials market prices for
7 this type of specialized work. AG Witness Coppola does not offer any support for
8 his claim that the 41% increase in contractor cost from 2023 to 2026 is “exorbitant.”

9

10 **Q70. Should the Commission adopt AG Witness Coppola’s recommended reduction**
11 **associated with Staking and Locating?**

12 A70. No. AG Witness Coppola provides no support for his proposed reduction of the
13 Staking and Locating adjustment. The Company’s funding request is based on
14 documented operational requirements to perform work as required by Public Act
15 174. Accordingly, the Commission should reject AG Witness Coppola’s
16 recommendation.

17

18 **Q71. Does this conclude your rebuttal testimony?**

19 A71. 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

REBUTTAL TESTIMONY

OF

RACHEL C. STEUDLE

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF RACHEL STEUDLE

Line
No.

1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed?**

3 A1. My name is Rachel Steudle. My business address is One Energy Plaza, Detroit,
4 Michigan 48226. I am employed by DTE Electric Company as the Director of Tree
5 Trimming within the Distribution Operations department.

6
7 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
8 **Company (DTE Electric or Company)?**

9 A2. Yes.

10

11 **Purpose of Testimony**

12 **Q3. What is the purpose of your rebuttal testimony?**

13 A3. The purpose of my rebuttal testimony is to refute certain positions taken by the
14 other parties as follows.

- 15 • AG Witness Coppola's recommendation to disallow O&M related to the
16 proposed specification change project,
- 17 • Staff Witness Duell's request for a report related to removing softwood
18 overhang which is part of the proposed specification change project,
- 19 • AG-MN Witness Stephens' and AG-MN Witness Alvarez's
20 characterization that the Company has a tree trimming backlog and is falling
21 behind
- 22 • Staff Witness Duell's, MNSC (obo NRDC-CUB) Witness Bunch's and Ann
23 Arbor Witness Stults' recommendation that the Company needs to maintain
24 a fixed, 5-year trimming cycle as opposed to the proposed risk-based cycle
25 approach

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1 The absence of a discussion of other matters in my testimony should not be taken
2 as an indication that I agree with all other aspects of Staff and intervenor testimony.

3

4 **Q4. How is your testimony organized?**

5 A4. My testimony is divided into four parts addressing the bullets above along with an
6 overarching conclusion.

7

8 **Q5. Are you sponsoring any rebuttal exhibits in this proceeding?**

9 A5. Yes. I am sponsoring the following rebuttal exhibits:

<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
A-42	GG1	Discovery Response – MNSCDE-6.7a
A-42	GG2	Proactive Strategies for Utility Vegetation Management_No Outages, No Fires, and No One Gets Hurt

15

16 **Part 1 - Proposed Specification Change Project**

17

18 **Q6. Which intervenors provided commentary related to the Company's proposed**
19 **specification change project?**

20 A6. Staff Witness Duell and AG Witness Coppola both provided commentary on the
21 specification change project, specifically related to the \$35 million requested by the
22 Company. Further, Witness Duell recommended reporting related to one part of the
23 project.

Line
No.

1 **Q7. How does the proposed specification change project fit into the Company’s**
2 **overall strategy and plan for 2026?**

3 A7. In 2026, the Company intends to maintain the current Enhanced Tree Trimming
4 Plan (ETTP) Specification as the Base Plan, while strategically introducing
5 incremental and expanded trimming for a portion of the 2026 maintenance plan.

6
7 **Q8. What are the specific changes the Company is proposing?**

8 A8. As discussed in my direct testimony, beginning on page 21, line 23, the Company
9 has identified three areas to change:

- 10 1) Remove species-specific overhang
11 2) Improve clearing of the “floor”
12 3) Establish an outside-the-right-of-way (OROW) Tree Risk Program

13
14 **Q9. How are these changes measurably different and incremental compared to the**
15 **ETTP Specification?**

16 A9. Each of these proposed changes would result in the Company trimming and/or
17 removing more vegetation near and around the Company’s overhead infrastructure.
18 Table 1 demonstrates the measurable change to the specification for each area.

Line
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1 **Table 1 Comparison of ETTP Specification and Proposed Changes**

	ETTP Specification	Incremental Change
Refine Overhang Efforts	- Remove overhang to the first protective device (Zone 1) covers ~20% of circuit miles - The remaining ~80% of the miles overhang is trimmed to obtain 10' aerial clearance and 45-degree branches above	- Remove species-specific overhang on <u>all distribution zones</u> - At full-scale, would increase overhang removed on approximately 200-thousand trees annually
Improve Clearances of the "Floor"	- Average removal rate is ~50% for brush and ~20% for trees - About half the ideal removals are completed annually – trimming is completed when a removal does not occur	- Increase focus on removing brush and small trees through changes to process - Target to remove ~100% brush and ~90% small tree
Establish an OROW Tree Risk Program	- Identify dead/dying trees OROW during maintenance trimming, removals require customer permission - Accounts for ~1% of annual spend	- Increase the distances outside the right-of-way the Company identifies as hazard trees – expand the distance from 25' to 50' - Separate this workstream from the maintenance program

2

3 **Q10. Does the Company believe these changes will provide incremental benefits to**
4 **customers?**

5 A10. Yes. The Company believes these changes will provide incremental reliability and
6 resiliency benefits. In addition, the Company expects these changes to yield future
7 cost savings. Further discussion of the benefits can be found on pages 23 through
8 26 of my direct testimony.

9

10 **Q11. Do these changes align with the feedback from the Liberty Audit?**

Line
No.

1 A11. Yes. The Liberty Audit noted the opportunity to increase the Company's focus on
2 OROW trees, and "supports enhanced trimming and clearing methods"¹ such as
3 clearing the floor and species-specific overhang.
4

5 **Q12. Did the Commission provide commentary on this topic in its Order in Case**
6 **No. U-21305?**

7 A12. Yes. "The Commission finds that DTE Electric should analyze the incremental
8 costs and benefits of expanding trimming zones and of clearing underbrush and
9 hazard trees, as recommended by the Staff."²
10

11 **Q13. How much funding is the Company requesting to support the introduction of**
12 **these changes in its 2026 plan?**

13 A13. The Company is requesting \$35 million in O&M above the base plan of \$145
14 million. The \$35 million will be used to strategically implement these specification
15 changes on circuits already on the maintenance plan. The Company will leverage
16 this work to collect data on customer sentiment, contractor productivity, and
17 reliability improvements related to these changes to better understand the
18 incremental costs and benefits to implement at full-scale.
19

20 **Q14. How was the \$35 million request developed and did the Company provide**
21 **detailed breakdown?**

22 A14. The \$35 million was developed using the Company's historical cost and tree data,
23 along with input from Company field personnel and a third-party consultant. The

¹ Case No. U-21305; Liberty Audit, Part Two, pg. 53

² Case No. U-21305 Order dated June 12, 2025, p. 17

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1 Company provided a detailed breakdown of how much money would be spent on
2 each of the proposed changes in discovery AG-6.201a, including a spreadsheet with
3 intact formulas. A key input to the cost estimates was the historical data from the
4 Company's work management system which includes data on each tree touched
5 since the beginning of the Surge.

6

7 **Q15. Did intervenors provide support for the proposed specification change project**
8 **and the \$35 million request?**

9 A15. Yes. Staff Witness Duell recommends that the Commission approve the full \$180
10 million request, which includes the \$35 million earmarked for the specification
11 change project.³

12

13 **Q16. Did others provide similar support?**

14 A16. Yes. AG Witness Coppola on the whole supported the proposed specification
15 change project, but did recommend some disallowances within the \$35 million
16 request. "I recommend that the Commission remove [\$8.322 million] from the Tree
17 Trimming special program of \$35 million and reduce that amount to \$26,716,000
18 on top of the \$145 million base program."⁴

19

20 **Q17. Why does Witness Coppola recommend a \$8.322 million disallowance for the**
21 **specification change project?**

22 A17. Witness Coppola states a portion of the costs in the \$35 million request are
23 duplicative and redundant to the costs included in the Company's base plan.
24 Specifically, he claims that the following items are duplicative:

³ Witness Duell Direct, p. 6 line 21 through p. 7 line 4.

⁴ Witness Coppola Direct, p. 112 line 15-17

Line
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1 1) Inspection and planning of trees outside the right-of-way (OROW) (\$3.5
2 million)

3 2) Customer outreach and call center (\$2.5 million)

4 3) Small tree removals (\$2.3 million)

5

6 **Q18. Do you agree those costs are redundant and should be disallowed?**

7 A18. No – these costs are incremental to the Company’s proposed base plan and are
8 necessary to fully support the specification change project.

9

10 **Q19. Can you elaborate on the OROW inspection costs?**

11 A19. Yes. The incremental cost for inspecting and planning OROW trees is needed
12 because the Company is significantly increasing the number of trees it will target
13 and remove in 2026. The Company is doubling the distance outside the ROW that
14 are identified as at-risk trees, incorporating these inspections into the midcycle
15 inspections, and leveraging certified arborists to assess tree health and risk of
16 failure. The Company projects to remove 200% more OROW trees compared to the
17 base plan.

18

19 The planning and inspection costs reflect the significant increase in time spent
20 identifying these trees and then working with homeowners to gain permission to
21 remove the trees. The increase in the distance the Company is identifying OROW
22 trees will require field personnel to take incremental time looking at the vegetation
23 alongside Company infrastructure compared to the current process. The Company
24 also expects these field personnel to take additional time identifying indicators of
25 tree health, such as “sounding the tree” to test for internal decay and/or seeing
26 mushrooms or fungus growing along the base of the tree. Once the tree is identified

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1 as a priority for removal, the inspectors will need to communicate with the
2 homeowners. The Company's experience through the Surge has demonstrated the
3 importance of face-to-face communication and engagement to gain permission to
4 remove trees. The Company expects homeowners will have even greater hesitation
5 and concerns over OROW trees being removed because these trees are outside the
6 Company's easement and typically larger, established trees. The time required to
7 gain customer permission is included in the \$3.5 million. Overall, the \$3.5 million
8 breaks down to about \$250 per tree to inspect and then plan for removal.

9

10 **Q20. Why is the Company seeking \$2.5 million for additional customer outreach?**

11 A20. At the core of specification change project is the intent to remove more vegetation
12 (branches, brush and full trees). The Company anticipates the increase in vegetation
13 being removed will lead to an increase in customer escalations, inquiries and
14 complaints. The Company's current call center will need increase staffing levels to
15 handle the increased call volume. In addition to reactive management of customer
16 concerns, the Company is identifying ways to increase its education and proactive
17 communication to customers around the tree trimming program and benefits of
18 vegetation removal. This funding will also go toward supporting these efforts.

19

20 **Q21. How is the \$2.3 million for small tree removals incremental to the base plan?**

21 A21. The base plan was built on historical cost per mile and tree removal data. The
22 Company has identified ~175,000 trees it would like to remove annually that were
23 trimmed during the Surge. The \$2.3 million reflects the incremental cost to remove
24 those trees compared to trimming them again. The cost built into the historical data
25 and therefore in the base plan reflects trimming these trees as opposed to removing.

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1 The cost to remove a tree is greater than trimming because more time is needed to
2 fully remove the tree as opposed to just addressing a portion of it. The \$2.3 million
3 is based on removing these trees and is an incremental 25%-40%⁵ compared to
4 historical trimming costs.

5

6 **Q22. Did others provide specific recommendations with respect to the specification**
7 **change project?**

8 A22. Yes, Witness Duell proposed the Company provide a study with respect to the
9 removal of softwood overhang.

10

11 *Staff recommends the Company provide a report within two years of the*
12 *completion of this rate case on softwood overhang removal. The*
13 *following data should be included in the report: how much softwood*
14 *overhang was cleared each year since beginning this practice (in miles*
15 *or another appropriate unit), how much zone 1 overhang was removed*
16 *over those same years, how many outages occurred due to overhang*
17 *damage, and, lastly, the change in all-weather SAIDI and SAIFI due to*
18 *softwood overhang removal. Staff recommends this report be filed within*
19 *two years of the completion of this rate case (Direct Testimony Witness*
20 *Duell, page 9, line 18-24).*

21

22 **Q23. Does the Company agree with this request?**

23 A23. The Company is supportive of this request; however, it would like to collaborate
24 with the MPSC Staff to refine the proposed study. Specifically, the Company feels
25 it is important to consider the benefits and cost of the proposed overhang expansion
26 along with the other two proposed changes to the specification. Therefore, the
27 Company feels it is best to develop a study and way to evaluate the cost/benefit of
28 the specification change project holistically.

⁵ Range is based on size of the tree – within the work management system we have specific size classes to estimate the volume of different sized trees

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1 **Part 2 - Completion of Surge – Backlog Mitigation**

2 **Q24. In reference to DTE's vegetation management backlog, both Witness Stephens**
3 **and Witness Alvarez (AG-MN) state that the Company appears to have fallen**
4 **further behind in 2023 and 2024 and appears likely to fall even further behind**
5 **in the 2025-2028 period.⁶ Do you agree with this statement?**

6 A24. No. As I stated on page 7 of my U-21860 direct testimony, DTE Electric brought
7 its system to 92% on-cycle at the end of 2024 with the goal to be 100% on-cycle
8 by the end of 2025.

9

10 **Q25. Witnesses Stephens and Alvarez both appear to draw their conclusions based**
11 **on Figure 4 in Stephens U-21860 direct testimony on page 19 titled "Vegetation**
12 **Management miles completed by year relative to the amount required to**
13 **achieve a 5-year cycle." Is this chart accurate?**

14 A25. No, it does not appear to be accurate. Witness Stephens sets his annual requirement
15 (presumably distribution miles the Company must trim each year to remain on a
16 fixed 5-year cycle) at approximately 6,500. The Company in fact has approximately
17 28,600 distribution circuit miles and should instead have shown 5,700 miles as the
18 annual requirement in Witness Stephens chart if using a fixed 5-year cycle. Further,
19 the actual miles the Company has trimmed/plans to trim is not accurate for 2025
20 and onward. Therefore, the conclusions drawn by Witnesses Stephens and Alvarez
21 that rely on Stephens table in Figure 4 suggesting the Company will fall further
22 behind in its trimming is incorrect and should be disregarded by the Commission.

⁶ Stephens U-21860 Direct Testimony, p. 18; Alvarez U-21860 Direct Testimony, pp. 10-11

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No.

1 **Q26. Are there other inaccuracies or misrepresentations made by Witnesses**
2 **Stephens and Alvarez with respect to the Company having a backlog related**
3 **to tree trimming?**

4 A26. Yes. Overall, the Company has consistently referred to the backlog as the portion
5 of miles not yet trimmed to our ETP specification and therefore considered off-
6 cycle. As already mentioned, as of September 2025, the Company is on track and
7 ahead of schedule to be 100% complete with the Surge by the end of this year. By
8 completing the Surge, the Company will have no remaining off-cycle miles and no
9 backlog with respect to tree trimming.

10

11 It appears Witnesses Stephens and Alvarez are conflating maintaining a strict, 5-
12 year trimming cycle, or lack thereof, with creating a backlog. As discussed
13 extensively in my direct testimony, and addressed further below, the Company is
14 transitioning to a more sophisticated, risk-based cycle. This concept has been
15 introduced and discussed by the Company as the intended direction for the last two
16 rate cases (U-21297⁷ and U-21534⁸) and was originally a recommendation by a
17 prior MNSC Witness, Robert Ozar, in 2022.⁹

18

19 **Part 3 - Recommended Maintenance Trimming Cycle**

20 **Q27. Can you summarize the position of intervenors with respect to trimming**
21 **cycles?**

22 A27. Yes. Witness Duell (Staff), Witness Stults (Ann Arbor), and Witness Bunch
23 (NRDC-CUB) oppose the Company's proposed shift toward a risk-based cycle in

⁷ Hartwick, U-21297 Direct Testimony, pp 39-44

⁸ Steudle, U-21534 Direct Testimony, pp. 28-32

⁹ Ozar, U-20836 Direct Testimony, pp. 77-81

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1 favor of remaining on a fixed 5-year cycle. Witness Duell raises the concern that
2 “extending some line miles to cycles that are 6 or 7 years may result in the Company
3 experiencing an increase in vegetation which could cause an increase in trimming
4 backlog.”¹⁰ Witness Stults contends that “DTE’s plan to purposefully fall behind a
5 5-year cycle on over half of its circuit miles immediately following the Surge
6 ignores the Audit’s findings and recommendations...”¹¹ Lastly, Witness Bunch
7 contends that “[n]o new information has surfaced since the Commission’s order on
8 June 12th, 2025” and “maintain the five-year trim cycle for all circuits.”¹²

9
10 **Q28. What was the basis used for this justification?**

11 A28. The basis for both objections to moving toward a risk-based approach appear to
12 hinge on the comment from Order U-21305 that states on page 17:

13 *At a minimum, the Commission does not want to lose the progress that*
14 *has been made by achieving the five-year tree trimming cycle. The*
15 *Commission recommends that the company stay on the five-year cycle*
16 *while investigating the additional benefits of moving to a four-year*
17 *cycle, consistent with Liberty’s recommendation and finding that*
18 *“others have commonly found [] additional reliability benefits on a*
19 *cost effective basis.*

20 Holistically, “The Commission adopts the findings and recommendations of the
21 Liberty Consulting Group’s September 23, 2024 Final Report, Utility Distribution
22 Audit of DTE Energy Part One and Part Two, as discussed above.”¹³

23
24 **Q29. Can you summarize the Liberty Audit Report with respect to tree trimming**
25 **and trimming cycles?**

¹⁰ Duell, U-21860 Direct Testimony, p.8

¹¹ Stults, U-21860 Direct Testimony, p. 9

¹² Bunch, U-21860 Direct Testimony, pp. 28-29

¹³ Commission Order U-21305, dated June 12, 2025, page 51

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1 A29. Yes. The Liberty audit report provides insightful information in sections titled:
2 *Trim Miles and Costs, Conclusions*, and most importantly, *Recommendations*, as it
3 relates to the Company's risk-based approach:

4
5 Trim Miles and Costs¹⁴

6 *Shortening the five-year distribution cycle to a four-year cycle would*
7 *increase costs. A four-year cycle will require treating an additional*
8 *1,400 miles per year, which would produce added annual costs in the*
9 *range of \$40 to \$50 million. While difficult to calculate, the lesser*
10 *overgrowth that will occur between treatment on a four-year cycle will*
11 *serve to reduce that annual incremental cost.*

12
13 Conclusions¹⁵

14 *We found the five-year tree trimming cycle consistent with good practice,*
15 *but it is not clear that reducing it by another year or so would not add,*
16 *as others have commonly found, additional reliability benefits on a cost*
17 *effective basis. While the five-year cycle establishes a sound baseline for*
18 *now, given the many other needs DTE faces in securing substantial*
19 *reliability improvements, its plan to examine cycle alterations should*
20 *remain a priority.*

21
22
23 Recommendations¹⁶

24 *Trees remain a major contributor to SAIDI minutes as the surge in*
25 *treatment has continued. The shorter cycles and enhanced methods now*
26 *in place should continue, and, if they do, will continue to make such a*
27 *contribution. The question that requires examination is whether they can*
28 *do more at effective cost if shortened for certain areas. DTE plans to*
29 *study further cycle changes, seeking to optimize the balance between*
30 *reliability results and the costs to achieve them. Using information*
31 *gained through controlled analysis of post treatment results and*
32 *consideration of the unique and incremental impacts of other reliability*
33 *enhancing measures, management should complete its study of cycle*
34 *changes as soon as it can.*

¹⁴ Final Report Utility Distribution Audit of DTE Energy – Part Two, p. 52, September 23, 2024

¹⁵ Id.

¹⁶ Final Report Utility Distribution Audit of DTE Energy – Part Two, p. 53, September 23, 2024

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1 **Q30. Do you believe the Company *is following* the recommendations of the Liberty**
2 **Audit in moving toward a risk-based approach?**

3 A30. Yes. The Company remains committed to maintaining an effective tree trim
4 program that aligns with both the Liberty conclusions and recommendations above,
5 as well as the Commission's order in Case No. U-20836. As I noted on page 16 of
6 my direct testimony in the instant case, the Commission ordered the Company to
7 continue to explore efficiency improvements and benefits from a variable cycle for
8 the Tree Trimming program. Witness Stults asserts that the Company's shift to a
9 risk-based approach is "an excuse to fall behind its promised 5-year cycle on some
10 circuits and not to test the efficacy of trimming higher risk circuits more often."¹⁷
11 The reality is the risk-based approach enables the Company to do exactly what she
12 and others desire, shorten the cycle length for some circuits. As shown on in the
13 table on page 20 titled "Risk-Based Trim Cycle" from my direct testimony in the
14 instant case:

Circuit Type	Cycle Length (Years)	% of Customers	% of System Miles
Sub-transmission	3	N/A	8%
Distribution	4	37%	17%
Distribution	5	30%	20%
Distribution	6	21%	19%
Distribution	7	12%	36%

15

16 **Almost 40% of DTE's customers reside on circuits that will move to an**
17 **accelerated 4-year cycle** under the Company's proposal, who would otherwise
18 have stayed on a 5-year cycle. When including those customers whose circuits will
19 remain on a 5-year trim cycle (30%), **over two-thirds of customers will be on**
20 **circuits with a 4 or 5-year trim cycle.**

¹⁷ Stults, U-21860 Direct Testimony, p. 8

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1 **Q31. Please explain in detail how the Company is in alignment with Liberty’s**
2 **recommendations noted above and exploring the efficiency improvements**
3 **ordered by the Commission in Case No. U-20836?**

4 A31. The LiDAR data that the Company acquired in 2021, combined with the tree
5 species that the Company has cataloged during the Surge was used to develop its
6 risk-based model. In line with Liberty’s recommendation for the Company to
7 “complete its study of cycle changes as soon as it can” in reference to optimizing
8 the balance between reliability results and the costs to achieve them, the model was
9 used to make adjustments to the Company’s 2024 and 2025 tree trimming plans.

10

11 To that end, the model was used to defer approximately 2,000 “on-cycle miles from
12 2024 and 3,700 “on-cycle” miles from the 2025 plan. As noted in my direct
13 testimony on page 19, the results of these deferrals were promising. The SAIFI for
14 circuits deferred in 2024 was 0.15 while the overall system SAIFI was 0.18. In other
15 words, the results of these deferred circuits were on par with the system average for
16 2024.

17

18 **Q32. Why is the Company proposing a full shift to risk-based approach in 2026?**

19 A32. Thus far, the Company has been exploring the efficiency and benefits/risks of
20 variable cycles as it pertains to deferring circuits to longer trimming cycles. This
21 approach over the last two years has enabled the Company to understand the upside
22 risk of variable cycles. With the Surge being completed in 2025, next year provides
23 the chance to start shortening cycles as well. Moving into 2026, the Company’s
24 proposed test year budget of \$180 million includes trimming *all* circuits based on

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1 their unique risk profiles, inclusive of now pulling ahead, and shortening the cycle
2 length for over a third of the Company's customers.

3

4 **Q33. With this approach in 2026, will DTE Electric "fall behind a 5-year cycle on**
5 **over half its circuit miles" as Witness Stults asserts in her direct testimony?**

6 A33. No. The premise that Witness Stults uses is flawed for two reasons. First, the
7 Liberty audit did not provide an endorsement of 4- or 5-year tree trimming cycle as
8 an end point as Stults seems to indicate on page 9 of her direct testimony, but should
9 be interpreted instead as a step toward a more mature and refined tree trim program,
10 which is DTE's intended outcome in utilizing its risk-based approach. Targeting
11 circuits based on their unique risk profiles that allow for longer trim cycles is a
12 feature of the model, not a flaw. Further, Witness Stults mis-characterizes Liberty's
13 comment that "most utilities rely on a 4-year trimming cycle for distribution
14 voltages."¹⁸ Instead, Liberty presented this as a data point in a section of its report
15 titled "Reliability Comparisons & Vegetation Spending." It was not intended to
16 form a conclusion that DTE Electric should adopt a similar trim cycle for all of its
17 distribution circuits.

18

19 Second, the Liberty Audit suggests there may not be a discernable reliability benefit
20 associated with the incremental cost in moving from a 5-year cycle to a 4-year
21 cycle. Interestingly, Witness Stults correctly quoted Liberty in its observation that
22 moving from a 5- to 4-year trimming cycle "*would not add, as others have*
23 *commonly found, additional reliability benefits on a cost effective basis.*"¹⁹

¹⁸ Final Report Utility Distribution Audit of DTE Energy – Part One, p. 5, September 23, 2024

¹⁹ Stults, U-21860 Direct Testimony, p. 8

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1 Beginning in 2026, the Company will be able to collect data and test the
2 effectiveness of shortening cycles for some circuits.

3

4 **Q34. Does it stand to reason that trimming circuits more frequently, e.g., at 4- or 5-**
5 **year intervals will inherently improve reliability?**

6 A34. Not necessarily. As I discussed extensively in my testimony, trimming on a fixed
7 5-year cycle disregards unique characteristics of the Company's system circuits and
8 species growth profiles. With the emergence of technologies such as LiDAR and
9 data analytics now available, utilities that are mature in their vegetation
10 management approach, are now able to strategically and cost effectively address
11 vegetation risk. Over the last decade when DTE Electric first acknowledged that it
12 was off cycle, the Company's first objective was to formally introduce its enhanced
13 specification for trimming (Enhanced Tree Trim Program, or ETP) and begin the
14 reclamation process, followed then by the "Surge" program to fully reclaim all of
15 its line miles. Most circuits at the outset of the Surge were off-cycle and the goal
16 crystallized to fully address that backlog as quickly as possible.

17

18 Therefore, the next logical step is to strategically employ the use of this technology
19 to continue on this journey to trim efficiently and cost effectively (trimming the
20 right miles at the right time). Conversely, blind adherence to a fixed number of
21 miles each year disregards the use of this technology and data that was not available
22 a few short years ago.

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1 **Q35. Witness Stults states that “some circuits will be trimmed as infrequently as**
2 **every 7 years.”²⁰ Does this mean DTE Electric will not perform any trimming**
3 **or inspections on circuits recommended for longer trim cycles?**

4 A35. No. The Company recognizes and anticipates the need to maintain the necessary
5 clearances and address cycle-buster trees, especially for longer trim cycles. As I
6 highlighted in my direct testimony, the Company will put in place a mid-cycle
7 inspection program in which a portion of the distribution circuits are inspected 2-3
8 years post trimming.²¹ This will allow for the Company to identify and proactively
9 perform hot-spot trimming where needed.

10

11 **Q36. How many miles annually would the Company need to trim to maintain a 4-**
12 **and 5-year cycle compared to the proposed risk-based plan?**

13 A36. See Table 2 below which shows the number of miles annually the Company would
14 need to trim to maintain a 4- and 5-year cycle.

15 **Table 2 Annual miles to maintain 4- and 5-year cycle**

Voltage	4 - Year	5 - Year	Risk-Based (5.8-Years)
Distribution	7,142	5,714	4,913
Subtransmission	840	840	840
Total	7,982	6,554	5,753

16

17 **Q37. What additional funding would the Company likely need if it were to adopt**
18 **either a 5- or 4-year fixed trim cycle?**

19 A37. The Company produced this analysis during audit and discovery²². The
20 incremental cost in moving from a 5.8 year average risk-based trim cycle to a fixed

²⁰ Stults, U-21860 Direct Testimony, p. 6

²¹ Steudle, U-21860 Direct Testimony, p 21

²² U-21860 Exhibit A-42 Schedule GG1 – Discovery Response – MNSCDE-6.7a

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1 5-year trim cycle was estimated to be at minimum an incremental \$20 million
2 dollars more than the Company's current \$180 million request for 2026. As noted
3 in their report, Liberty then estimates an additional \$40 to \$50 million dollars in
4 moving from a 5- to 4-year trim cycle.

5

6 **Q38. Does it stand to reason that with increased spending to accomplish more miles,**
7 **comes increased reliability?**

8 A38. Not necessarily. The proposed base plan for next year will be \$145 million, which
9 is based on an average cycle length of 5.8 years. Incremental to the base, the
10 Company is requesting additional funding to introduce the specification change
11 project. The Company believes that incremental funding in the tree trimming
12 program specific to those changes is a more prudent investment than incremental
13 funding to maintain a fixed 4- or 5-year cycle.

14

15 **Q39. Is DTE Electric now taking the position that a 5-year fixed trim cycle is not a**
16 **useful way to maintain reliability?**

17 A39. Not at all. DTE Electric understands that building a resilient, long-term tree
18 trimming program is an evolving journey. Over a decade ago, upon recognizing it
19 was off-cycle, the Company launched the Enhanced Tree Trim Program (ETTP) to
20 establish enhanced trimming standards and target system-wide reclamation. This
21 effort was followed by a six-year "Surge" initiative to reclaim all line miles, during
22 which DTE Electric began collecting critical data, deploying LiDAR, and
23 integrating data analytics.

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1 Now, the next strategic phase is to use these technologies to guide decision-making,
2 optimize funding, and allocate resources more effectively. From the outset, ETTP
3 aimed to achieve a 5-year on-cycle standard—then the industry benchmark. As
4 technology has advanced, so too has DTE’s approach. Stated best by Stephen
5 Cieslewicz, Founder and Principal Consultant of UVM (utility vegetation
6 management company) in his report “Proactive Strategies for Utility Vegetation
7 Management: No Outages, No Fires, and No One Get’s Hurt”²³:

8

9 *Fixed cycles became standard because utilities historically lacked the*
10 *tools to track vegetation dynamically. Without digital inventories or*
11 *predictive analytics, they could not accurately assess growth rates,*
12 *detect disease, or adjust for environmental stressors. Today, these tools*
13 *exist, allowing utilities to prioritize high-risk areas and respond*
14 *proactively. However, many still rely on outdated schedules, failing to*
15 *consider key factors such as tree species, climate variability, and soil*
16 *conditions. Some trees may require pruning every few years, while*
17 *others pose a risk within a single season. Without up-to-date*
18 *inventories and risk assessments, utilities misallocate resources and*
19 *struggle to prevent emerging threats.*

20

21 **Q40. Please expand on where else in the industry, a risk-based model is being used**
22 **or advocated for?**

23 A40. As I mentioned in my direct testimony in the instant case, it is the Company’s
24 understanding that other utilities in the industry are exploring specifically or
25 introducing, risk-based variable cycles.

26

27 **Q41. Could you please summarize your position on DTE’s shift to a risk-based**
28 **approach?**

²³ U-21860 Exhibit A-42 Schedule GG2 – Proactive Strategies for Utility Vegetation Management: No Outages, No Fires, and No One Gets Hurt, p53-54

Line
No.

1 A41. Yes. There are 3 key takeaways to note:

2 1) A risk-based approach allows the Company to strategically select
3 circuits based on their unique risk profiles that better allow for a more
4 efficient and effective trimming strategy. In other words, this approach
5 intends to avoid trimming too soon (not cost effective), or too late
6 (incurring outage/reliability risk), which a fixed 5-year trim cycle does
7 not contemplate.

8 2) The Company has been on the path and signaling its intent to shift to a
9 risk-based cycle since 2022. In line with the interest of intervenors and
10 the Commission, the Company has been exploring the efficiency and
11 benefits/risks of variable cycles during this time, providing compelling
12 data on its benefits. The proposed plan for 2026 is the natural evolution
13 and maturation of the program.

14 3) The Company is in line with both Liberty's audit recommendations as
15 well as best-in-class industry standards in shifting to a data driven
16 approach. As part of this shift, the Company is also incorporating a
17 formal mid-cycle and spot trimming program to identify emergent
18 threats for circuits that are recommended for longer cycles.

19

20 **Part 4 – Concluding Commentary**

21 **Q42. Are there any final themes that emerged in intervenor testimony that you**
22 **would like to address?**

23 A42. Yes, witnesses for both Ann Arbor and MNSC implied that the Company's
24 proposed 2026 neglects tree trimming and that the Company intends to "fall back"

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1 on progress gained by the Surge. Further, these witnesses suggest that Company is
2 moving toward a similar investment level to pre-Surge years.²⁴

3

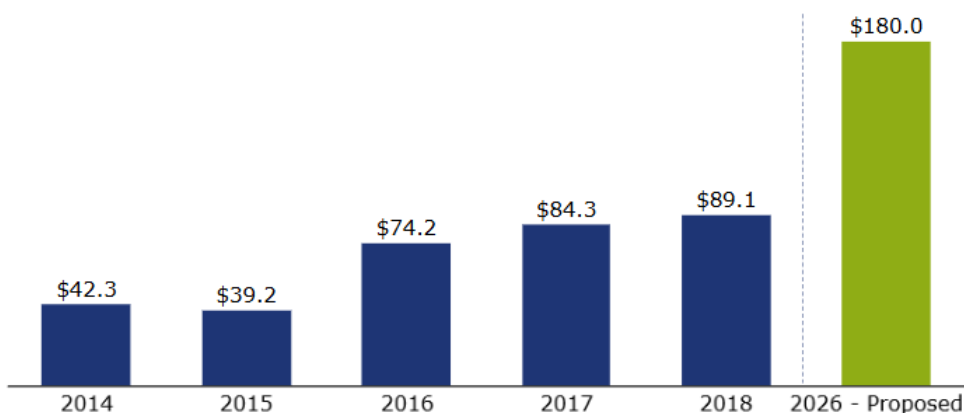
4 **Q43. Do you agree with this characterization?**

5 A43. No. While the risk-based approach will relatively cost less than a 5-year cycle, the
6 Company is proposing to maintain a significantly higher base budget than has ever
7 been historically forecasted for post-Surge. Further, the Company has identified
8 incremental areas it would like to invest additional trimming and has requested \$35
9 million to support that effort. Overall, the Company's requested funding for 2026
10 is in line with investment levels during the Surge, and over 170% greater than pre-
11 Surge (2014-2018) investments as demonstrated in Figure 1 below:

12

Figure 1

Pre-Surge Annual funding (in \$M) vs Post-Surge Annual Funding



13

14 **Q44. Can you summarize the Company's recommendations as they relate to the**
15 **arguments and recommendations made in Staff and intervenor testimony?**

16 A44. The Company recommends that the Commission:

²⁴ Ann Arbor Witness Stults page 7, line 11-16; MNSC Witness Bunch page 28 line 12-16

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1 1) Approve the Company's requested \$180 million dollars including its expanded
2 specification initiative of \$35 million dollars. The Commission should disregard
3 witness Coppola's assertion that \$8.3 million dollars are duplicative and included
4 in its' base O&M request.

5 2) Fully support the Company's risk-based approach as presented in witness
6 Steudle's U-21860 direct testimony. The Company's test year funding request is
7 predicated on the adoption of this strategy, and as discussed extensively in this
8 rebuttal, is in line with the Liberty audit recommendations as well as supported by
9 industry experts.

10

11 **Q45. Does this conclude your rebuttal testimony?**

12 A45. 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

REBUTTAL TESTIMONY

OF

CHRISTOPHER J. HARTLEY

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF CHRISTOPHER J. HARTLEY

Line
No.

1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed?**

3 A1. My name is Christopher J. Hartley (he/him/his). My business address is 8001
4 Haggerty, Belleville, Michigan 48111. I am employed by DTE Electric Company
5 (DTE Electric or Company) as Manager of Business Development & Support for
6 Community Lighting.

7
8 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric?**

9 A2. Yes.
10

11 **Q3. Are you sponsoring any rebuttal exhibits in this proceeding?**

12 A3. No.
13

14 **Purpose of Testimony**

15 **Q4. What is the purpose of your rebuttal testimony?**

16 A4. The purpose of my rebuttal is to address the following intervenor positions:

17

18 Michigan Municipal Association for Utility Issues (MI-MAUI) and The Michigan
19 Coalition to Protect Public Rights-Of-Way (PROTEC), Witness Schultz

- 20 1) Proposal that the Company be directed to implement a policy change
21 requiring proactive conversion of all mercury vapor (MV) fixtures to LED;
22 2) Recommendation that the Commission disallow \$70,770 of O&M
23 associated with Post-Inspection and Post-Painting preventative
24 maintenance programs;

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1 3) Proposal that the Commission disallow \$684,315 of Supervisory and
2 Administrative expenses included in the Company's Community Lighting
3 O&M budget.

4 Michigan Public Service Commission (MPSC) Staff (Staff), Witness David Isakson

5 4) Recommendation that the Company file a proposal for universal lighting
6 rates in its next rate case.

7

8 **Summary of Recommendations**

9 **Q5. Please summarize your conclusions, recommendations, and Company**
10 **positions to the Commission.**

11 A5. My summary of conclusions, recommendations, and Company positions is outlined
12 below. The absence of discussion on other matters should not be regarded as an
13 indication that I agree with all other aspects of Staff's and intervenor's testimony.
14 Rather, the narrow focus is intended to focus on priority issues in recognition of
15 available resources.

16

17 MI-MAUI Proposals/Assertions

18 1) The Commission should reject the proposal to require the Company to
19 proactively convert the remaining Mercury Vapor (MV) streetlight fixtures
20 under the E1 tariff. Consistent with Commission-approved policy
21 established in Case No. U-18014, MV fixtures are replaced with LED
22 equivalents upon failure, ensuring prudent capital deployment and
23 minimizing rate impacts. Proactive replacement would accelerate cost
24 recovery and likely increase lighting rates. While the Company is open to a

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1 more accelerated timeline with Commission support, a reactive approach
2 remains more equitable and financially responsible.

3 2) The Commission should reject the proposed disallowance of \$70,770 from
4 the Company's preventative maintenance budget for Streetlight Post-
5 Inspection and Post-Painting. The recommendation relies on a narrow
6 inflation-based projection and fails to account for operational realities such
7 as backlog reduction efforts, material cost volatility, and contractor
8 availability. Reducing funding would limit proactive maintenance, increase
9 reliance on reactive repairs, and elevate safety and reliability risks;

10 3) The Commission should reject the proposed disallowance of \$684,315 in
11 Supervisory and Administrative O&M expenses. The recommendation
12 relies on a simplified historical ratio that does not reflect actual operational
13 needs or budgeting practices. The proposed reduction would significantly
14 impair the Company's ability to manage a complex lighting system,
15 affecting staffing, oversight, and maintenance activities, and compromising
16 reliability, safety, and customer service.

17 MPSC Staff Recommendation

18 4) The Company agrees with Staff's recommendation to propose universal
19 lighting rates as part of the next rate case filing.

20

21 **Proposal to Mandate Conversion of Remaining Mercury Vapor Fixtures**

22 **Q6. What is the purpose of your rebuttal regarding the Mercury Vapor (MV)**
23 **fixture conversion proposal by Witness Schultz?**

24 A6. My rebuttal addresses the recommendation from Witness Schultz (MI-MAUI) on
25 page 11, lines 19 – 20 of their direct testimony suggesting that "the Commission

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1 direct the Company to implement a policy change to proactively convert all MV
2 fixtures to LED". I will explain why this proposal is not financially prudent, does
3 not align with current policy, and could result in unnecessary cost burdens for
4 customers.

5

6 **Q7. What is the Company's current policy regarding MV fixture replacement?**

7 A7. Since 2017, in accordance with the Commission's order in Case No. U-18014, the
8 Company has adhered to a policy of replacing MV fixtures with equivalent LEDs
9 only upon failure. This practice ensures functioning MV fixtures are not replaced
10 prematurely, thereby promoting prudent capital deployment while mitigating
11 unnecessary rate increases for customers, and delivering energy-efficient LED
12 lighting upon failure.

13

14 **Q8. How many MV fixtures remain in service, and what progress has been made?**

15 A8. Currently there are approximately 7,100 MV fixtures that remain in service under
16 the E1 Option 1 tariff. This is a 13 percent reduction from the 8,209 fixtures shown
17 on Table 3 of my revised direct testimony in the instant case, demonstrating
18 meaningful progress of replacing MV fixtures with LED luminaires upon failure
19 under the existing policy.

20

21 **Q9. Why does the Company oppose proactive conversion of all MV fixtures?**

22 A9. Proactively converting all MV fixtures would impose an unfunded capital cost
23 estimated between \$1.7 million and \$2.5 million. These costs would be recovered
24 through rates, increasing costs for all lighting customers. Additionally, many MV

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1 fixtures, while past their accounting life, remain operational. Replacing them
2 prematurely would waste usable infrastructure.

3

4 **Q10. Witness Schultz argues in his Direct Testimony on page 7 that MV fixtures are**
5 **fully depreciated (lines 8-9) and no CIAC should be charged (lines 11-14). How**
6 **does the Company respond?**

7 A10. It is not possible to determine how many operational MV fixtures exceed the
8 assumed useful life used for depreciation purposes. The Company utilizes mass
9 asset accounting for lighting assets, which calculates depreciation at the account
10 level rather than for individual assets or subgroups. Consequently, accumulated
11 depreciation is not tracked for specific MV fixtures. Furthermore, the lighting
12 FERC account encompasses multiple fixture types, and applicable depreciation
13 rates have varied over time. Accelerated, proactive conversions of MV fixtures
14 could result in stranded costs.

15

16 With respect to the proposal to exclude Contributions in Aid of Construction
17 (CIAC) for MV conversions, the Company's current policy already avoids CIAC
18 for reactive replacements. The cost of LED conversion upon fixture failure is
19 recovered through rates. Proactive conversions, however, would accelerate capital
20 recovery unnecessarily and shift costs to customers who may not directly benefit
21 from the upgrades.

22

23 **Q11. Is the Company open to accelerating the MV conversion timeline?**

24 A11. Yes. At the current pace, the Company anticipates replacing all remaining MV
25 fixtures within seven years. However, with Commission support, the Company is

Line
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1 willing to commit to a more accelerated timeline of five years, balancing cost-
2 effectiveness with the goal of modernizing the lighting infrastructure.

3

4 **Q12. Witness Schultz references a “vicinity conversion methodology” on page 10,**
5 **lines 14 – 18 in his testimony. Has the Company adopted this approach?**

6 A12. No, the Company has not adopted a vicinity-based replacement methodology.
7 While this approach may offer efficiencies for other utilities that compensate
8 contractors based on time and labor, DTE Electric pays a fixed amount per
9 luminaire based on bid unit pricing. Therefore, whether replacing a single MV
10 luminaire or multiple luminaires in a vicinity, the cost per unit remains
11 approximately the same, and the anticipated efficiencies do not apply.

12

13 Moreover, implementing a vicinity-based replacement strategy would result in the
14 removal of functioning luminaires which are paid at the outage replacement rate.
15 This would lead to overspending in the outage restoration category and potentially
16 impose unnecessary cost burdens on customers. For these reasons, the methodology
17 remains under evaluation but is not part of the Company’s current policy.

18

19 **Q13. How does the Company view MI-MAUP’s goal of aligning rates to cost of**
20 **service (COS) by proactively converting MV fixtures to LED, as explained by**
21 **Witness Schultz beginning on page 5, line 7 of their direct testimony?**

22 A13. The Company supports gradual movement towards COS-based rates, as directed
23 by the Commission. However, forcing immediate MV conversion to accelerate
24 COS alignment would create inequities and financial strain for customers. A

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1 balanced approach of replacing fixtures as they fail or through a Commission
2 supported timeline, as described above, is more equitable and prudent.

3

4 **Proposed Disallowance of Post-Inspection and Post-Painting Program O&M**

5 **Q14. On page 15, lines 12 -13 of his direct testimony, Witness Schultz recommends**
6 **disallowing \$70,770 from the Company's as-filed preventative maintenance**
7 **budget for Streetlight Post-Inspection and Post-Painting. Do you agree?**

8 A14. No. The proposed disallowance is based on a narrow inflation-based projection and
9 does not reflect the full scope of operational needs or cost variability. While
10 inflation is one factor, it is not the only driver of cost increases in these programs.

11

12 **Q15. What other factors contribute to the need for increased funding?**

13 A15. In addition to inflationary pressures, the Company is addressing a substantial
14 backlog of streetlight posts that require painting. This backlog has accumulated
15 over time due to weather-related delays, limited contractor availability, and the
16 prioritization of outage restoration work. Depending on future weather conditions
17 and resource availability, the Company may pursue an accelerated effort to reduce
18 this backlog beginning in 2026, which would necessitate additional funding.

19

20 Moreover, the cost of materials—particularly paint and related supplies—remains
21 volatile. Based on recent communications with the Company's painting contractor,
22 material costs could increase by as much as 15%. These potential cost escalations,
23 combined with the need to maintain system reliability and visual integrity,
24 underscore the importance of securing adequate funding to support the preventative
25 maintenance program.

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1 **Q16. What risks would result from reducing the preventative maintenance budget?**

2 A16. Reducing the budget would limit the Company's ability to proactively inspect and
3 maintain lighting infrastructure, particularly underground-fed posts near roadways
4 that are vulnerable to rust and structural deterioration. This could shift maintenance
5 from planned replacements to reactive repairs, which are less efficient, more costly,
6 and pose greater risks to public safety.

7

8 **Proposed Disallowance of Supervisory and Administrative O&M**

9 **Q17. Beginning on line 13 of page 18, Witness Schultz proposes a disallowance of**
10 **\$684,315 in Supervisory and Administrative O&M based on a historical ratio**
11 **of actual supervisory and administrative costs as a percentage of the total**
12 **direct O&M costs. Is this approach appropriate?**

13 A17. No, the approach proposed by Witness Schultz is not appropriate. From a utility
14 operations and budgeting perspective, basing Supervisory and Administrative
15 (S&A) O&M expenses on a fixed percentage of direct O&M costs from a single
16 historical year oversimplifies the complexities of business management and fails to
17 reflect actual operational needs.

18

19 The 15 percent ratio cited by Witness Schultz assumes a static and proportional
20 relationship between direct and indirect costs. However, this assumption does not
21 align with how Community Lighting develops its budgets or manages its
22 operations. S&A costs are driven by real-world factors such as staffing levels,
23 oversight requirements, program complexity, and the scale of infrastructure being
24 maintained or modernized. These factors are not tied to direct O&M expenditures
25 in a linear fashion.

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1 In short, the Company's projected S&A costs are based on operational realities and
2 forward-looking needs—not on arbitrary historical ratios.

3

4 **Q18. What would be the impact of the disallowance of \$684,315 in Supervisory and**
5 **Administrative costs as proposed by Witness Schultz on page 19, line 8 of his**
6 **direct testimony?**

7 A18. The proposed disallowance of \$684,315 in Supervisory and Administrative (S&A)
8 O&M expenses represents a significant (45%) reduction compared to the
9 Company's five-year (2019 – 2023) historical average spend of \$1.265 million in
10 this category. Such a reduction would have serious operational consequences for
11 the Community Lighting program, which owns and maintains approximately
12 200,000 lighting assets.

13

14 S&A funding supports essential functions such as staffing, oversight, scheduling,
15 contractor coordination, and program management. These activities are critical to
16 maintaining safe, reliable, and responsive lighting infrastructure across the service
17 territory. A cut of this magnitude would directly impair the Company's ability to
18 manage outage restoration, conduct routine inspections, and perform preventative
19 maintenance—all of which are necessary to mitigate equipment failures, ensure
20 public safety, and maintain customer satisfaction.

21

22 Moreover, the scale and complexity of the Community Lighting system requires a
23 dynamic and adequately resourced support structure. Reducing S&A funding based
24 on a simplified historical ratio fails to account for evolving infrastructure demands,
25 regulatory expectations, and service quality standards. If approved, this

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1 disallowance would undermine the Company's ability to meet those obligations and
2 could result in increased risks and diminished service reliability.

3

4 **Q19. Witness Schultz references a total O&M figure of \$4,621,000 in his testimony**
5 **on page 12, lines 13 – 16. Is this figure accurate?**

6 A19. No. The figure cited by Witness Schultz is not accurate. The Company did not
7 provide \$4,621,000 in its direct testimony or in any as-filed exhibit. The correct
8 total test-year O&M amount is \$4,584,000, as shown in Exhibit A-13, Schedule
9 C5.6, line 23. The \$4,621,000 figure referenced by Witness Schultz was sourced
10 from a lighting working model that contained outdated information. Importantly,
11 this figure was included for informational purposes only and was not used in any
12 calculations to determine proposed lighting rates. Therefore, it should not be relied
13 upon for evaluating the Company's O&M projections.

14

15 **Q20. Which O&M amount was used to calculate the proposed lighting rates?**

16 A20. The Company used the correct figure of \$4,584,000 as shown in Exhibit A-13,
17 Schedule C5.6, line 23 to calculate proposed lighting rates.

18

19 **Proposal for Universal Lighting Rates**

20 **Q21. Does the Company support Staff's recommendation, as presented by Witness**
21 **Isakson on page 8, lines 1–15 of his testimony, to file a proposal for universal**
22 **lighting rates in the next rate case?**

23 A21. The Company supports Staff's recommendation to include a proposal for universal
24 lighting rates in its next rate case filing. This approach aligns with broader goals of

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1 rate simplification and transparency, and the Company is committed to working
2 collaboratively with stakeholders to evaluate fair and equitable lighting rates.

3

4 **Q22. Does this conclude your rebuttal testimony?**

5 A22. 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

REBUTTAL TESTIMONY

OF

MARGARET E. GUILLAUMIN

"PUBLIC"

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF MARGARET E. GUILLAUMIN

Line
No.

1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed?**

3 A1. My name is Margaret E. Guillaumin. My business address is One Energy Plaza,
4 Detroit MI, 48226. I am employed by DTE Electric Company (DTE Electric or
5 Company) as Plant Director in the Energy Supply organization.

6

7 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
8 **Company?**

9 A2. Yes.

10

11 **Purpose of Testimony**

12 **Q3. What is the purpose of your rebuttal testimony?**

13 A3. The purpose of my rebuttal testimony is to correct errors and rebut unjustified
14 recommendations for O&M reductions and capital disallowances as recommended
15 by multiple witnesses that provided direct testimony in the instant case. These
16 witnesses include:

- 17 • Michigan Public Service Commission (MPSC) Staff (Staff) Witness
18 Kindschy;
19 • Attorney General (AG) Witness Coppola;
20 • Association of Businesses Advocating Tariff Equity (ABATE) Witness
21 York.

22 The absence of a discussion of other matters in my rebuttal testimony should not
23 be taken as an indication that I agree with all other aspects of any intervenor's
24 testimony.

Line
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1 **Q4. Are you sponsoring any exhibits in this proceeding?**

2 A4. Yes. I am sponsoring the following exhibits:

3 Exhibit Schedule Description

4 A-54 UU1 Discovery Response STDE-4.10

5 A-54 UU2 Discovery Response STDE-4.9c

6 A-54 UU3 Discovery Response STDE-4.9a

7 A-54 UU4 Discovery Response STDE-4.11

8 A-54 UU5 Routine Project Workpapers and Discovery Response
9 STDE-4.5a-b

10 A-54 UU6 Discovery Response AGDE-3.93c

11

12 **Q5. Were these exhibits prepared by you or under your direction?**

13 A5. Yes, they were.

14

15 **Q6. How is your rebuttal testimony organized?**

16 A6. My rebuttal testimony consists of the following three (3) parts:

17 Part I Rebuttal of Witness Kindschy's Recommended O&M Reductions

18 Part II Rebuttal of Witness Coppola's Recommended O&M Reductions

19 Part III Rebuttal of Witness Coppola's and Witness York's Capital Disallowance
20 Recommendations

Line
No.**Part I – Rebuttal of Witness Kindschy’s Recommended O&M Reductions****Witness Kindschy’s O&M Reduction to One-time 2026 Expenses**

Q7. What does Staff Witness Kindschy recommend with respect to the Company’s Steam Power Generation and Other Power Generation O&M requests that she considers to be one-time 2026 expenses that do not continue after 2026?

A7. Witness Kindschy recommends \$15.41 million of O&M reductions for expenses she considers to be one-time 2026 expenses that do not continue after 2026.¹ Her \$15.41 million adjustment includes seven (7) adjustments summarized in Table 1 below.

10

Table 1 Witness Kindschy’s Proposed Reductions Associated with Steam and Other Power Generation One-Time Expenses

12

Witness Kindschy Adjustment Reference	Description	Witness Kindschy’s Proposed One-Time Expense Reduction (\$ million)
Steam – 1 st	Belle River Unit 2 Turbine Support Structure Restoration	\$2.33
Steam – 2 nd	Belle River Startup Study	\$0.25
Steam – 2 nd	Belle River Chemical Resin Replacements	\$0.80
Steam – 2 nd	Belle River Unit 1 Boiler Chemical Clean (portion ²)	\$0.60
Steam – 3 rd	Monroe Reliability Maintenance	\$3.84
Steam – 4 th	Belle River Fuel Handling (portion ³)	\$3.28
Other – 2 nd	Peaker Increased Maintenance	\$4.30
	Total	\$15.41

13

¹ Witness Kindschy DT, pages 6-17.

² Witness Kindschy’s total proposed reduction for the Belle River Unit 1 boiler chemical clean is \$3.0 million. \$2.4 million is related to O&M expenses moving from 2026 to 2027 and \$0.6 million is related to Witness Kindschy considering it a one-time project.

³ Witness Kindschy’s total proposed reduction for Belle River fuel handling O&M is \$5.47 million. \$2.19 million is related to ceasing coal-fired operations the last quarter of 2026 and \$3.28 million is related, in part, to fuel handling costs not being incurred after the projected test year.

Line
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1 **Q8. What is the basis of Witness Kindschy’s proposed \$15.41 million reduction**
2 **related to 2026 expenses that she considers to be a one-time expense?**

3 A8. Witness Kindschy indicates there is no assurance that the Company will file another
4 rate case shortly after this one where the O&M expenses can be reset.
5 Consequently, Staff determined one-time expenses should be recovered over two
6 years to protect rate payers from unreasonable future rates and still provide the
7 utility with recovery of its expenses.⁴ Therefore, for the expenses she considers to
8 be one-time, Witness Kindschy proposes reducing the Company’s requests in half.
9 These 50% adjustment values are shown in the table above, equaling \$15.41 million
10 of the \$31 million that represents the total Company-requested amounts in these
11 categories.

12

13 **Q9. How do you respond to Witness Kindschy’s proposal to recover half of one-**
14 **time O&M expenses in one year and the remainder in a second year?**

15 A9. While I am encouraged that Witness Kindschy supports the O&M requests, her
16 proposal to recover only half the expenses in rates now creates a problematic
17 situation. If the Company files a new rate case shortly after the instant case, it
18 would need to include the other half of expenses not being approved in the instant
19 case to receive full recovery in the next case.

20

21 **Q10. What should the Commission find with respect to Witness Kindschy’s**
22 **recommendation to provide half the recovery of expenses she considers to be**
23 **one-time?**

⁴ Witness Kindschy DT, page 7, lines 9-14.

Line
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1 A10. The Commission should either provide full recovery in the instant case for the
2 O&M requested by the Company that Witness Kindschy considers to be one-time
3 or provide half recovery in the instant case and approve half recovery in the next
4 rate case plus the time value of money from 2026 through 2027, even if the
5 expenses occur in the bridge period of the next case.

6

7 Witness Kindschy's O&M Reduction to Belle River Fuel Supply

8 **Q11. What does Witness Kindschy recommend with respect to Belle River fuel**
9 **handling O&M?**

10 A11. Witness Kindschy recommends a reduction of \$5.47 million in Belle River fuel
11 handling O&M be reflected in 2026 expenses on Exhibit A-13, Schedule C5.1. Her
12 \$5.47 million recommended adjustment is comprised of \$2.19 million associated
13 with the plant ceasing coal-fired operations in the last quarter of 2026 and \$3.28
14 million associated with two other reasons — her claim that fuel handling
15 expenditures should ramp down before the plant fully converts to gas-fired
16 operations and her interest in protecting ratepayers from a cost that will not be
17 incurred outside of the projected test year.⁵

18

19 **Q12. What issue did you find with Witness Kindschy's recommendation to reduce**
20 **2026 Belle River fuel handling costs by \$2.19 million since the plant will not**
21 **operate on coal during the fourth quarter of 2026?**

22 A12. During review of Witness Kindschy's direct testimony and exhibits, I confirmed
23 that the Company already accounted for a partial 25% reduction in fuel handling
24 costs in its exhibits and proposed expense. However, this was not made clear in

⁵ Witness Kindschy DT, pages 9-11 and Exhibit S-15.2, lines 10 and 11.

Line
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1 discovery responses. As I will describe in further detail below, most of the \$2.19
2 million reduction Witness Kindschy recommends is already reflected in my Exhibit
3 A-13, Schedule C5.1, note 7 adjustment labelled BRPP Gas Conversion of Unit 1
4 and Witness Kindschy's additional reduction is, therefore, unnecessary and
5 duplicative.

6

7 **Q13. Can you further explain how the 25% reduction in Belle River fuel handling**
8 **costs is already reflected in your Exhibit A-13, Schedule C5.1, note 7**
9 **adjustment?**

10 A13. In order to forecast the 2026 O&M reduction that would result from converting
11 Belle River Power Plant from coal-fired to gas-fired operations, the Company took
12 the base plant spend (excluding only periodic outages) for 2023, escalated the
13 remaining expenses to 2026 dollars based on inflation, and assumed a 25%
14 reduction in expenses as shown in Witness Kindschy's Exhibit S-15.1 (shown
15 below in Figure 1).

16

17 **Figure 1 Calculation of 2026 O&M Reduction Associated with Belle**
18 **River Converting from Coal-Fired to Gas-Fired Operations**

Case No.: U-21860
Exhibit No.: S-15.1
Witness: Lisa M. Kindschy
Date: August 22, 2025
Page: 10 of 14

Case No.: U-21860
Request No.: STDE-4.9a
Respondent: M. Guillaumin
Page: 1 of 1

Michigan Public Service Commission
DTE Electric Company
Operation and Maintenance Expenses
Exhibit A-13 Sch. C5.1 Note 7 Adjustments -- BRPP Gas Conversion of Unit 1

	2023 Actual	Inflation			Inflation Adj	Inflation Adj (\$)	Remaining O&M	Gas reduction	Gas O&M
		2024	2025	2026	2026	2026	Post-U1 Conversion	Assumption for 2026	Reduction
Labor	21,842,672	3.40%	3.00%	3.10%	109.8%	\$ 23,984,032	75%	17,988,024	\$ (5,996,007.89)
Forced Outage	2,074,138	3.40%	3.00%	3.10%	109.8%	2,277,478	75%	1,708,108	(569,369)
Operations	2,559,366	3.40%	3.00%	3.10%	109.8%	2,810,275	75%	2,107,706	(702,569)
Maintenance	5,226,611	3.40%	3.00%	3.10%	109.8%	5,739,005	75%	4,304,254	(1,434,751)
Admin	380,960	3.40%	3.00%	3.10%	109.8%	418,308	75%	313,731	(104,577)
Performance	98,731	3.40%	3.00%	3.10%	109.8%	108,411	75%	81,308	(27,103)
Fuel	930,154	3.40%	3.00%	3.10%	109.8%	1,021,342	100%	1,021,342	-
Instrument	554,502	3.40%	3.00%	3.10%	109.8%	608,863	75%	456,647	(152,216)
Range	78,064	3.40%	3.00%	3.10%	109.8%	85,717	75%	64,288	(21,429)
	<u>\$ 33,745,199</u>					<u>\$ 37,053,430</u>		<u>\$ 28,045,408</u>	<u>\$ (9,008,022)</u>

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1 As shown in the figure above, all cost categories were reduced by 25% with the
 2 exception of \$930,154 related to “Fuel”, which represents fuel handling contract
 3 labor and materials. It should be noted that a portion of the Belle River fuel
 4 handling expense is included in the “Labor” line in the amount of \$7.8 million for
 5 2023 (\$7.8 million of the \$21.8 million labor line in 2023 was fuel handling), and
 6 this line was reduced by 25% in the Company’s calculations.

8 **Q14. What did Witness Kindschy use as a basis for her 25% reduction to Belle River**
 9 **fuel handling?**

10 A14. As shown in Witness Kindschy’s Exhibit S-15.2, page 2 (shown below in Figure
 11 2), Witness Kindschy’s calculation is based on Belle River Power Plant’s historical
 12 fuel handling costs from the DTE Electric annual report. On line 10 in the figure
 13 below, Witness Kindschy calculates a 25% reduction to line 1 (Belle River Power
 14 Plant Fuel Handling Costs).

16 **Figure 2 Witness Kindschy’s Belle River Fuel Handling Reduction Calculation**

DTE Electric Company Fuel Handling O&M Expenses Summary 2019 - 2024 MPSC Case No. U-21860 (\$900,000)							Case No.: U-21860 Exhibit No.: S-15.2 Witness: Lisa M. Kindschy Date: August 22, 2025 Page: 2 of 4		
MPSC Case No.: U-21860 Requestor: Staff Question No.: STDE-4.7 Respondent: M. Guillaumin							Staff's inflation rates 2025 2.9% 2026 3.4%		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
<u>Fuel Handling Costs</u>		Actual Jan-Dec 2019	Actual Jan-Dec 2020	Actual Jan-Dec 2021	Actual Jan-Dec 2022	Actual Jan-Dec 2023	Actual Jan-Dec 2024	Forecasted Jan-Dec 2025	Forecasted Jan-Dec 2026
1 Belle River Power Plant	\$	4.68	\$ 6.00	\$ 5.74	\$ 7.60	\$ 8.74	\$ 8.22	\$ 8.48	\$ 8.75
2 St. Clair Power Plant		7.59	4.11	4.67	2.65	-	-	-	-
3 Monroe Power Plant		2.61	4.17	3.12	8.04	2.41	6.72	6.91	7.15
4 River Rouge Power Plant		0.10	0.25	0.17	-	-	-	-	-
5 Trenton Channel Power Plant		0.73	0.19	0.26	0.12	-	-	-	-
6 MERC		11.20	11.52	9.73	9.17	8.09	9.15	9.42	9.74
7 Other - FS & Logistics		3.36	1.99	1.79	2.18	2.47	2.11	2.17	2.25
8 Blue Water Energy Center		-	-	-	0.26	1.59	0.01	0.01	0.01
9 Total Fuel Handling Reported Costs (\$91)	\$	30.27	\$ 28.83	\$ 25.48	\$ 30.92	\$ 23.30	\$ 26.21	\$ 26.97	\$ 27.89
¹ 2026 Fuel Handling forecast assumes 2023 actuals plus inflation and MNPP Fuel Supply Maintenance for Post MERC									
10						1/4 reduction for BR 2 entering outage last quarter of 2026 (= line 1 x 0.25)		\$	2.19
11						1/2 of remaining O&M in 2026 after removing 1/4 (= 0.5 x (line 1 - line 10))		\$	3.28
12						Staff's reduction to Belle River fueling handling O&M expenses in 2026 (lines 10 + 11)		\$	5.47

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1 Included in the Belle River Power Plant line for 2023 is the \$930,154 expense for
2 fuel handling contract labor and material and the remaining \$7.8 million fuel
3 handling expense discussed in the previous question and answer. In total, the fuel
4 handling contract labor, material, and DTE Electric labor add up to \$8.74 million
5 as shown in Figure 2 for Belle River Power Plant in 2023.⁶

6

7 **Q15. How did the Company respond to Staff discovery regarding Belle River fuel**
8 **handling O&M reductions?**

9 A15. The Company's responses provided in discovery and included in Witness
10 Kindschy's Exhibit S-15.2 indicate that no O&M fuel handling reductions would
11 occur beyond the projected test year. These future reductions would only occur
12 after both units are converted to natural gas. However, my response in the
13 referenced discovery did not properly reflect the reductions already assumed in the
14 test year. Specifically, my exhibits account for a \$1.95 million reduction⁷ in fuel
15 handling expense in Exhibit A-13, Schedule C5.1, note 7 adjustment labelled
16 'BRPP Gas Conversion of Unit 1'.

17

18 **Q16. Following Witness Kindschy's calculation, while also recognizing the**
19 **Company already accounted for a 25% reduction in DTE Electric fuel**
20 **handling labor in its exhibits, what would the remaining fuel handling**
21 **reduction amount to?**

⁶ While the Company utilized 2023 actual O&M expenses as the basis for its projection, Witness Kindschy utilized 2024 actual O&M as the basis for her projection in the figure above. Both years have a similar composition. 2024 Belle River fuel handling actual expense included "Labor" of \$7.3 million and "Fuel" of \$895,697.

⁷ The \$1.95 million reduction consists of \$7.8 million of 2023 fuel handling labor x 25% reduction.

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1 A16. The remaining fuel handling reduction would equal the fuel handling contract labor
2 and material that was not reduced (\$930,154) multiplied by 25%, or \$232,539 (in
3 2023 dollars).

4

5 **Q17. What do you conclude with respect to Witness Kindschy's proposed \$2.19**
6 **million reduction for Belle River fuel handling?**

7 A17. Witness Kindschy's proposed \$2.19 million adjustment related to Belle River fuel
8 handling appears to be overstated by roughly \$2 million. A 25% reduction was
9 applied to the \$7.8 million in the "Labor" line out of the total \$8.7 million actual
10 2023 Belle River fuel handling expenses. This was included in my previously filed
11 exhibits associated with my direct testimony.

12

13 **Q18. How do you respond to Witness Kindschy's recommendation to reduce Belle**
14 **River fuel handling by an additional \$3.28 million based on her belief fuel**
15 **handling expenditures should ramp down as the plant converts to gas-fired**
16 **operations?**

17 A18. Witness Kindschy's reasoning behind this portion of her recommendation is not
18 consistent with the coal handling operational requirements at the Belle River Power
19 Plant and should be rejected. The fuel handling costs Witness Kindschy is
20 recommending to reduce are primarily labor as discussed above. Her assumption
21 that these expenses will be cut by 25% and then ramp down by another 50% is
22 unsubstantiated and inconsistent with the way Belle River Power Plant operates.
23 The material, labor, and contractors that the Company employs to maintain this
24 system will all need to remain in place until Unit 2 ceases coal-burning operation.
25 Even after the full plant gas conversion, operations and maintenance will be needed

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1 to drain coal handling system fluids, isolate fuel supply utility services, and perform
2 final wash downs of fuel supply areas. Equipment-wise, almost the entirety of the
3 fuel supply system will need to remain operational to provide coal to Belle River
4 Unit 2. The fuel supply system feeding Belle River Power Plant utilizes a common
5 system of conveyor belts to bring coal into the plant before it is split and fed into
6 coal mills supplying the individual units. Reducing the number of coal-fired units
7 from two to one will not result in a 50% reduction in coal handling expenses.
8 Lastly, Witness Kindschy's generalization that, "... it is reasonable to expect the
9 Company to be ramping down spending on its Belle River fuel handling facilities
10 and to only spend O&M that is necessary to keep the facility operating until the
11 conversion of the entire plant to natural gas"⁸, does not account for the fact that all
12 equipment repairs in the final year of operation are expensed as O&M and are not
13 capitalized. Witness Kindschy's recommended \$3.28 million O&M reduction is
14 unlikely to materialize, as all fuel handling equipment must remain in service and
15 properly maintained until both units cease coal-fired operations.

16

17 **Q19. How do you respond to Witness Kindschy's recommendation to reduce Belle**
18 **River fuel handling by \$3.28 million based on protecting ratepayers from a**
19 **cost that will not be incurred outside of the projected test year?**

20 A19. Witness Kindschy's recommendation to allow recovery of only half of the expenses
21 she considers to be one-time and not extending beyond the projected test year is
22 discussed in the first section of my rebuttal testimony. This approach puts the
23 Company in a position to seek recovery of the remaining half of the 2026 expenses
24 in the next rate case (assuming it is filed promptly after the instant case) even

⁸ Witness Kindschy DT, page 10, lines 6-9.

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1 though those expenses would likely be incurred before or within the bridge period
2 rather than in the projected test year of a new case.

3

4 **Q20. What should the Commission find with respect to Witness Kindschy's \$5.47**
5 **million O&M reduction recommendation to Belle River fuel handling O&M?**

6 A20. The Commission should acknowledge that most of Witness Kindschy's
7 recommended \$2.19 million reduction is already included in the Company's
8 forecast, and the remaining \$3.28 million reduction recommendation should be
9 denied because it does not reflect the operational reality and required expenses of
10 coal handling at Belle River Power Plant. As I have explained above, reducing fuel
11 handling expense by 25% and then by 50% in 2026 for a plant that does not fully
12 cease coal-fired operations until the fourth quarter of 2026 is unreasonable and does
13 not reflect the necessary expenses to operate Belle River Power Plant.

14

15 Witness Kindschy's O&M Reduction to Steam Periodic Outage Normalization

16 **Q21. What does Witness Kindschy recommend with respect to the Company's**
17 **steam power periodic outage O&M normalization adjustment included in**
18 **Exhibit A-13, Schedule C5.1, Note 5?**

19 A21. Witness Kindschy recommends the steam periodic normalization be reduced by
20 \$4.4 million, from \$11.6 million requested to \$7.2 million.⁹

21

22 **Q22. What is the basis of Witness Kindschy's proposed \$4.4 million reduction to**
23 **steam periodic outage O&M normalization?**

⁹ Witness Kindschy DT, pages 11-14

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1 A22. Witness Kindschy cites three concerns Staff has with the Company's steam periodic
2 O&M normalization adjustment.

3
4 First, the historical years the Company used for normalization included actual
5 expenses from a time period when the Company still planned to operate the Monroe
6 Power Plant Units 3 and 4 beyond 2028.

7
8 Second, she claims that the Company's actual spending in previous years does not
9 support the level of forecasted periodic outage expenses in the projected test year
10 of this case.

11
12 Third, the periodic outage normalization adjustment presented in the instant case is
13 different from the calculation of the periodic outage normalization adjustment in
14 the prior case, Case No. U-21534.

15
16 **Q23. How do you respond to Witness Kindschy's first concern of including Monroe**
17 **Unit 3 and 4 periodic O&M in the historical normalization of 2023 O&M**
18 **expenses when the retirement of Monroe Units 3 and 4 is now projected to be**
19 **in 2028?**

20 A23. The major maintenance planned for 2026 is not related to Monroe Units 3 and 4.
21 In discovery response STDE-4.10 (Exhibit A-54, Schedule UU1), the Company
22 provided the forecasted major maintenance occurring in the projected test year. For
23 steam units, it shows the Belle River Unit 2 gas conversion outage and the Monroe
24 Unit 2 major periodic outage, totaling \$26.9 million (\$13.9 million plus \$13.0
25 million, respectively).

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1 It should be noted that in 2023 the Company only incurred \$9.8 million of periodic
2 outage expenses, mostly for major periodic maintenance on Monroe Unit 1. To
3 normalize the 2023 periodic outage expense, the Company, as shown on page 5 of
4 Witness Kindschy's Exhibit S-15.1, averaged the 2020-2022 actual periodic outage
5 expenses adjusted for CPI to 2023 values. The difference between 2023 actuals
6 and the 2020-2022 actuals adjusted for CPI was \$11.6 million. By adding the \$11.6
7 million to the 2023 historical test year, the Company included \$21.4 million (2023
8 dollars) in its request (\$9.8 million actual + \$11.6 million normalization). In terms
9 of 2026 dollars, this adjustment is equivalent to \$23.5 million (\$21.4 million
10 adjusted for the Company's 2024, 2025, and 2026 inflation rates of 3.4%, 3.0%,
11 and 3.1%, respectively, as shown in Exhibit A-13, Schedule C5.1). In short, the
12 Company's request in the instant case is already over \$3 million less than what it
13 anticipates to spend in 2026 (\$26.9 million forecast - \$23.5 million requested = \$3.4
14 million difference).

15
16 If Witness Kindschy's recommendation is adopted, it creates an additional shortfall
17 between the Company's planned work and approved funding in the instant case. In
18 recommending a \$4.4 million reduction to the Company's Steam periodic outage
19 adjustment, this recommendation in total provides only \$19.1 million for 2026
20 Steam periodic outages (\$23.5 million requested by the Company - \$4.4 million
21 reduction by Witness Kindschy). In other words, her proposed reduction creates a
22 nearly \$8 million gap between the Company's planned work on Belle River Unit 2
23 and Monroe Unit 2 and the funding being approved in the instant case. Additional
24 reduction in periodic outage spending will result in a reduced work scope, including
25 critical tasks such as boiler inspections and repairs that can only be performed

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1 during these large outages. Cutting these activities can negatively impact unit
2 reliability.

3

4 **Q24. How do you respond to Witness Kindschy's second concern that none of the**
5 **Company's actual spending in previous years supports the level of periodic**
6 **outage expenses in the projected test year?**

7 A24. As demonstrated above, the Company is not requesting all of the forecasted 2026
8 steam periodic O&M expenses in the instant case. The Company realizes that
9 periodic outage expenses vary from year-to-year and thus has utilized a multi-year
10 average of historical O&M expenses to normalize the 2023 expense.

11

12 **Q25. How do you respond to Witness Kindschy's third concern that the calculation**
13 **for the Company's 2023 periodic outage normalization in the instant case is**
14 **different from the calculation in U-21534?**

15 A25. I explained the difference in the periodic outage normalization calculations between
16 Case No U-21534 and the instant case in discovery response STDE-4.9c (Exhibit
17 A-54, Schedule UU2). As I explained then, the adjustment in the last case was
18 strictly based on moving the cost of a single major periodic outage (Belle River
19 Unit 2) from 2023 to 2024. It was not based on a multi-year historical average.
20 Rather, in the instant case, the calculation is based on a historical average adjusted
21 for CPI. On page 11, lines 18-19 of her direct testimony, Witness Kindschy does
22 not appear to disagree with this general approach.

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1 **Q26. What should the Commission find with respect to Witness Kindschy's**
2 **recommendation to reduce the steam periodic outage normalization**
3 **calculation by \$4.4 million?**

4 A26. The Commission should find Witness Kindschy's proposed steam periodic outage
5 normalization reduction leaves the Company underfunded for the Belle River Unit
6 2 and Monroe Unit 2 major periodic outages planned in 2026 to support ongoing
7 generation reliability. The Commission should deny Witness Kindschy's proposed
8 \$4.4 million O&M reduction.

9

10 **Part II – Rebuttal of Witness Coppola's Recommended O&M Reductions**

11 Witness Coppola's Reduction to Steam Power Generation O&M

12 **Q27. What does Witness Coppola recommend with respect to Steam Power**
13 **Generation O&M?**

14 A27. Witness Coppola recommends a \$25.5 million reduction to the Company's Steam
15 Power Generation O&M.¹⁰ He bases this reduction on his own forecast in which
16 he uses 2024 actual normalized expenses that are part of the bridge period in the
17 instant case and applies his own inflation rates while eliminating many of the
18 Company's adjustments.

19

20 In *his historical test period* (2024), he recommends the elimination of \$13.3 million
21 of the Company's normalization adjustments. These adjustments include the
22 economic reserve adjustment (\$2.4 million), the forced outage normalization (\$1.6
23 million), the periodic outage normalization (\$4.9 million), the excess and obsolete

¹⁰ Witness Coppola DT, page 121, lines 6-7.

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1 inventory adjustment (\$1.9 million), and the Sibley Quarry tipping fees credits for
2 BESS projects adjustment (\$2.5 million).

3

4 In the *projected test period* (2026), Witness Coppola eliminates \$11.0 million of
5 the Company's adjustments. These adjustments include the Monroe reliability
6 maintenance adjustment (\$7.7 million) and the Monroe fuel supply maintenance
7 for post-MERC (\$3.3 million).

8

9 In total, \$24.4 million of the \$25.5 million reduction Witness Coppola recommends
10 for Steam Power Generation is simply based on him inappropriately eliminating the
11 Company's adjustments, with the balance attributable to his lowering of inflation
12 rates.

13

14 *Witness Coppola's elimination of outage-related adjustments in Steam Power Generation*
15 *O&M*

16 **Q28. What reasoning did Witness Coppola provide for eliminating 100% of the**
17 **Company's 2024 historical normalizations associated with outages totaling**
18 **\$8.9 million, including normalizations for economic reserve shutdowns (\$2.4**
19 **million), forced outages (\$1.6 million), and periodic outages (\$4.9 million)?**

20 A28. Witness Coppola asserts it is "simply guess work" for the Company to propose that
21 2023 and 2024 were unusual years and that a similar level of activity will not occur
22 in 2026. Witness Coppola goes on to claim outages that occurred in 2021 and 2022
23 are not likely to occur at the same level in 2026.¹¹

24

¹¹ Witness Coppola DT, page 118, line 8 through page 119, line 2.

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1 **Q29. How do you respond to Witness Coppola's recommendation to remove 100%**
2 **of the historical normalizations associated with outages?**

3 A29. Witness Coppola's recommendation lacks justification and is not based on fact or
4 analysis. He claims the Company does not know which planned outages will occur
5 in 2026 or, if it knows, it has not disclosed those plans publicly.¹² He also asserts
6 without evidence that outages that occurred in 2021 and 2022 are not likely to occur
7 at the same level in 2026.

8

9 **Q30. Has the Company explained which Steam Power Generation planned outages**
10 **will occur in 2026?**

11 A30. Yes. In the instant case, on page 116 of my revised direct testimony, I explain the
12 Company will execute major periodic maintenance outages on Belle River Unit 2
13 and Monroe Unit 2, and minor periodic maintenance on Monroe Unit 3 in 2026.
14 Witness Coppola's statement that the 2026 planned outages have not been disclosed
15 is incorrect.

16

17 **Q31. How did the Company normalize outage expenses in the instant case?**

18 A31. For forced and planned outage expense normalizations, the Company took an
19 average of historical annual values adjusted for CPI to be comparable to 2023
20 dollars. The difference between 2023 actual expense and the average historical
21 expense adjusted for CPI was utilized for the Company's adjustment.

22

23 For the reserve shutdown normalization, the Company again compared the
24 historical test year 2023 actuals against prior year values. Reserve shutdown is a

¹² Witness Coppola DT, page 118, lines 14-16.

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1 period of time when a unit does not operate due to market conditions but is in a
2 stand-by status and required to operate if called upon. Expenses related to routine
3 operation including chemical usage, normal wear and tear, and labor resources are
4 reduced. In this instance, the comparison was made for reserve shutdown hours on
5 baseload units. Based on the difference in the level of reserve shutdown hours
6 between 2023 and prior years, the Company estimated the O&M impact as the
7 adjustment.

8

9 In short, the Company compared 2023 actuals against average historical data to
10 develop its reasonable adjustments in the instant case. Similarly, when asked to
11 provide 2024 expenses in discovery, the Company followed the same methodology,
12 utilizing 2024 as the base year.

13

14 **Q32. How do you respond to Witness Coppola's recommendation to not normalize**
15 **2024 for outages?**

16 A32. As discussed above, the normalization adjustments are required to bring the actual
17 expenses in line with historical averages. Due to higher reserve shutdowns and
18 lower forced and planned outage expenses, 2024 expense was reduced in
19 comparison to prior years. Basing O&M expenses on a year that was abnormally
20 low compared to history without making adjustments would be unreasonable.

21

22 **Q33. What should the Commission find with respect to Witness Coppola's**
23 **recommendation to eliminate \$8.9 million associated with outage**
24 **normalization adjustments?**

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1 A33. The Commission should deny Witness Coppola's recommendation to eliminate
2 100% of the requested outage normalization adjustments for Steam Power
3 Generation. The Company's normalization adjustments are reasonable and
4 required to bring actual expenses of the historical test year in line with average
5 historical levels.

6

7 *Witness Coppola's elimination of the Excess and Obsolete Inventory adjustment and Sibley*
8 *Quarry Tipping Fees for BESS Projects adjustment in Steam Power Generation O&M*

9 **Q34. What reasoning did Witness Coppola provide for eliminating the excess and**
10 **obsolete inventory adjustment and Sibley Quarry tipping fees for BESS**
11 **projects historical normalization adjustment for 2024?**

12 A34. Witness Coppola claims the Company did not explain or provide justification for
13 the excess and obsolete inventory adjustment and the Sibley Quarry tipping fees for
14 BESS projects adjustment.¹³

15

16 **Q35. How do you respond to Witness Coppola's recommendation to remove the**
17 **excess and obsolete inventory adjustment and Sibley tipping fees for BESS**
18 **projects adjustment from the 2024 historical normalization?**

19 A35. In the instant case, 2023 is the historical test year and is the starting point for the
20 basis of the Company's request. I explained the 2023 historical normalizations in
21 my revised direct testimony. Since that time, 2024 expenses have become
22 available, and Witness Coppola essentially attempts (by means of disregarding the
23 2023 detail provided by the Company and merely asserting 2024 expenses were

¹³ Witness Coppola DT, page 119, lines 3-4.

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1 “unsupported”) to change the historic test year – expecting the same level of detail
2 for a year that does not form the basis for the Company’s request in the instant case.

3

4 **Q36. What does the excess and obsolete inventory adjustment represent and why is**
5 **it appropriate?**

6 A36. The excess and obsolete inventory adjustment is an accounting entry made based
7 on the amount of inventory at a point in time and the age of the inventory. In any
8 particular year, the entry can be recorded as either a debit or credit as determined
9 by DTE Electric’s accounting policy. In the case of 2024, the inventory adjustment
10 entry was a credit that lowered O&M expenses by \$1.9 million. It is appropriate to
11 adjust O&M by removing the credit for the purposes of forecasting the projected
12 test year.

13

14 **Q37. What does the Sibley Quarry tipping fees credit for BESS projects adjustment**
15 **represent and why is it appropriate?**

16 A37. When the land at the Trenton Channel site was being prepared for BESS
17 installations, soil was excavated and transported to Sibley Quarry for disposal.
18 Material sent to Sibley Quarry is charged a disposal fee, which is recorded as a
19 credit to Sibley Quarry’s O&M. In 2024, this resulted in a \$2.5 million credit to
20 O&M associated with the disposal of material from BESS project expenses. Since
21 this is a significant one-time credit, it is appropriate to make an adjustment for the
22 projected test year to avoid understating O&M expenses.

23

24 **Q38. What should the Commission find with respect to Witness Coppola’s**
25 **recommendation to eliminate \$4.4 million associated with the Excess and**

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1 **Obsolete Inventory adjustment (\$1.9 million) and the Sibley Quarry Tipping**
2 **Fees for BESS Projects adjustment (\$2.5 million)?**

3 A38. The Commission should deny Witness Coppola's recommendation to eliminate the
4 Excess and Obsolete Inventory accounting credit and the Sibley Quarry Tipping
5 Fees credit for Steam Power Generation. The adjustments were one-time
6 reductions in 2024 O&M and were properly applied to normalize 2024 O&M
7 expenses.

8

9 *Witness Coppola's elimination of the Monroe Reliability Maintenance adjustment in Steam*
10 *Power Generation O&M*

11 **Q39. What is Witness Coppola's basis for removing 100% of the \$7.7 million for**
12 **Monroe Power Plant reliability maintenance O&M from the projected test**
13 **year?**

14 A39. Witness Coppola believes that the items provided in discovery fit into the category
15 of routine maintenance. Being routine maintenance expenses, Witness Coppola
16 feels that they should already be included in historical actuals and thus should be
17 removed as adjustments to reach the projected test year expense amount.¹⁴

18

19 **Q40. Does Witness Coppola provide specific support for removing 100% of the \$7.7**
20 **million planned for Monroe reliability maintenance O&M?**

21 A40. No. Witness Coppola provides insufficient reasoning and no specific evidence for
22 his removal of these increased maintenance activities from the 2026 projected test
23 year. He merely states that these are routine maintenance activities and should
24 already be included in 2024 historical O&M expense.

¹⁴ Witness Coppola DT, page 120, lines 1-5.

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1 **Q41. Has the Company provided specific support for the activities it will undertake**
2 **for the \$7.7 million Monroe reliability maintenance O&M?**

3 A41. Yes. In discovery response STDE-4.9a (Exhibit A-54, Schedule UU3), I provided
4 the five major equipment areas that will benefit from the increase in maintenance
5 expense. Those equipment areas are (1) sootblower preventative maintenance
6 inspections, (2) coal mill 4,000 operating hour (4K) inspections for each of the
7 seven coal mills on each unit, (3) replacement of polisher resin on Units 3 and 4
8 common water system, (4) induced draft (ID) fan blade restoration for each unit,
9 and (5) selected equipment cleanings. In the same discovery response, I also
10 provide descriptions of the work to be completed.

11

12 **Q42. Why are these maintenance activities necessary to be performed in the**
13 **projected test period at Monroe Power Plant?**

14 A42. The level of work completed on these equipment areas during 2023 and 2024
15 included work necessary to continue safe, environmentally compliant, and reliable
16 equipment operations, but was insufficient to fully support the Company's
17 recommended preventative maintenance plan. Executing these planned activities in
18 2026 will allow the Company to restore maintenance to a regular schedule and will
19 minimize incremental work required in the years following 2026.

20

21 **Q43. What should the Commission find with respect to Witness Coppola's**
22 **recommendation to eliminate 100% of the requested \$7.7 million adjustment**
23 **associated with Monroe reliability maintenance O&M?**

24 A43. The Commission should reject Witness Coppola's recommendation to remove \$7.7
25 million from the projected test year. Witness Coppola provides almost no reasoning

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1 as to why this should be removed from the projected test period aside from the fact
2 that it should have occurred in 2024. The Commission should find the Company is
3 reasonable in including these expenses to continue to ensure the safe and reliable
4 operation of Monroe Power Plant.

5

6 *Witness Coppola's elimination of the Monroe Fuel Supply Maintenance for Post MERC*
7 *adjustment in Steam Power Generation O&M*

8 **Q44. What is Witness Coppola's position regarding the Company's plan for**
9 **maintenance of Monroe Fuel Supply equipment?**

10 A44. Witness Coppola claims the Company's discovery responses related to the 2026
11 O&M expense "still leaves questions unanswered" and then proceeds to list his
12 lingering questions.¹⁵ Witness Coppola ultimately concludes that the Company did
13 not explain when Midwest Energy Resources Company (MERC) will close, how
14 the cost was developed, or why the overhaul needs to be done. Based on this,
15 Witness Coppola recommends removal of the entire \$3.3 million expense.

16

17 **Q45. When is MERC expected to end operations?**

18 A45. Please refer to my revised direct testimony, page 122, lines 7-9 as well as Company
19 Witness Milo's direct testimony, page 8, line 17. MERC is planned to close at the
20 end of June 2026.

21

22 **Q46. How do you respond to Witness Coppola's recommendation to eliminate \$3.3**
23 **million of funding that supports Monroe fuel supply maintenance?**

¹⁵ Witness Coppola DT, pages 120-121.

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1 A46. On page 122 of my revised direct testimony, I describe the need for the Monroe
2 fuel supply adjustment. I state, "After MERC closes in mid-2026, Monroe Power
3 Plant will no longer receive low sulfur western coal by vessel from MERC. Instead,
4 all western coal will come by rail. In order to maintain coal inventory at the plant,
5 high reliability of the rail car dumper and supporting equipment will be needed
6 year-round. Due to the increase in rail deliveries and associated coal tonnages,
7 additional maintenance will be needed on the rail car dumper equipment and other
8 fuel supply coal handling equipment and infrastructure." Witness Coppola's
9 recommendation to eliminate the Monroe fuel supply maintenance adjustment
10 seems to imply the unloading system can incur more wear and tear from higher
11 utilization without requiring additional maintenance, which is unreasonable.

12

13 **Q47. How does unloading coal by train differ from unloading by vessel?**

14 A47. Unloading coal by train requires the use of the plant's Train Unloading System
15 (TUS) equipment. The TUS includes the coal dumper house, railroad tracks and
16 conveyors, all of which are Monroe Power Plant assets and maintained by the plant.
17 When unloading coal by vessel, unloading equipment is contained on the vessel
18 and maintained by the vessel owner.

19

20 **Q48. What is the function of the TUS?**

21 A48. The Monroe Power Plant TUS unloads a coal unit train, a set of 130 railcars, by
22 clamping a 53-foot-long railcar fully-loaded with 120 tons of coal to the rails of the
23 track and rotating the individual railcars until the coal falls into a pit below the
24 rotating track. The empty railcar and the rotating rail tracks are returned to their
25 upright position, and the entire train is pulled ahead one railcar by a mechanical

Line
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1 arm in the dumper house. The same procedure is repeated 130 times to dump each
2 of the train railcars' contents. Once the coal is dumped from the railcars, the coal
3 is moved along over a mile of conveyors to a coal pile for storage and later use.

4

5 **Q49. What is the impact of unreliability on the TUS?**

6 A49. Monroe Power Plant receives approximately 7 million tons of coal annually. From
7 2021 to 2024, Monroe deliveries by vessel from MERC averaged nearly 1.6 million
8 tons of Low Sulfur Western Coal and Pet Coke. This accounts for over 20% of all
9 fuel received at Monroe Power Plant during that time. With the loss of the vessel
10 delivery option from MERC, all coal will now pass through the rail dumper system.
11 While Monroe does have the capacity to store a large amount of fuel on-site, the
12 plant's consumption rate requires continuous resupply of those stockpiles. Over
13 the last four years, Monroe has averaged approximately 320 train deliveries
14 annually. Unloading those trains in a timely manner is critical to the region's rail
15 system and the ability to maintain proper coal inventory for reliable plant operation.
16 The Company works closely with rail operators to schedule trains and optimize
17 logistics with all the other freight moving on our region's railways. Delays with
18 these operations could result in days and/or weeks when Monroe Power Plant does
19 not receive any coal deliveries by train, jeopardizing the ability to operate the plant.

20

21 **Q50. What scope of work is included in the Monroe Fuel Supply Maintenance**
22 **adjustment?**

23 A50. In discovery response STDE-4.9a (Exhibit A-54, Schedule UU3), the Company
24 explained planned maintenance of the coal dumper/dumper house at Monroe Power

Line
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1 Plant includes maintenance and replacement of components in the dumper,
2 positioner, track, and conveyors.

3

4 **Q51. What should the Commission find with respect to Witness Coppola's**
5 **recommendation to remove 100% of the Monroe Fuel Supply Maintenance for**
6 **Post-MERC adjustment?**

7 A51. The Commission should find the reliability of the Monroe TUS is critical to the fuel
8 delivery process at Monroe Power Plant. The requested funding is necessary to
9 maintain that reliability in light of increased utilization of the TUS after the closure
10 of MERC, and Witness Coppola's recommendation to eliminate the funding should
11 be denied.

12

13 **Q52. What should the Commission find with respect to Witness Coppola's**
14 **recommendation to reduce overall Steam Power Generation O&M by \$25.5**
15 **million?**

16 A52. The Commission should find the Company's normalizations and adjustments were
17 proper and dismiss all of Witness Coppola's recommendations. The Company
18 appropriately normalized economic reserve, forced and periodic outage expenses,
19 and properly included the excess and obsolete inventory adjustment and the Sibley
20 tipping fees for BESS projects adjustment. Additionally, the Monroe reliability and
21 Monroe fuel supply post-MERC adjustments are necessary to continue safe and
22 reliable operations. In summary, Witness Coppola's recommendations for across-
23 the-board 100% disallowance on every O&M topic he raised for Steam Power
24 Generation are unsupported.

Line
No.

1 Witness Coppola's Reduction to Other Power Generation O&M

2 **Q53. What does Witness Coppola recommend with respect to Other Power**
3 **Generation O&M?**

4 A53. Witness Coppola recommends a reduction of \$8.7 million to the Company's Other
5 Power Generation O&M. Similar to what I described in the Steam Power
6 Generation section above, he bases this reduction on his own forecast in which he
7 uses 2024 actual normalized expenses that are part of the bridge period in the instant
8 case and applies his own inflation rates while eliminating many of the Company's
9 adjustments.

10

11 In *his historical test period* (2024), he recommends the elimination of the
12 Company's \$0.4 million Blue Water Energy Center (BWEC) maintenance
13 normalization adjustment.

14

15 In the *projected test period* (2026), Witness Coppola eliminates \$8.1 million of the
16 Company's adjustments. These adjustments include the BWEC normalization of
17 periodic spend (\$3.6 million) and a portion of the peaker increased maintenance
18 adjustment (\$4.5 million).

19

20 In total, \$8.5 million of the \$8.7 million reduction Witness Coppola recommends
21 for Other Power Generation is simply based on him inappropriately eliminating the
22 Company's adjustments, with the balance attributable to his lowering of inflation
23 rates.

Line
No.

1 *BWEC Routine Maintenance Adjustment*

2 **Q54. What reasoning did Witness Coppola provide for eliminating the \$0.4 million**
3 **BWEC maintenance 2024 adjustment?**

4 A54. Witness Coppola asserts that after three years of operation, it is reasonable for the
5 level of routine maintenance performed during the warranty period to diminish
6 going into 2026. Therefore, he eliminated the Company's adjustment.¹⁶

7
8 **Q55. How do you respond to Witness Coppola's recommendation to remove the**
9 **BWEC maintenance 2024 normalization adjustment?**

10 A55. For the first two years of operation, equipment at BWEC was covered under
11 warranty. During this period, nearly all equipment repairs were addressed as
12 warranty claims and completed at the expense of the facility construction company.
13 Now that the warranty period has come to an end, I find it reasonable to assume a
14 slight increase in expenses as reflected in the Company's adjustment. This
15 adjustment is not tied to specific work on warranty claims or BWEC equipment.
16 Rather, it is simply recognizing that all equipment maintenance is now fully the
17 Company's responsibility.

18

19 **Q56. What should the Commission find with respect to Witness Coppola's**
20 **recommendation to eliminate the BWEC maintenance normalization**
21 **adjustment?**

22 A56. The Commission should find the Company's BWEC maintenance normalization
23 adjustment reasonable and reject Witness Coppola's recommendation to eliminate

¹⁶ Witness Coppola DT, page 122, lines 14-17.

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1 the adjustment. It is reasonable to assume a slight increase in expenses for
2 maintenance will be required when the equipment is no longer covered by warranty.

3

4 *BWEC Normalization of Periodic Outage Spend Adjustment*

5 **Q57. What reasoning did Witness Coppola provide for eliminating the \$3.6 million**
6 **BWEC Normalization of Periodic Outage Spend adjustment?**

7 A57. Witness Coppola asserts there could be cost savings that offset the periodic outage
8 costs when the plant is in a major periodic outage and not incurring normal
9 operation and maintenance expenses. Additionally, he indicates the Company has
10 had major periodic outages on its coal units in prior years and did not propose a
11 similar adjustment. Witness Coppola speculates that this is an indication that
12 incremental costs were offset by other cost savings.¹⁷

13

14 **Q58. How do you respond to Witness Coppola's recommendation to eliminate the**
15 **adjustment associated with the normalization of BWEC periodic outage**
16 **spend?**

17 A58. Contrary to Witness Coppola's assumption, O&M expenses actually increase
18 during periodic outages and do not stay flat. Case in point, the Company estimates
19 the 2026 BWEC routine scheduled major outage will cost over \$14 million in
20 O&M. BWEC's total annual O&M expense in 2023 was less than \$10 million as
21 shown in discovery response STDE-4.11 (Exhibit A-54, Schedule UU4). It is
22 unreasonable to conclude that a \$14 million periodic outage expense in 2026 can
23 be absorbed by \$10 million of annual non-periodic O&M funding. Furthermore,
24 major periodic outages are expected to occur once every four years at BWEC. This

¹⁷ Witness Coppola DT, page 123, lines 12-18.

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1 outage period is the time for equipment that would normally be online to be taken
2 offline, disassembled, inspected, and maintained. During this period, plant
3 personnel continue to support the needs of the plant with equipment tagging, testing
4 activities, inspections and maintenance work execution to keep equipment on the
5 unit reliable for another four years. As compared to reserve shutdown periods
6 during which cost savings are realized due to units being in stand-by without
7 maintenance activities occurring, plant personnel are extremely busy performing
8 work during periodic outages in excess of what is required during normal operation.

9

10 **Q59. How do you respond to Witness Coppola's comparison of BWEC to coal units**
11 **which he claims have not had a similar adjustment?**

12 A59. The Company has historically operated a fleet of coal-fired units and has leveled
13 major periodic outages so that they occur approximately every 3 to 4 years on
14 individual coal-fired units. While on an individual unit-basis the periodic outage
15 O&M spend is "lumpy", the periodic outage O&M spend at a multi-unit fleet level
16 is more consistent. Because of this consistency, the Company has not had to
17 regularly include a periodic outage O&M normalization in its rate cases in the past
18 for its coal-fired fleet and all of Steam Generation.

19

20 BWEC expenses, however, are included in Other Power Generation. BWEC is the
21 Company's only combined cycle power plant and has a planned major periodic
22 outage cycle on a four-year frequency based on unit run time and startups. Because
23 of these factors, BWEC spend is "lumpy" at both the individual unit basis and the
24 Other Power Generation level. As such, the Company levelizes the BWEC periodic
25 outage O&M spend in rate cases.

Line
No.

1 **Q60. What should the Commission find with respect to Witness Coppola's**
2 **recommendation to eliminate the BWEC Normalization of Periodic Outage**
3 **Spend adjustment?**

4 A60. The Commission should find the Company's normalization of BWEC periodic
5 outage O&M spend to be reasonable and deny Witness Coppola's recommendation
6 to eliminate the adjustment. Expenses reasonably increase during periodic outages
7 and do not stay flat.

8

9 *Peakers Increased Maintenance Adjustment*

10 **Q61. What justification does Witness Coppola provide for eliminating \$4.5 million**
11 **associated with the Peaker Increased Maintenance adjustment?**

12 A61. Witness Coppola asserts that to the extent peakers experienced higher maintenance
13 costs in 2024, the costs are already reflected in the calculation of 2026 O&M
14 expense. He also indicates peakers are dispatched during periods of high power
15 demand primarily driven by hot weather, which varies from year-to-year, and it is
16 guesswork to assume higher maintenance costs will occur in 2026.¹⁸

17

18 **Q62. How do you respond to Witness Coppola's recommendation to eliminate the**
19 **adjustment associated with increased peaker maintenance?**

20 A62. Similar to what is discussed above related to Witness Coppola's recommended
21 elimination of the Monroe Reliability Maintenance adjustment, Witness Coppola
22 ignores that work completed during 2024 was the bare necessities to maintain safe,
23 reliable operation. This barebones work scope did not include any work that would
24 offset the adjustments requested in 2026 in the instant case.

¹⁸ Witness Coppola DT, page 124, lines 6-12.

Line
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1 **Q63. How does a peaker's utilization relate to the O&M incurred on that unit in**
2 **that same year?**

3 A63. A peaker's utilization in an individual year is not an indication of the actual O&M
4 expense incurred. In other words, just because a peaking unit ran at a high capacity
5 factor during a year, that is not an indication that it also incurred high maintenance
6 costs. Rather, the wear and tear on the peaker's equipment builds up over time (i.e.
7 multiple years), resulting in the need for increased maintenance in the near future.
8 The Company's peaker maintenance adjustment in the instant case is to support the
9 need for these future maintenance activities.

10

11 **Q64. What should the Commission find with respect to Witness Coppola's**
12 **recommendation to eliminate the Peaker Increased Maintenance adjustment?**

13 A64. The Commission should find the Peaker Increased Maintenance adjustment is
14 reasonable and Witness Coppola's request to eliminate the adjustment should be
15 denied. The adjustment supports future continued safe and reliable operation of the
16 Company's peaker fleet.

17

18 **Q65. What should the Commission find with respect to Witness Coppola's overall**
19 **recommendation to eliminate \$8.7 million of Other Power Generation**
20 **Expenses?**

21 A65. The Commission should find the Company's adjustments were proper and dismiss
22 all of Witness Coppola's recommendations. The Company appropriately included
23 adjustments for BWECE routine maintenance, BWECE periodic outage spend, and
24 increased maintenance on peakers. These adjustments are necessary to continue
25 safe and reliable operations at BWECE and the Company's peakers.

Line
No.

1 **Part III – Rebuttal of Witness Coppola’s and Witness York’s Capital Disallowance**

2 **Recommendations**

3 **Witness Coppola’s Trenton Channel BESS Capital Disallowance**

4 **Q66. What does Witness Coppola recommend with respect to the Company’s**
5 **Trenton Channel BESS project (Exhibit A-12, Schedule B5.1, page 2, line 38)?**

6 A66. Witness Coppola recommends a reduction of \$64.7 million to the Company’s
7 Trenton Channel BESS forecast. His recommended reduction is comprised of two
8 parts: \$31.2 million related to a revised project forecast that is lower than the
9 Company requested in the instant case and \$33.5 million related to necessary
10 project contracts that have not yet been finalized.¹⁹

11

12 **Q67. How do you respond to Witness Coppola’s recommendation to reduce the**
13 **Trenton Channel BESS project by \$31.2 million; the amount of the reduction**
14 **associated with the Company’s updated forecast?**

15 A67. I find Witness Coppola’s recommendation reasonable. Staff Witness DeCooman
16 also discussed the updated project forecast on page 9 of his direct testimony and
17 requested the Company provide the revenue deficiency impact in rebuttal.
18 Company Witness Vangilder has performed this calculation and discusses it in his
19 rebuttal testimony.

20

21 **Q68. How do you respond to Witness Coppola’s recommendation to reduce the**
22 **Trenton Channel BESS project by \$33.5 million, the total amount of the**
23 **project contracts that are not yet finalized?**

¹⁹ Witness Coppola DT, pages 45-46.

Line
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1 A68. Witness Coppola's proposed disallowance related to contracts that are not yet
2 finalized is unreasonable. The work he recommends disallowing is required to
3 complete the BESS project. In discovery response STDE-13.1b²⁰, the Company
4 indicated the remaining work that has not yet been contracted includes the
5 continuation of engineering and construction services [REDACTED] continuation
6 of owners engineering services [REDACTED] and costs associated with test
7 energy for commissioning the project (0.51 million). Of the \$33.5 million Witness
8 Coppola proposes for disallowance, [REDACTED] is related to the continuation of
9 engineering and construction services. The Company is currently in active
10 discussions with the vendor for these services and has since refined the [REDACTED]
11 [REDACTED]
12 [REDACTED]

13
14 **Q69. What work is included in the [REDACTED] of work supporting the**
15 **continuation of engineering and construction services?**

16 A69. The work scope related to the [REDACTED] can be summarized by the three
17 activities listed below:

18
19 1) *Updated Design* [REDACTED] An improved, denser energy storage
20 configuration requires updates to the planned BESS layout and infrastructure.
21 This includes modifications of electrical cabling, electrical circuits, and civil
22 design.

²⁰ See Exhibit AG-9, page 3 of 4.

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1 2) *Field Modifications* [REDACTED] Based on site conditions, additional soil
2 excavation and remediation is required along with reconfiguration of the
3 drainage system and grounding grid modifications.

4
5 3) *Schedule Changes* [REDACTED] Switching equipment vendors has lowered
6 overall project costs but has pushed the active construction period for the
7 project into winter months. This requires adjustments to construction methods
8 to account for colder and wetter conditions.

9
10 **Q70. What should the Commission find with respect to Witness Coppola's**
11 **recommendation to reduce the Trenton Channel BESS forecast by \$64.7**
12 **million?**

13 A70. The Commission should find it is reasonable to reduce the project by [REDACTED]
14 based on the Company's updated project forecast²¹. However, the additional
15 reduction proposed by Witness Coppola to disallow all expenditures associated
16 with work still being contracted is unreasonable. The work is clearly necessary to
17 support the completion of the Trenton Channel Energy Center BESS project.

18
19 Witness Coppola's Routine Capital Disallowance of Five Specific Projects

20 **Q71. What does Witness Coppola recommend with respect to the Company's**
21 **forecasted 2026 routine power generation capital expenditures?**

²¹ The [REDACTED] includes the \$31.2 million reduction Witness Coppola and Witness DeCooman discussed in direct testimony, along with a [REDACTED]

Line
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1 A71. Witness Coppola recommends the removal of five power generation projects
2 totaling \$63.7 million in the Company's 2026 forecast.²² The projects are
3 summarized in the table below:

4
5 **Table 2 2026 Routine Power Generation Projects Witness Coppola**
6 **Recommends for Removal**

Project Name	Amount (\$ million)	Exhibit A-12, Schedule B5.1, Page 7, Reference Line
Monroe Unit 1 SCR Catalyst Layers 1, 2, and 4 (PMP 21297)	\$6.9	189
BWEC CTG11 Hot Gas Path Overhaul (PMP 19405)	\$22.9	211
BWEC CTG12 Hot Gas Path Overhaul (PMP 19406)	\$23.8	213
BWEC Steam Turbine Valves (PMP 20047)	\$6.3	219
Renaissance Unit 3 Peaker Combustion Overhaul (PMP 21272)	\$3.8	228
Total	\$63.7	

7

8 **Q72. What is the basis of Witness Coppola's proposed disallowance of five routine**
9 **projects in 2026?**

10 A72. Witness Coppola argues that the projects are forecasted by budget estimate. He
11 argues these budget estimates are very preliminary and in the early phase of
12 development with no project design yet completed.²³

13

14 **Q73. How do you respond to Witness Coppola's recommendation to reduce 2026**
15 **total capital expenditure by \$63.7 million, with full disallowance of projects in**
16 **the budget estimate phase of development?**

²² Witness Coppola DT, pages 51-52.

²³ Witness Coppola DT, page 52, lines 6-11.

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1 A73. Witness Coppola's recommendation for disallowance is unreasonable. In
2 discovery response AGDE-3.110a (Exhibit AG-12, pages 2-3), I was asked to
3 define the current phase of development for each project over \$3 million. In
4 response, I utilized Table 1 of my revised direct testimony (page 19) to define each
5 project. This is a high-level definition and does not completely specify what work
6 has been completed. The five projects Witness Coppola recommends for exclusion
7 have full internal approval, a defined scope (see Exhibit A-54, Schedule UU5 for
8 project workpapers), and cost estimates based on actual costs from similar projects
9 completed in the recent past or based on vendor proposals for the specific project.
10 Most have contracts that were negotiated, including the Renaissance Unit 3
11 Combustion Overhaul, the BWEC Hot Gas Pass Overhauls on CTG11 and CTG12,
12 and the BWEC Steam Turbine Valve Overhauls. Materials have been ordered
13 and/or are in stock for the BWEC hot gas path overhaul and steam turbine valve
14 projects. All five projects are progressing on schedule to meet the planned project
15 timelines.

16
17 The Monroe Unit 1 SCR Catalyst project is a routine environmental project similar
18 to what has been completed on all four Monroe units for the past decade. Catalyst
19 replacements occur annually at the plant during periodic outages. The purpose of
20 these replacements is to meet the environmental air permit requirements to maintain
21 an acceptable level of NOx reduction.

22
23 The BWEC Hot Gas Path Overhauls are first-time projects for the BWEC units but
24 are comparable to peaker hot gas path overhauls the Company has performed in the
25 past. The existing long-term service agreement with the OEM specifies when the

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1 overhauls should occur and has a clearly defined overhaul scope. The project cost
2 is predominately costs already established in the long-term service agreement for
3 contract labor and materials provided by the OEM. Minor additional costs include
4 DTE Electric labor, support services, and indirect charges.
5

6

7 BWEC Steam Turbine Valve Overhauls is a first-time safety project for BWEC.
8 This project involves disassembly, inspection, repair, and reassembly of the valves.
9 The Company has experience performing similar valve overhauls at all other power
10 plants over many decades during periodic outages. The Company is well-versed in
11 the scope of work and the effort and costs of turbine valve overhauls.

12

13 Renaissance 3 Combustion Overhaul is a routine peaker project. Renaissance
14 combustion components are inspected and replaced during combustion overhauls,
15 hot gas path overhauls, and major overhauls. Since 2016, the Company has
16 performed more than ten combustion inspections and component replacements. In
17 2024, the Company negotiated pricing for the upcoming Renaissance combustion
18 overhauls required on all four units over the next several years. Renaissance Units
19 2 and 4 completed combustion overhauls in 2025.

20

21 **Q74. What should the Commission find with respect to Witness Coppola's**
22 **recommendation to reduce 2026 Power Generation routine capital**
23 **expenditures by \$63.7 million?**

24 A74. The Commission should deny Witness Coppola's recommendation to reduce Power
25 Generation routine capital by \$63.7 million. The Company has full internal
26 approval for each project, engineering and proposal solicitation has progressed,

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1 many contracts have already been awarded, and materials for the BWEC projects
2 have been ordered and placed in DTE Electric stock.

3

4 Witness Coppola's BWEC Final Payment Capital Disallowance

5 **Q75. What does Witness Coppola recommend with respect to the Company's final**
6 **payment to Kiewit for the construction of the Blue Water Energy Center?**

7 A75. Witness Coppola recommends the Commission disallow recovery of 100% of the
8 \$6 million final payment to Kiewit included in the Company's 2025 forecast capital
9 expenditures (Exhibit A-12, Schedule B5.1, page 2, line 32). Additionally, Witness
10 Coppola recommends that the Commission direct the Company to document and
11 justify capital expenditures at Blue Water Energy Center in the next rate case.²⁴

12

13 **Q76. What is the basis for Witness Coppola's recommendation to disallow recovery**
14 **of the final \$6 million payment?**

15 A76. Witness Coppola maintains that the Company is not holding Kiewit responsible for
16 what he regards as quality issues related to the construction of Blue Water Energy
17 Center.²⁵

18

19 **Q77. How do you respond to Witness Coppola's recommendation to disallow**
20 **recovery of the \$6 million payment?**

21 A77. The final payment is contractually required to complete the project. The plant
22 achieved commercial operation and has generated more than 26,000 GWh since
23 June 2022. Punchlist item resolution and certain equipment modifications to
24 optimize performance and reliability, which are the final steps associated with

²⁴ Witness Coppola DT, page 51, lines 1-5.

²⁵ Witness Coppola DT, page 50, lines 13-17.

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1 contractual project completion, are completely consistent with ordinary
2 commercial experience.

3

4 **Q78. How do you respond to Witness Coppola's recommendations that all large**
5 **capital expenditures at BWEC be fully documented and justified in the next**
6 **rate case?**

7 A78. The Company provides the same information related to large capital expenditures
8 at BWEC as it does for those at all of its power plants and generating facilities.
9 This includes direct testimony describing capital projects greater than \$1 million,
10 exhibits that include the projected expenditures, and workpapers containing the
11 latest project approval forms, justifications, scopes, and schedules. The actions that
12 Witness Coppola is recommending are already being executed by the Company.

13

14 **Q79. What should the Commission find with respect to Witness Coppola's**
15 **recommendation to disallow the BWEC final payment?**

16 A79. The Commission should reject Witness Coppola's recommendation to disallow the
17 final payment for the construction of BWEC. BWEC is fully operational and was
18 commissioned consistent with ordinary commercial experience and the final
19 payment is appropriate. The total cost for the construction of BWEC is below the
20 \$951.8 million approved by the Commission in the April 27, 2018, Order in Case
21 No. U-18419. Additionally, the Commission should find the Company has
22 provided sufficient evidence supporting its actual and projected capital
23 expenditures.

Line
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1 Witness Coppola's Slocum BESS Capital Disallowance

2 **Q80. What does Witness Coppola recommend with respect to the Company's**
3 **Slocum BESS project?**

4 A80. Witness Coppola recommends a \$5.0 million disallowance on the Slocum BESS
5 project.²⁶

6

7 **Q81. What is the basis of Witness Coppola's proposed partial disallowance of the**
8 **Slocum BESS project?**

9 A81. Witness Coppola points to the actual Slocum BESS project costs coming in \$10
10 million higher than the initial cost estimate of \$34.7 million and recommends 50%
11 of the cost increase be disallowed because the Company did not disclose costs were
12 escalating significantly or demonstrate it was taking corrective action.
13 Additionally, he states the Company never performed a cost/benefit analysis.²⁷

14

15 **Q82. How do you respond to Witness Coppola's claim that the Company did not**
16 **disclose costs were escalating on the Slocum BESS project or demonstrate it**
17 **was taking corrective action?**

18 A82. Witness Coppola appears to have overlooked prior case history. In the Company's
19 2024 Rate Case, Case No. U-21534, I explained on page 49 of my direct testimony,
20 "The Slocum Battery Pilot project costs are projected to be \$44.7 million. That
21 amount has increased from prior projections primarily due to increases in lithium
22 costs and actual construction bids received." I also provided additional information
23 during discovery related to project cost increases discussed in that case, some of
24 which Staff included as Exhibit S-10.3 in Case No. U-21534. In the Case No. U-

²⁶ Witness Coppola DT, page 49, lines 7-9.

²⁷ Witness Coppola DT, pages 48-49.

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1 21534 Final Order dated January 23, 2025, the Commission approved the full
2 project costs except for \$2 million related to uncertainty in overheads on the project
3 as explained in discovery response AGDE-3.93c in the instant case (Exhibit A-54,
4 Schedule UU6).

5

6 **Q83. How do you respond to Witness Coppola's claim that the Company never**
7 **performed a cost/benefit analysis?**

8 A83. Cost/benefit analysis has also been discussed in prior cases. In Case No. U-20836,
9 Staff found, "Based on the evidence provided by the Company, Staff finds this pilot
10 would provide a value to the ratepayers in multiple ways. As identified by the
11 Company in Exhibit S-10.12, the BESS is expected to produce approximately
12 20,000 MWh annually, or a 17% capacity factor. This compares favorably to the
13 current Slocum diesel peaking units, which in recent years have had very limited
14 dispatch and energy production. The value provided by this dispatch is captured in
15 the estimated savings detailed by Company witness Morren. When factoring in the
16 anticipated significant maintenance of the current diesel-fired peaking units, as well
17 as the reduction in emissions and environmental impact to local communities the
18 retirement of these units will have, there are clear customer benefits. Operation of
19 this pilot also provides the Company with experience operating a BESS, with the
20 potential for this technology to replace other peaking units in the Company's fleet
21 in the future."²⁸ Subsequently, in Case No. U-21297, in the Final Order dated
22 December 1, 2023, the Commission was not persuaded by the AG's request for full
23 disallowance based on an insufficient cost benefit analysis.²⁹

²⁸ Witness DeCooman U-20836 DT, page 30, lines 3-14

²⁹ U-21297 Final Order dated December 1, 2023, page 245.

Line
No.

1 **Q84. What should the Commission find with respect to Witness Coppola's**
2 **recommendation to disallow \$5.0 million associated with the Slocum BESS**
3 **project?**

4 A84. The Commission should find Witness Coppola's recommendation fails to consider
5 information presented and decided in previous rate cases. The Company did
6 disclose the reasons for cost increases on the Slocum BESS and the project has been
7 valuable in helping the Company, contractors, and local municipalities understand
8 and manage the planned larger-scale upcoming BESS projects.

9

10 Witness Coppola's Monroe Fly Ash Basin Closure (CCR) Capital Disallowance and
11 Witness Coppola's and Witness York's Trenton Channel Seawall Capital Disallowance

12 **Q85. What is the basis of AG Witness Coppola's recommending a 50% disallowance**
13 **of capital related to the Monroe Fly Ash Basin Closure (CCR) (Exhibit A-12,**
14 **Schedule B5.1, page 2, line 46) and Witness Coppola and ABATE Witness**
15 **York's recommending full disallowance of the Trenton Channel Seawall**
16 **project (Exhibit A-12, Schedule B5.1, page 2, line 25)?**

17 A85. For the Monroe Fly Ash Basin Closure (CCR) project, Witness Coppola contends
18 that a 50% reduction (\$53.88 million) in regulatory asset costs is appropriate
19 because the project's implementation plan is still in development, a final contractor
20 has not been selected to complete the closure of the basin, and the Company's
21 Board of Directors has not yet fully approved the project.³⁰ Similarly, for the
22 Trenton Channel Seawall project, Witness Coppola and Witness York recommend
23 full exclusion of the \$9.456 million included in the projected test year at this time

³⁰ Witness Coppola DT, page 44, line 5 through page 45, line 2.

Line
No.

1 because the Company is in the process of designing the greenway path and that full
2 internal approval has yet to be obtained.³¹

3

4 **Q86. What is prompting the Company to complete the Monroe Fly Ash Basin**
5 **Closure (CCR) project?**

6 A86. This project is required for the Monroe Power Plant site to comply with federal and
7 state environmental regulations. As discussed on pages 36-38 of my revised direct
8 testimony, the existing Monroe Power Plant fly ash basin will be closed in place
9 and will require significant dewatering, grading, and capping efforts to meet
10 regulatory requirements.

11

12 **Q87. How do you respond to Witness Coppola's recommendation that the Company**
13 **exclude half of its proposed investment included in Exhibit A-12, Schedule**
14 **B5.1 for the Monroe Fly Ash Basin Closure (CCR) project?**

15 A87. While the Company appreciates AG Witness Coppola's proposed compromise to
16 include half of the projected capital expenditure in 2026, the scale of work required
17 to meet regulatory requirements necessitates the full investment be included in 2026
18 and there is little doubt that the project must be completed. Company Witness Lee
19 further demonstrates the regulatory necessity of the project as well as the required
20 closure time frames in his direct testimony.³²

21

22 **Q88. What should the Commission find with respect to AG Witness Coppola's**
23 **recommendation to exclude \$53.88 million from the regulatory asset account**
24 **for the Monroe Fly Ash Basin Closure (CCR) Project?**

³¹ Witness Coppola DT, page 47, lines 12-18 and Witness York DT, page 19, line 8 through page 20, line 8.

³² Company Witness Lee DT, page 20, line 4 through page 21, line 2.

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No.

1 **A88.** Witness Coppola’s recommendation to exclude amounts associated with this
2 Monroe environmental project should be disregarded. Management has approved
3 funds to proceed with the work as scheduled, additional formal funding approvals
4 will be gained in the ordinary course to complete the required environmental rule-
5 based work as the implementation plan is finalized, and contractors will be selected
6 to perform the work.

7

8 **Q89. What is prompting the Company to complete the Trenton Channel Seawall**
9 **project?**

10 A89. This project is required to restore the seawall’s integrity at the Trenton Channel
11 Power Plant site. The existing infrastructure is at its end of life and must be
12 replaced to ensure the stability of the land surrounding the riverfront. Additionally,
13 the City of Trenton stipulated the Company develop a pedestrian greenway path
14 that provides access to the Detroit River riverfront as part of the approved
15 demolition permit for the Trenton Channel Power Plant. Trenton Channel Power
16 Plant has been demolished and is currently being utilized as the site of the new
17 Trenton Channel BESS.

18

19 **Q90. How is the Trenton Channel Seawall Project progressing?**

20 A90. The Company has spent \$0.9 million to support engineering and design work. Full
21 project completion is currently scheduled for 2027.

22

23 **Q91. How do you respond to Witness Coppola statement that the project has not yet**
24 **received internal approval and is premature to include in rate base³³?**

³³ Witness Coppola DT, page 47, lines 12-18.

Line
No.

1 A91. The Company provided a signed appropriation request for \$1.1 million for the
2 Trenton Channel Seawall project that covers engineering and design of the future
3 site. The project is progressing as planned and there is no reason to expect the
4 Trenton Channel Seawall project will not be completed.

5

6 **Q92. How do you respond to Witness York's statement that the Company has not**
7 **demonstrated that it will make the proposed investments included in Exhibit**
8 **A-12, Schedule B5.1³⁴?**

9 A92. Witness York's Exhibit AB-8, page 1 shows a signed appropriation request for \$1.1
10 million for the Trenton Channel Seawall project. This funding supports the design
11 and engineering of the project components. Spend through May 2025 totals \$0.9
12 million, approaching the appropriated amount for design and engineering. An
13 appropriation request that includes the full project budget will be executed once the
14 design and engineering are complete.

15

16 **Q93. What should the Commission find with respect to AG Witness Coppola and**
17 **ABATE Witness York's proposed exclusion of the Trenton Channel Seawall**
18 **project?**

19 A93. The Commission should reject both Witness Coppola's and Witness York's
20 recommendations to exclude funding for the Trenton Channel Seawall project in
21 the instant case. The project is required to restore sections of the seawall to safe
22 condition for pedestrian use. The project is also a component of the permit with
23 the City of Trenton and must be completed to meet the requirements for
24 decommissioning Trenton Channel Power Plant.

³⁴ Witness York DT, page 20, lines 3-6.

Line
No.

1 **Q94. Does this conclude your rebuttal testimony?**

2 A94. 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

REBUTTAL TESTIMONY

OF

DAVID C. MILO

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF DAVID C. MILO

Line
No.

1 **Q1. Please state your full name, business address and by whom you are employed.**

2 A1. My name is David C. Milo and my business address is One Energy Plaza, Detroit,
3 Michigan 48226. I am employed by DTE Electric Company.

4

5 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
6 **Company (DTE Electric or Company)?**

7 A2. Yes.

8

9 **Purpose of Testimony**

10 **Q3. What is the purpose of your rebuttal testimony?**

11 A3. The purpose of my rebuttal testimony is to rebut the position of Witness Jester who
12 provided direct testimony on behalf of Michigan Environmental Council (MEC),
13 Natural Resource Defense Council (NRDC), and Citizens Utility Board of
14 Michigan (CUB) (collectively MNC). Specifically, my rebuttal will address
15 Witness Jesters recommendation that \$1.7 million of Midwest Energy Resources
16 Company (MERC) Fuel Handling O&M expenses be disallowed.¹

17

18 **Q4. Are you sponsoring any exhibits in this proceeding?**

19 A4. No.

20

21 **Q5. What basis does MNC Witness Jester use to recommend the disallowance?**

22 A5. Witness Jester bases his recommended disallowance on two reasons: the
23 inappropriate application of inflation adjustment to a declining cost, and the
24 Company's historical underspending on MERC's Fuel Handling O&M. Regarding

¹ Witness Jester Direct Testimony, DBJ-26, 7:8

Line
No.

1 his first reason, Witness Jester indicates on page 24, lines 15-18 of his testimony,
2 that “an inflation escalator is intended to preserve purchasing power for a constant
3 level of service”, consequently, since “DTEE is not projecting to provide the same
4 level of service over the [test year] period, ...any inflation adjustments are
5 inappropriate.”

6

7 **Q6. What is the Company’s response to MNC Witness Jester’s first reason that the**
8 **application of an inflation factor is not appropriate to project expense**
9 **amount?**

10 A6. The use of an inflation factor does not mean the final projected cost is not
11 reasonable when other adjustments are also made to derive the projected cost.
12 Witness Jester ignores the fact that there are fixed O&M expenses that are
13 associated with the operation of an industrial transshipment facility that are incurred
14 even at low volumes, and it is reasonable to apply an inflation factor to adjust those
15 costs. DTE Electric uses an inflation factor as a standard, companywide O&M
16 forecast development tool in its O&M Exhibits. I then adjusted MERC’s O&M
17 inflated amount to what the Company estimated to spend in the projected test
18 period. This adjustment named “Other Adjustment,” in effect, removes the inflation
19 adjustments of \$329 thousand and includes another reduction of about \$1.7 million
20 of spending. Witness Jester disregards my testimony that the projected expenses
21 after Other Adjustment “represents the minimum expenses required to operate the
22 facility”.² Once the Other Adjustment is applied, the calculation results in the total
23 projected O&M expense of \$1.7 million, based on a bottom-up forecast of expenses
24 for the MERC facilities’ remaining six months of operation and is a reduction of

² Witness Milo Direct Testimony, DCM-16, 22:25.

Line
No.

1 over 50% from the historical 2023 total expense. His assertion that the mere use of
2 inflation factors in this case is not reasonable for projecting spending is used to
3 justify his claim for complete disallowance of O&M expenses at MERC, disregards
4 reasonable adjustments and real O&M expenses. The Company's methodology to
5 apply inflation adjustment factor, and factor in Other Adjustments to equalize to a
6 bottom-up expense projection is a reasonable and prudent approach.

7

8 **Q7. Can you elaborate on Witness Jester's second reason justifying his**
9 **disallowance recommendation?**

10 A7. Yes. Witness Jester argues that the Other Adjustment amount reflects the scheduled
11 closure of MERC's transshipment business in June 2026, but it does not reflect
12 adjustments for historical underspending.³ Therefore, he further concludes that
13 since DTE Electric "has already recovered sufficient amounts in prior years",
14 resulting from 'historical underspending', then the projected spending requested in
15 this proceeding should be disallowed.⁴

16

17 **Q8. What is the Company's response to the assertion that the Other Adjustment**
18 **should have included an "underspending" component?**

19 A8. Witness Jester's recommendation to eliminate all projected O&M test year
20 spending at MERC, based on historical actuals, does not seek to accurately estimate
21 the correct 2026 projected test year O&M expense for MERC. Instead, it appears
22 intended to penalize the Company for its past projections. It is not reasonable to
23 disallow 100% of the 2026 projected cost today in response to a cumulative 11%

³ Witness Jester Direct Testimony, DBJ-26, 3:4

⁴ Witness Jester Direct Testimony, DBJ-26, 8:9

Line
No.

1 over estimation in the Company's prior three general rate cases.⁵ Witness Jester's
2 proposed new method does not seek to prospectively establish the correct rates to
3 recover MERC O&M expense but rather seeks to recover what Witness Jester
4 considers past overcollections by eliminating all O&M for operating a fuel
5 transshipment facility. This position is not reasonable.

6

7 **Q9. Did the Company address the issue of O&M spending in Witness Uzenski's**
8 **and Witness Milo's direct testimony?**

9 A9. Yes. Witness Uzenski addressed this issue in Q194 of her revised direct testimony
10 stating, "The Company proposes deferring as a regulatory liability any O&M costs
11 at MERC that continue to be recovered in rates above the actual amount incurred,
12 until rates are reset in a future rate case"⁶, which I referred to in my direct
13 testimony, DCM-17 lines 1-4.

14

15 **Q10. What is your recommendation with respect to Witness Jester's proposal to**
16 **disallow \$1.7 million in O&M MERC fuel handling O&M?**

17 A10. The Commission should find that the Company submitted a reasonable projection
18 of MERC O&M expenses necessary to continue providing coal for the Belle River
19 and Monroe Power Plants during the test year. The Commission should reject
20 Witness Jester's claims that DTE Electric inappropriately applied an inflation
21 adjustment to a declining cost, and that the Company should adjust the projected
22 O&M expenses because of alleged historical underspending in prior years. DTE
23 Electric was proactive and requested special accounting treatment so that MERC
24 O&M spending under amount recovered in rates would be treated as a regulatory

⁵ Witness Jester Direct Testimony, Exhibit CUB-18

⁶ Witness Uzenski's Revised Direct Testimony, TMU-98 7:12

Line
No.

1 liability. The Commission should find that Witness Jester's assertion - that the
2 Company should adjust for missed prior forecasts- is not appropriate in the context
3 of general rate case proceedings. Therefore, the Commission should not disallow
4 the \$1.7 million of MERC O&M projected expenses for the test year.

5

6 **Q11. Does this conclude your rebuttal testimony?**

7 A11. 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)
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for miscellaneous accounting authority.)

Case No. U-21860

REBUTTAL TESTIMONY

OF

SHAWN D. BURGDORF

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF SHAWN D. BURGDORF

Line
No.

1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed?**

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

7

8 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
9 **Company (DTE Electric or the Company)?**

10 A2. Yes.

11

12 **Purpose of Testimony**

13 **Q3. What is the purpose of your rebuttal testimony?**

14 A3. The purpose of my testimony is as follows:

15 **Section I: State Reliability Mechanism (SRM) Capacity Charge**

16 To address Energy Michigan Witness Zakem's discussion of variable costs from
17 Power Purchase Agreements (PPA) costs being included in the "Fuel Costs" for the
18 "energy revenue sales net of fuel cost calculation" beginning on page 19, line 21
19 and ending on page 22, line 12 of his testimony.

20

21 **Section II: Resetting PSCR base rates**

22 To address MPSC Staff Witness Revere's recommendation to reset the PSCR base
23 amount in main rates. I will explain the significant amount of additional effort it
24 would take the Company and other intervenors to facilitate updating the PSCR base.

25

Line
No.

1 **Q4. Are you sponsoring any exhibits in this proceeding?**

2 A4. No.

3

4 **Section I: State Reliability Mechanism (SRM) Capacity Charge**

5 **Q5. Do you agree with Energy Michigan Witness Zakem's discussion that**
6 **inconsistencies between utilities for the treatment of costs associated with**
7 **power purchase agreements (PPAs) have any meaningful impact on the SRM**
8 **capacity charge?**

9 A5. No. As Witness Zakem acknowledged in his direct testimony page 19, line 23
10 through page 20, line 1, the issue of whether to include a variable component of
11 PPAs as an offset to energy sales revenue was approved in Case No. U-21534. DTE
12 Electric showed in that case how it does not matter whether a portion of the PPA is
13 considered variable or not. If the variable amount from PPAs is not an offset to the
14 energy sales revenues, then those costs would be considered capacity-related and
15 result in the exact same SRM charge. Thus, it does not matter if those costs are
16 categorized differently by other utilities as it should not impact the SRM charge.

17

18 **Section II: Resetting PSCR base rates**

19 **Q6. Do you believe it would be reasonable in DTE Electric's next case to update**
20 **the PSCR base in main rates as recommended by MPSC Staff Witness Revere**
21 **(page 6, lines 5-6 of direct testimony)?**

22 A6. No. I understand Staff Witness Revere's rational, however, the amount of time and
23 effort required to update the PSCR base amount would be similar to repeating the
24 work required for a PSCR case. This would require additional witnesses,
25 particularly from the Company's Generation Optimization, Corporate Fuel Supply,

Line
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1 Controller's and Regulatory Affairs groups, who would have to perform additional
2 work (assumption gathering, modeling, testimony, exhibits, etc.) to create new
3 testimony and exhibits for both the historical test year and future test year. These
4 witnesses as well as intervenors would have the additional work throughout the rate
5 case process that is essentially a repeat of the same type of data/information that is
6 already litigated through the PSCR Plan and PSCR Reconciliation cases every year.
7 In addition to the unnecessary overlapping work for the Company and intervenors,
8 it could introduce the distinct possibility of confusion between assumptions made
9 in the rate case and PSCR Plan case for items such as sales forecast and forecasted
10 fuel and purchased power costs.

11

12 Company Witness Willis provides testimony regarding the role of the PSCR and
13 cost allocation.

14

15 **Q7. Does this conclude your rebuttal testimony?**

16 A7. Yes it does.

STATE OF MICHIGAN
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Case No. U-21860

REBUTTAL TESTIMONY

OF

JEFFREY C. DAVIS

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF JEFFREY C. DAVIS

Line
No.

1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed?**

3 A1. My name is Jeffrey C. Davis. My business address is: 6400 North Dixie Highway,
4 Newport, Michigan, 48166. I am employed by DTE Electric Company at the Fermi
5 2 Nuclear Power Plant as Expert - Nuclear Strategic Business Operations.

6
7 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
8 **Company (DTE Electric or Company)?**

9 A2. Yes.
10

11 **Purpose of Testimony**

12 **Q3. What is the purpose of your rebuttal testimony?**

13 A3. The purpose of my rebuttal testimony is to rebut the positions of Witness Coppola
14 who provided direct testimony on behalf of the Michigan Attorney General (AG).
15 Specifically, my rebuttal will address Witness Coppola's proposed disallowances
16 of Nuclear Generation capital expenditures and O&M expenses.

17
18 **Q4. Are you sponsoring any exhibits in this proceeding?**

19 A4. Yes. I am sponsoring the following exhibits:

<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
A-47	MM1	Nuclear Production Plant

22
23 **Q5. Were these exhibits prepared by you or under your direction?**

24 A5. Yes, they were.

Line
No.

1 **NUCLEAR GENERATION CAPITAL EXPENDITURES**

2 **Q6. Why are you rebutting the direct testimony of Witness Coppola relative to the**
3 **Nuclear Generation capital expenditures and O&M expenses?**

4 A6. The Nuclear Generation disallowances proposed by Witness Coppola represent an
5 imprudent and unreasonable reduction of approximately \$77.7 million in Nuclear
6 Generation's projected project capital expenditures and approximately \$5.8 million
7 in Nuclear Generations operating expenses.

8

9 Nuclear Generation's projected project capital expenditures for the 24-month-
10 period-ending December 31, 2026, in total, are approximately \$265.4 million so
11 Witness Coppola's proposals would eliminate nearly 30% of the Company's
12 projected capital expenditures for two years at the Fermi 2 Power Plant (Fermi 2).
13 The Company's proposed expenditures are consistent, both operationally and
14 economically, with historical capital deployment at Fermi 2.

15

16 Additionally, Witness Coppola proposed a reduction of approximately \$5.8 million
17 of nuclear operating expenses against DTE Electric's projected test-period
18 expenses for the 12-month-period-ending December 31, 2026, of approximately
19 \$160.0 million.

20

21 Witness Coppola's proposed disallowances were reached by applying a series of
22 inappropriate conclusions which I will individually rebut later in my testimony.

Line
No.

1 **ATTORNEY GENERAL PROPOSALS**

2 **Q7. What are your thoughts concerning Witness Coppola's proposed reductions**
3 **of approximately \$77.7 million of Nuclear Generation capital from rate base?**

4 A7. The proposed removal of approximately \$77.7 million of Nuclear Generation
5 capital expenditures would not be reasonable and would not be prudent.

6

7 Nuclear Generation projects support the safe and reliable operation of the Fermi 2
8 Power Plant. I fully supported the reasonableness of the Nuclear Generation
9 Projects with the total historical period actual expenditures of approximately
10 \$154.0 million, and the projected capital expenditures of approximately \$265.2
11 million and \$187.1 million for the 24-month bridge period ending December 31,
12 2025, and the 12-month projected test period ending December 31, 2026,
13 respectively as depicted on line 4, page 1 of Exhibit A-12, Schedule B5.3
14 throughout my direct testimony.

15

16 The Commission should not adopt Witness Coppola's proposals so that DTE
17 Electric can continue with its work plans to operate the Fermi 2 Power Plant safely
18 and reliably as discussed in my direct testimony.

19

20 **Q8. How did Witness Coppola arrive at the proposed reduction of approximately**
21 **\$77.7 million of Nuclear Generation capital expenditures?**

22 A8. Witness Coppola proposed reductions of approximately:

- 23 • \$2.4 million for the Security System Computer project (Witness Coppola's
24 direct testimony at lines 1-5, page 54)

Line
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- 1 • \$1.3 million for the Plant Radio System (Witness Coppola's direct
- 2 testimony at lines 1-2, page 55)
- 3 • \$12.6 million for Underground Safety-Related Service Water Piping project
- 4 (Witness Coppola's direct testimony at line 2-4, page 56)
- 5 • \$24.3 million for Routine and Small Nuclear projects, specifically three
- 6 projects: Document Management System Enhancements, Reactor
- 7 Recirculation System (RRS) Replacements, and Natural Draft Cooling
- 8 Towers (Witness Coppola's direct testimony at lines 1-4, page 57), and
- 9 • \$37.0 million for Non-Routine and Large Projects, specifically three
- 10 projects: Turbine Controls Replacements, Reactor Recirculation Motor-
- 11 Generator (RRMG) Replacements, and Circulating Water (CW) Traveling
- 12 Screens (Witness Coppola's direct testimony at lines 1 - 5, page 58)

13

14 **Q9. What are your thoughts concerning Witness Coppola's proposal to reduce**
15 **approximately \$37.0 million of rate base for Nuclear Generation Non-Routine**
16 **and Large Projects that he asserts are "still in the very early stage of**
17 **development and premature to include in rate base in this rate case" at line 2,**
18 **page 58 of his direct testimony?**

19 A9. My direct testimony supports the necessity, reasonableness, and prudence of these
20 project expenditures. Witness Coppola is directionally correct in his assertion that
21 these projects are in their initial years; however, Witness Coppola appears to be
22 making only an accounting argument as the basis for excluding these projects, so I
23 refer to DTE Electric Witness Uzenski's discussion in her revised direct testimony
24 at Q87 starting on page TMU-47 that confirms that "projects that do not go into
25 service during the projected test period have no impact on the Company's revenue

Line
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1 requirement and deficiency.” DTE Electric added the in-service year projection to
2 Exhibit A-12, Schedule B5.3, pages 2 – 4, column (g) to make clear the project in-
3 service dates (and thus the project’s potential to impact revenue requirement) where
4 DTE Electric projected placing Turbine Controls Replacements project (page 4,
5 line 15), Reactor Recirculation Motor-Generator (RRMG) replacements (page 4,
6 line 22) and Circulating Water (CW) traveling screens (page 4, line 25) in-service
7 in 2030, 2028 and 2027 respectively.

8

9 **Q10. What are your thoughts concerning Witness Coppola’s proposal to reduce**
10 **approximately \$24.3 million of rate base for Nuclear Generation Routine and**
11 **Small Projects that he asserts are “still in the very early stage of development**
12 **and premature to include in rate base in this rate case” at line 1, page 57 of his**
13 **direct testimony?**

14 A10. My direct testimony supports the necessity, reasonableness, and prudence of these
15 project expenditures. I will address Natural Draft Cooling Towers project later in
16 my rebuttal testimony; otherwise, as with my discussion regarding the Non-Routine
17 and Large projects above, DTE Electric Exhibit A-12, Schedule B5.3, pages 2 - 4
18 depicts DTE Electric projected placing the Document Management System
19 Enhancements project (page 3, line 52) and Reactor Recirculation System (RRS)
20 Replacements (page 3, line 59) in-service in 2028 and 2027 respectively.
21 Furthermore, consistent with the accounting explained by Witness Uzenski that
22 these (Document Management System Enhancements and RRS) “projects that do
23 not go into service during the projected test period have no impact on the
24 Company’s revenue requirement and deficiency.” (Reference Witness Uzenski
25 revised direct testimony at TMU-48, line 2).

Line
No.

1 **Q11. How do you respond to the AG’s proposals for complete disallowance of**
2 **projected expenditures by the Commission that support projects that have**
3 **their in-service dates extend beyond the test period?**

4 A11. I disagree. Throughout my direct testimony, I emphasized that DTE Electric’s focus
5 on nuclear safety and its prioritization of long-term reliability at the Fermi 2 Power
6 Plant support the inclusion of multi-year projects—even those with in-service dates
7 beyond the test period. These projects are appropriate for inclusion when the
8 Company has determined the need to initiate them, provided that proper accounting
9 and ratemaking treatment is applied. This approach demonstrates the Company’s
10 disciplined commitment to maintaining safe and reliable Fermi 2 operations over
11 the long term. The Company requests that the Commission find the total Nuclear
12 Generation capital expenditures to be reasonable and prudent as these investments
13 are consistent with the Company’s prioritization of nuclear safety and its
14 commitment to maintaining long-term reliability at the Fermi 2 Power Plant. While
15 certain projects may not directly impact revenue requirements in this case, they
16 represent necessary, well-justified expenditures and a Commission determination
17 affirming their appropriateness for accounting and ratemaking purposes—rather
18 than disallowance—is fully warranted.

19

20 **Q12. Why are you discussing Witness Coppola’s proposed \$10.0 million capital**
21 **expenditure reduction for Natural Draft Cooling Towers separately from the**
22 **other Routine and Small Projects noted above?**

23 A12. Unlike the Document Management System Enhancements project and the Reactor
24 Recirculation System (RRS) Replacements projects which do not necessarily
25 impact revenue requirement as their in-service dates extend beyond the 12-month

Line
No.

1 projected test period ending December 31, 2026, the Natural Draft Cooling Towers
2 project has an “Annual” in-service designation as shown in DTE Electric Exhibit
3 A-12, Schedule B5.3, page 3, line 61, column (g) meaning this type of routine
4 capital activity can initiate and complete within one year and thus impacts the
5 Company’s revenue requirement. Exhibit A-20, Schedule J2, page 25 describes the
6 Natural Draft Cooling Tower project for the periods relevant to this proceeding
7 including work completed in 2024 and projected work scope to replace 22 bays of
8 fill in 2026.

9

10 **Q13. Is it accurate to classify Natural Draft Cooling Tower project as a subset of**
11 **“projects that have not been started” as Witness Coppola asserts at page 56 of**
12 **direct testimony at line 18?**

13 A13. No. The project is reoccurring and ongoing as the Company provided in discovery
14 (Coppola Exhibit AG-15, pages 1-4). The Natural Draft Cooling Towers completed
15 work scope in Refueling Outage 22 (Cycle 22/RF22 in 2024) and also has approved
16 work scope for years 2025–2026 (Cycle 23/RF23) and 2027-2028 (Cycle24/RF24).
17 Sourcing of services and materials is complete with projected in-service of June
18 2026. The Company only classified implementation (page 4, second column from
19 right (f)) of Cycle 23/RF23 and Cycle 24/RF24 as “Not started” which is consistent
20 with work not scheduled to restart implementation with the replacement of 22 bays
21 of fill until 2026.

22

23 **Q14. Why is the Natural Draft Cooling Tower project not a continuous project until**
24 **it completes?**

Line
No.

1 A14. DTE Electric considers the Natural Draft Cooling Towers project as reoccurring as
2 there's three reasons why Natural Draft Cooling Tower project is planned as a non-
3 continuous project: 1) Although project replacement activities can occur while the
4 Fermi 2 Plant is online, such scope typically does not occur during the warmer
5 months of summer and early fall, 2) the project plan is modular – meaning as
6 Nuclear Generation priorities adjust, Natural Draft Cooling Tower replacement
7 activities can be pulled ahead and executed to support other priorities in other years
8 and 3) planning and execution of Natural Draft Cooling Tower fill replacement
9 scope is proceduralized which allows for only a few months to elapse from the start
10 of implementation planning, material ordering and completion of the scheduled
11 replacement activities.

12

13 **Q15. Why would DTE Electric not schedule Natural Draft Cooling Tower work**
14 **during the warmer summer months?**

15 A15. Thermal efficiencies of the natural draft cooling towers prevent work activity
16 during the warmer summer months. Replacing bays of fill requires removing
17 portions of the cooling towers from service during the project which lessens the
18 cooling capacity of the cooling towers which in turn raises the inlet temperature of
19 the circulating water which in turn reduces the cooling capacity of the main unit
20 condenser which can cause the loss of megawatts or in certain scenarios cause a
21 plant derate or a full plant shutdown.

22

23 **Q16. When would planning be expected to begin for Natural Draft Cooling Towers**
24 **if implementation is scheduled in 2026?**

Line
No.

1 A16. DTE Electric uses industry standard planning milestones for online and cycle work
2 planning, preparation and execution. The previous similar work to replace cooling
3 tower fill started planning in February 2019 and work was completed in May 2019.
4 Exhibit A20, Schedule J2, page 25 explains that there are two natural draft cooling
5 towers, each with 84 bays of fill – this project continues DTE Electric’s efforts to
6 replace the cooling tower fill and improve the cooling tower performance margins.

7

8 **Q17. What are your thoughts concerning Witness Coppola’s proposal to reduce**
9 **approximately \$2.4 million of capital expenditures for the Security System**
10 **Computer?**

11 A17. The Security System Computer project is an infrequent, complex undertaking with
12 several scoping changes as I explained in my direct and rebuttal testimonies of Case
13 No. U-21534. I explain in my response to AGDE-1.24a (Witness Coppola Exhibit
14 AG-13, page 1) the \$2.4 million adjustment in total project capital expenditures
15 was to support “additional site acceptance testing, addition of new cameras and
16 microwave zones, additional updates to cyber assessments and final system
17 adjustments.” The actions taken still are necessary, reasonable, and prudent for the
18 Company to support the Fermi 2 Physical Protection Plan even if the activities are
19 incremental to the prior approved total cost projection.

20

21 **Q18. Why did the Company have to perform additional on-site testing, additional**
22 **updates to cycle assessments and final system adjustments?**

23 A18. The project included and anticipated factory acceptance testing and on-site testing
24 prior to in-servicing. However, that testing revealed unsatisfactory performance
25 from the integrated system. Though the components of the system passed their

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1 factory acceptance testing and the initial integrated testing was completed without
2 issue, the more complex security scenarios challenged the replacement system to
3 respond as designed. The incremental \$2.4 million of project expenditures
4 supported understanding and mitigating these challenges.

5

6 **Q19. Has the Security System Computer project “mushroomed into a very costly**
7 **project with significant cost overruns” as asserted by Witness Coppola on page**
8 **53 of his direct testimony at line 12?**

9 A19. No. As I discussed in my direct testimony, the Security System Computer project
10 replaced a significant portion of the Fermi 2 security equipment which is required
11 to operate as designed to support the NRC-regulated Fermi 2 Physical Protection
12 Plan. The change in total projected cost was reported as approximately 6% in my
13 response to AGDE-1.24a (Witness Coppola Exhibit AG-13, page 1) supported by
14 rationale detailing the basis for the incremental costs necessary to in-service this
15 project.

16

17 **Q20. What are your thoughts concerning Witness Coppola’s proposal to reduce**
18 **approximately \$1.3 million of capital expenditures for the Plant Radio**
19 **System?**

20 A20. The Plant Radio System project is an infrequent, complex undertaking with several
21 scoping changes as I explained in my direct and rebuttal testimonies of Case No.
22 U-21534. I explain in my response to AGDE-1.25a (Witness Coppola Exhibit AG-
23 13, page 2) the \$1.3 million adjustment in total project capital expenditures was to
24 support “additional system adjustments following on-site equipment initiation. (i.e.
25 real-world performance led to unanticipated radio signal dead spots which is

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1 unacceptable for this plant system. DTE Electric with supplier and other expertise
2 tested the design and install to optimize equipment performance.” The actions taken
3 still are reasonable and prudent for the Company to support the Fermi 2 operations,
4 Fermi 2 Emergency Response, and the Fermi 2 Physical Protection Plan even if the
5 activities are incremental to the prior approved total cost projection.

6

7 **Q21. Why did the Plant Radio System have to incur incremental design and install**
8 **to optimize equipment performance?**

9 A21. The project included and anticipated factory acceptance testing and on-site testing
10 prior to in-servicing revealed unsatisfactory performance from the integrated
11 system. Though the components of the system passed their factory acceptance
12 testing and the initial integrated testing was completed without issue, Nuclear
13 Generation still experienced equipment issues which resulted in lost frequencies
14 and dead spots within certain areas of the Fermi 2 plant. These equipment issues
15 could not be reasonably foreseen as the issues were unique to the complex and
16 competing phenomenon of Fermi 2 usage demands and the exact environment
17 where the equipment is located.

18

19 **Q22. Are the Plant Radio System and Security System Computer projects in-**
20 **service?**

21 A22. Yes. As I stated in my direct testimony at line 18 of page JCD-23, Security System
22 Computer was placed in-service in February 2025 and at line 20 of page JCD-27,
23 Plant Radio System was also placed in-service in February 2025.

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1 **Q23. Do the incremental capital expenditures for Security System Computer and**
2 **Plant Radio System support reasonable and prudent outcomes?**

3 A23. Yes. DTE Electric's replacement of what had been an aging security system
4 computer with degrading margins with the Security System Computer project
5 addressed feedback from the NRC in past evaluations and completing the Plant
6 Radio System provides DTE Electric's Nuclear Security with additional
7 communication systems margins.

8

9 **Q24. What are your thoughts concerning Witness Coppola's proposal to reduce**
10 **approximately \$12.6 million of capital expenditures related to the**
11 **Underground safety-related service water piping project?**

12 A24. As I highlighted in Case No. U-21534, relying on internal Company project
13 authorization forms can lead to misunderstandings and misconceptions regarding
14 actual project performance – as the initial full authorization for the Underground
15 Safety-Related Service Water Piping project was \$58.8 (labeled as “Previous
16 Request(s)” in Witness Coppola Exhibit AG-14, page 3) with an approved change
17 of \$44.3 million (labeled as “Current Capital Approval Request” in Witness
18 Coppola Exhibit AG-14, page 3) to bring total authorized expenditures to \$103.0
19 million. While approximately \$3.8 million of this change was due to establishing
20 contingency (ultimately not used), approximately \$21.0 million of the change
21 request (Outage Shared Cost – \$12.6 million, Nuc A&G - \$5.8 million and
22 Corporate OH - \$2.6 million) resulted in no change in Nuclear Generation total
23 capital expenditures but simply noted where certain shared capital expenditures
24 should be reflected at the project-level.

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1 **Q25. Did transferring the Underground Safety-Related Service Water Piping**
2 **project from “MEP to Fermi Capital” contribute to increased Nuclear**
3 **Generation capital expenditures as asserted by Witness Coppola on page 55 of**
4 **his direct testimony at lines 17 - 19?**

5 A25. No. The “MEP to Fermi Capital” quote is a shorthand phrase used in an internal
6 DTE Electric deliberation. The full context of the “MEP to Fermi Capital” quote
7 used by Witness Coppola is “Outage Shared Cost 12.6M – Due to moving from
8 MEP to Fermi Capital.” I explain in my direct testimony at Q31 (JCD-15) projects
9 executed during refueling outages must account for a portion of services, materials
10 and personnel that are shared across all outage activities and projects; the capital
11 costs associated with these shared activities is bounded in total through reasonable
12 and prudent execution of the refuel outage. In this specific project, the original
13 budget request as developed by the Major Enterprise Projects (MEP) organization
14 did not include these shared activities in its original budgeting appropriation
15 request. These shared capital expenditures were always going to be incurred by
16 Nuclear Generation. Though the project had initially budgeted for those shared
17 costs to be absorbed by other capital projects, which would have been
18 inappropriate. In response, the subsequent capital appropriation request, this time
19 submitted by the Fermi Nuclear Generation organization, incorporated lessons
20 learned from the RF21 (spring 2022) implementation work into the RF22 (spring
21 2024) work plan, and simultaneously corrected the prior exclusion by appropriately
22 including the projected shared services costs. In other words, the \$12.6 million of
23 expenditure did not arise as a consequence of, and was not influenced by, the
24 internal DTE organization where it was allocated or the execution of the project.
25 Furthermore, the \$12.6 million expenditure was not additional or incremental.

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1 Witness Coppola appears to have incorrectly attributed additional meaning to an
2 internal communication concerning allocation of expected, reasonable, and prudent
3 expense.

4

5 **Q26. How would you recommend reviewing Nuclear Generation capital**
6 **expenditures?**

7 A26. I recommend reviewing capital expenditures in the aggregate as that is a reasonable
8 and prudent approach given the potential nuclear safety and reliability implications
9 of disallowing a specific project. DTE Electric manages Nuclear Generation in the
10 aggregate to complete scope depicted subject to the nuclear safety priority. My
11 direct testimony supports that DTE Electric is expending capital in a reasonable
12 and prudent manner in support of the nuclear safety priority and safe and reliable
13 plant operations. The Fermi 2 Power Plant performance demonstrates that the
14 Nuclear Generation capital expenditures and operating expenses are delivering safe
15 and reliable, carbon-free electricity generation for our communities.

16

17 **Q27. Did Witness Coppola also propose adjustments to Nuclear Generation's**
18 **operating expenses for the 12-month projected test period ending December**
19 **31, 2026?**

20 A27. Yes. Witness Coppola proposed reducing the Nuclear Generation operating
21 expenses for the 12-month period ending December 31, 2026, by approximately
22 \$5.8 million from DTE Electric's \$160.0 million as depicted in Exhibit A-13,
23 Schedule C5.3, page 1, row 24, column (o) to the approximately \$154.2 million as
24 depicted in Witness Coppola Exhibit AG-51, page 1, row 24, column (o).

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1 **Q28. What are your thoughts concerning Witness Coppola’s proposed Nuclear**
2 **Generation operating expense reduction of approximately \$5.8 million for the**
3 **12-month projected test period ending December 31, 2026?**

4 A28. Witness Coppola calculates his proposed Nuclear Generation operating expense
5 reduction of approximately \$5.8 million. He essentially eliminated Nuclear
6 Generation’s adjustment of historical expenses for “Staffing temporarily below
7 long-term sustainable threshold” and changed the basis from the actual Nuclear
8 Generation operating expenses for 12-month historical period ending December 31,
9 2023, to the actual Nuclear Generation operating expenses for the 12-month
10 historical period ending December 31, 2024. I’ll discuss next in my rebuttal
11 testimony the inappropriateness of Witness Coppola’s assertions underlying his
12 proposed Nuclear Generation O&M operating expenses reductions.

13

14 **Q29. Are Nuclear Generation’s operating expenses as depicted in Exhibit A-13,**
15 **Schedule C5.3 “outdated” as Witness Coppola asserts at lines 11-12 of his**
16 **direct testimony on page 125?**

17 A29. No. My direct testimony fully explains the necessary, reasonable and prudent
18 adjustments to arrive at Nuclear Generation’s projected operating expenses for the
19 12-month projected test period ending December 31, 2026. The 2023 historical year
20 normalization adjustment is a reasonable and prudent adjustment that reflects
21 necessary adjustments to the Site Security and Radiological Protection portion of
22 Nuclear Surcharge and to support DTE Electric’s long-term sustainable staffing
23 targets of 720 DTE Electric employees. DTE Electric’s projected Nuclear
24 Generation operating expenses for the 12-month projected test period ending
25 December 31, 2026, of \$160.0 million are reasonable and prudent regardless of

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1 using the 12-month historical period ending December 31, 2023, or using 12-month
2 historical period ending December 31, 2024, as the basis.

3

4 **Q30. Did you include 2024 O&M normalization adjustments?**

5 A30. My direct testimony and exhibits depicted total Nuclear Generation expenses for
6 the 12-month projected test period ending December 31, 2026 of \$160.0 million
7 (Exhibit A-13, Schedule C5.3, page 1, line 24, column (o)) using actual expenses
8 from the 12-month historical period ending December 31, 2023, and applying
9 several adjustments including a 2023 normalization adjustment of \$5.2 million
10 (Exhibit A-13, Schedule C5.3, page 1, line 24, column (g), note 3). Witness
11 Coppola introduced a company discovery response that included a Nuclear
12 Generation 2024 O&M normalization adjustment in his direct testimony and
13 exhibits with the 12-month projected test period ending December 31, 2026, of
14 \$160.5 million (Witness Coppola Exhibit AG-50, page 2, line 24, column (o)) using
15 actual expenses from the 12-month historical period ending December 31, 2024,
16 and applying several adjustments including a 2024 normalization adjustment of
17 \$4.9 million (Witness Coppola Exhibit AG-50, page 2, line 24, column (g), note 3).

18

19 **Q31. Why are the 2024 normalization adjustments necessary?**

20 A31. Both the historical 12-month periods ending December 31, 2023, and 2024
21 expenses reflect short-term lower expenses because the Fermi 2 Power Plant
22 operated at staffing levels below the 'long-term sustainable threshold' where I
23 discuss the 2023 normalization adjustment in my direct testimony on page JCD-74
24 at Q138 (line 21) and on page JCD-75 at Q139 (line 7). The 'long-term sustainable
25 threshold' staffing levels by Nuclear Generation organization were further provided

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1 by DTE Electric is response to discovery AGDE-1.36d(iii) as depicted in Witness
2 Coppola Exhibit AG-50, page 4, column (g) which represents the long-term
3 organizational targets DTE Electric has projected to achieve safe and reliable
4 operations while meeting each organization's obligations under the plant's
5 licensing basis as described in the Fermi 2 Updated Final Safety Analysis Report
6 (USFAR) Chapter 13 Conduct of Operations provided by the Company and
7 publicly available at nrc.gov.

8

9 **Q32. What adjustment did AG Witness Coppola propose?**

10 A32. Witness Coppola proposed a reduction of \$5.8 million to Nuclear Generation's
11 O&M operating expense for the 12-month projected test period ending December
12 31, 2026, on page 127 of his direct testimony at line 1. Witness Coppola's proposed
13 reduction was calculated by eliminating the 2024 normalization adjustment of \$4.9
14 million (Witness Coppola Exhibit AG-50, page 2, line 24, column (g), note 3) to
15 calculate an updated adjusted historical test period expense for the 12-month period
16 ending December 31, 2024, of \$153.1 million (Witness Coppola Exhibit AG-51,
17 page 1, line 24, column (h)), Witness Coppola then adjusted the inflation factors
18 applied for the 12-month projected periods ending December 31, 2025, and 2026,
19 from 3.00% and 3.10% respectively in Witness Coppola Exhibit AG-50, page 2,
20 note 4 to 2.8% and 2.4% respectively in Witness Coppola Exhibit AG-51, page 1,
21 note 4 to calculate an total operating expense for the 12-month projected test period
22 ending December 31, 2026, of \$154.2 million (Witness Coppola Exhibit AG-51,
23 page 1, line 24, column (o)) which is \$5.8 million less (Witness Coppola Exhibit
24 AG-51, page 1, line 26, column (o)) than the \$160.0 million originally depicted in

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1 in Exhibit A-13, Schedule C5.3, page 1, line 24, column (o) (Witness Coppola
2 Exhibit AG-51, page 1, line 25, column (o)).

3

4 **Q33. What is AG Witness Coppola's basis for his proposal?**

5 A33. Witness Coppola inappropriately asserts on page 126 of his direct testimony at lines
6 12-13 that "the nuclear plant can operate comfortably at a lower employee level"
7 than the 720 DTE Electric staffing levels depicted in his Exhibit AG-50, page 4,
8 column (g). Witness Coppola further inappropriately asserts on page 126 of his
9 direct testimony at lines 3-4 that "[a]pparently, the nuclear operation participated
10 in the Company's temporary cost reduction efforts in 2023 and reduced some staff
11 members."

12

13 **Q34. Do you agree with AG Witness Coppola's proposed adjustment?**

14 A34. No. I do note that Nuclear Generation employees did not participate in the
15 Company's Voluntary Separation Incentive Program (VSIP) nor did DTE Electric
16 purposely reduce Fermi 2 staffing in support of a short-term expense savings
17 program. Nuclear Generation personnel are critical operations employees. In my
18 response to Staff discovery request STDE-14.5a (Rebuttal Exhibit A-47, Schedule
19 MM1, page 1) highlights that DTE Electric hired approximately 52 new employees
20 and transferred another approximately eight employees from elsewhere in the
21 Company to Nuclear Generation in 2024 in ongoing efforts to offset attrition. DTE
22 Electric has a reasonable and prudent 'long-term sustainable' organizational
23 staffing plan of 720 DTE Electric employees as depicted in Witness Coppola's
24 Exhibit AG-50, page 4, column (g) and as such the total Nuclear Generation O&M
25 operating expenses of \$160.0 million for the 12-month projected test period ending

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December 31, 2026, as depicted in Exhibit A-13, Schedule C5.3, page 1, line 24, column (o) are a reasonable and prudent forecast. Nuclear Generation's projected O&M expenses of \$160.0 million for the 12-month projected test period ending December 31, 2026, represent no change from the Commission's Case No. U-21534 Order dated January 23, 2025 (page 218) such that DTE Electric is actively recruiting personnel to fill open positions at Fermi 2 Power Plant consistent with that Order as highlighted in my response to Staff discovery STDE-14.5b (Rebuttal Exhibit A-47, Schedule MM1, page 2).

Q35. What are the risks if these normalization adjustments are disallowed?

A35. DTE Electric must continue to operate the Fermi 2 Power Plant with the overriding operating priority as nuclear safety and in support of safe and reliable Fermi 2 operations. The 'long-term sustainable staffing' plan supporting DTE Electric's projected Nuclear Generation operating expenses of \$160.0 million for the 12-month projected test period ending December 31, 2026, is reasonable and prudent and supports the stated nuclear safety priority. As I highlighted in my discovery response to STDE-14.5d (Rebuttal Exhibit A-47, Schedule MM1, page 4), recruiting, hiring, training and qualifying individuals to safely operate Fermi 2 Power Plant, consistent with its NRC operating license, is a continuous process with a years-long forward-looking view required. Adjusting a nuclear power plant's operating expenses and staffing levels using a one- or two-year snapshot would not be reasonable and would not be prudent.

Q36. Does this conclude your rebuttal testimony?

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

REBUTTAL TESTIMONY

OF

STEVEN B. AMBROSE

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF STEVEN B. AMBROSE

Line
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1 **Q1. Please state your full name, title, business address and by whom you are**
2 **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. Did you file direct testimony in this proceeding on behalf of DTE Electric**
8 **Company (DTE Electric or Company)?**

9 A2. Yes.
10

11 **Purpose of Testimony**

12 **Q3. What is the purpose of your rebuttal testimony?**

13 A3. The purpose of my rebuttal testimony is to address the disallowances proposed by
14 Witnesses Rogers, Klocke and Zichi on behalf of Michigan Public Service
15 Commission (MPSC or Commission) Staff and Witness Coppola on behalf of
16 Attorney General Dana Nessel (AG). Specifically, my rebuttal testimony will
17 provide responses across the following topics:

18 1. Staff Witness Rogers' recommendation for a 20% disallowance of costs relating
19 to IT projects with a Level 2 cost estimate in capital expenditure of \$0.685
20 million for the test year ending December 31, 2026, and in O&M expenditure
21 of \$0.016 million for the test year ending December 31, 2026.

22 2. Staff Witness Rogers' recommendation for a 10% disallowance of costs relating
23 to IT projects with a Level 3 cost estimate in capital expenditure of \$13.077
24 million for the bridge year ending December 31, 2025, capital expenditure of
25 \$11.367 million for the projected test year ending December 31, 2026 and

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- 1 O&M expenditure of \$2.488 million for the combined bridge period ending
2 December 31, 2025 and projected test year ending December 2026.
- 3 3. Staff Witness Rogers' recommendation for a full disallowance of the Projected
4 Capital Overhead and Other Costs (Capital) for all projects with spend not
5 already approved in Case Number U-21534.
- 6 4. Staff Witness Rogers' recommendations on individual project disallowances of:
- 7 o Corporate Instance – Maximo Application Suite Upgrade project
8 costs of \$1.411 million in capital expenditures for the projected test
9 year ending December 31, 2026.
- 10 o Maximo Engineering Process Automation project costs of \$2.552
11 million in capital expenditures for the 2024 bridge year in recovery.
- 12 o The Backup Environmental Growth project costs of \$0.1 million in
13 capital expenditures for the bridge period ending December 31,
14 2025, and \$0.1 million in capital expenditures for the projected test
15 year ending December 31, 2026.
- 16 o The Network Hardening and Operations project costs of \$0.5
17 million in capital expenditures for the test year ending December 31,
18 2026.
- 19 o The Digital Worker Experience Electric EOL project costs of \$1.563
20 million in capital expenditures for 2023 historical year, \$4.034
21 million in capital expenditures for the bridge period (\$2.825 million
22 in 2024 and \$1.209 million in 2025) and \$0.789 million in capital
23 expenditures for the projected test year ending December 31, 2026.

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- 1 o The Field Worker Device EOL project costs of \$0.135 million in
- 2 capital expenditure for the projected test year ending December 31,
- 3 2026.
- 4 o The DO Productivity Center project costs of \$0.439 million in
- 5 capital expenditure for the bridge period ending December 31, 2024.
- 6 5. Staff Witness Zichi's recommendation for a full project disallowance of:
- 7 o The Communication Compliance and Data Loss Prevention (DLP)
- 8 Diversification project costs of \$0.186 million in capital
- 9 expenditures for the bridge period ending December 31, 2025, and
- 10 \$0.184M in capital expenditures and \$0.283 million in O&M
- 11 expenditures for the test year ending December 31, 2026.
- 12 6. Staff Witness Klocke's recommendations for full disallowances of
- 13 o The Customer Insight Platform Application Health project costs of
- 14 \$4.275 million in capital expenditures and \$0.100 million in O&M.¹ for
- 15 projected test year ending December 31, 2026.
- 16 o The Customer Relationship and Billing (CR&B) Program costs of
- 17 \$6.310 million in capital expenditures and \$2.695 million in O&M for
- 18 projected test year ending December 31, 2026.
- 19 o DTE Mobile App Application Health project costs of \$1.100 million in
- 20 capital expenditures and \$0.170 million in O&M for projected test year
- 21 ending December 31, 2026.
- 22 o Outage WISMO, PPS, and Map Application Health costs of \$3.000
- 23 million in capital expenditures for the bridge period ending December

¹ Staff Witness Klocke pp 4 (incorrectly stated that the \$0.100 million was a capital expenditure. This cost is O&M as indicated in the Exhibit A-24, N3 on line 326)

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1 31, 2025, and \$5.250 million in capital expenditures and \$0.250 million
2 O&M costs for projected test year ending December 31, 2026.

3 o Outage WISMO, PPS, and Map Enhancement costs of \$1.700 million
4 in capital expenditures and \$0.525 million in O&M for projected test
5 year ending December 31, 2026.

6 o Payment Merchant Fees project costs of \$9.998 million in capital costs
7 for the bridge year ending December 31, 2025.

8 7. AG Witness Coppola's recommendations for disallowances of:

9 o \$2.5 million of O&M adjustment for 2024 forecast for NICE software
10 implementation.

11 o \$5.68 million cost to achieve line item for projected test year ending
12 December 31, 2026 to support new IT projects.

13

14 The absence of a discussion of any other matters not listed above, and not included
15 in my rebuttal testimony, should not be taken as an indication of agreement with
16 other aspects of any witness's testimony in the instant case.

17

18 **Q4. Are you sponsoring any exhibits in this proceeding?**

19 A4. Yes, I am sponsoring the following exhibits:

20	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
21	A-44	JJ1	MPSC Staff's Answer to DTE Electric Company's
22			Second Discovery Request
23	A-44	JJ2	Level 3 Over Recovery Analysis
24	A-44	JJ3	Correction DR-1.4-01 Level 3 Projects Implemented

25

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1 **Q5. Were the exhibits prepared by you or under your direction?**

2 A5. Yes, they were.

3

4 **Staff -Witness Rogers Proposed Disallowances**

5 IT Projects with a Level 2 Cost Estimate:

6 **Q6. What disallowances did Staff propose related to IT Capital projects with a**
7 **Level 2 cost estimate?**

8 A6. Staff Witness Rogers recommended a 20% disallowance of costs relating to IT
9 projects with a Level 2 cost estimate. Her recommendation impacts 5 of the 8
10 projects with a Level 2 cost estimate. The resulting disallowance supported by Staff
11 Witness Rogers is \$0.685 million in the 2026 projected test year as well as \$0.016
12 million in O&M in the 2026 projected test year².

13

14 **Q7. What reasons does Staff Witness Rogers provide for the proposed**
15 **disallowances for projects with a Level 2 cost estimate?**

16 A7. In her testimony, Staff Witness Rogers recommends a 20% disallowance for
17 projects with Level 2 cost estimates, because she claims these estimates are
18 considered immature and unreliable. Level 2 estimates are made at least one to two
19 years before implementation, during which project scope, timeline, and priority can
20 change, particularly in fast-moving technology. Although the Company states that
21 costs, scope, and execution decisions are finalized with executive approval at this
22 stage, Staff found that changes still occur. Staff also compared actual project costs
23 from this case to Level 2 estimates in Case U-21297. Of 147 projects with both
24 estimates and actual costs, 94 (64%) had higher estimates than actual costs,

² Staff Witness Rogers Exhibit S-12.1

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1 resulting in over-recovery, while 53 (36%) had lower estimates, leading to under-
2 recovery. Staff Witness Rogers asserts that these results show Level 2 estimates fall
3 far outside the Company's claimed accuracy range of -15%/+20%, confirming they
4 are imprecise and premature. She further testifies that the 20% recommended
5 disallowance is consistent with Staff's position in prior cases. Citing the
6 Association for the Advancement of Cost Engineering (AACE) Cost Estimate
7 Classification System 17R-97, she noted that Level 2 cost estimates most closely
8 align with Class 3 estimates, which have an expected accuracy range of +20%/-
9 30%. The 20% recommended disallowance is therefore also less than the 30%
10 lower bound of the AACE Class 3 estimate range³
11

12 **Q8. Do you agree with Staff Witness Rogers' 20% disallowance recommendation?**

13 A8. No, I do not agree with Staff Witness Rogers' blanket 20% disallowance to all
14 Level 2 estimates for several reasons.

15 First, Level 2 cost estimates, as developed and applied to IT projects during the
16 approval process, are comprehensive by cost type and by project phase. The
17 estimates are developed through input and reviews from IT subject matter experts
18 (SME) teams based on Scope, Technology, historical data, and vendor quotes.
19 These SME teams have hands-on, day-to-day practical knowledge and experience
20 with the Company's IT needs and IT infrastructure. Their familiarity with the
21 Company's Technology systems and prior implementation of same provides
22 technical and expert insight into shaping project estimates. SMEs also contribute
23 lessons learned from past projects, ensuring that assumptions are grounded. All
24 Level 2 estimates support the Company's project funding and prioritization
25 decisions. These estimates reflect increased granularity and confidence across

³ Staff Witness Rogers pp. 8-13

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1 labor, non-labor, and vendor cost categories and are reviewed through well-
2 established formal governance and decision-making channels. Staff Witness
3 Rogers' assertion that Level 2 estimates are "immature and imprecise" is simply
4 incorrect; rather, any changes to project costs that occur post estimate arise from
5 legitimate adjustments in project scope or requirements identified after the Level 2
6 estimate are established. Such changes are a natural consequence of the project
7 design and execution process and do not reflect a flaw or deficiency in the initial
8 estimate.

9 Second, Company Witness Robertson's direct testimony and Exhibit A-34,
10 Schedule Y2 Summary of the AACE Cost Estimate Classification System, properly
11 interprets AACE RP No. 18R-97 as being inappropriate for IT project cost
12 estimation. By its own terms, AACE RP No. 18R-97 applies to engineering,
13 procurement, and construction activities for process industries. "*Process*
14 *Industries*" for purposes of AACE RP No. 18R-97 is defined as firms involved with
15 the manufacturing and production of chemicals, petrochemicals, and hydrocarbon
16 processing. Thus, the guidance provided by AACE RP No. 18R-97 is not applicable
17 to IT project cost estimation. Finally, taking a position in a case because that same
18 position was taken in a previous case is not sufficient justification. The blanket
19 disallowance disregards evidence of record that is specific to this proceeding.

20

21 **Q9. Should the Commission accept Staff Witness Rogers' recommendation for a**
22 **20% disallowance of costs for the IT projects with Level 2 cost estimates?**

23 A9. No, for the reasons stated above, the Commission should reject the proposed
24 Capital disallowance by Staff Witness Rogers of \$0.685 million for 2026 and
25 associated O&M of \$0.0016 million.

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1 IT Projects with a Level 3 Cost Estimate:

2 **Q10. What disallowances did Staff Witness Rogers propose in her testimony related**
3 **to IT capital projects with a Level 3 cost estimate (Staff Witness Rogers, page**
4 **13, lines 15-19)?**

5 A10. Staff recommends a 10% disallowance of costs for IT projects with a Level 3 cost
6 estimate totaling \$13.077 million in Capital expenditures for the bridge year ending
7 December 31, 2025, and \$11.367 million in capital investment and \$2.488 million
8 in O&M expenditures for the projected test year ending December 31, 2026⁴.

9

10 **Q11. Did Staff Witness Rogers propose an updated O&M disallowance related to**
11 **IT capital projects with a Level 3 cost estimate?**

12 A11. Yes. In response to a discovery request from DTE Electric, Staff Witness Rogers
13 confirmed that 10% of the individually disallowed O&M was also included in the
14 total O&M disallowance from Level 3 disallowances. Adjusting for this overlap,
15 Staff's correct proposed O&M disallowance for projects in Level 3 changes from
16 \$2,487,790 to \$2,085,539. See my Rebuttal Exhibit A-44 JJ1 MPSC Staff's Answer
17 to DTE Electric Company's Second Discovery Request, DEST-2.1.

18

19 **Q12. What reasons does Staff Witness Rogers provide for the proposed**
20 **disallowances for projects with a Level 3 cost estimate?**

21 A12. Staff Witness Rogers asserts in her testimony that a 10% disallowance should apply
22 to projects with Level 3 cost estimates because they are inaccurate. She explains
23 that, of 159 projects reviewed, 48% showed over-recovery averaging 34%, 46%
24 showed under-recovery averaging 45%, and 9 projects had no change, all of which

⁴ Staff Witness Rogers pp 13-16

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1 fall outside the Company's stated -10%/+15% accuracy range. She further testifies
2 that Level 3 estimates are only slightly more precise than Level 2 estimates and are
3 most comparable to AACE Class 2 estimates, which have an accuracy range of -
4 15% to +10%.

5

6 **Q13. Do you agree with Staff Witness Rogers' 10% blanket disallowance**
7 **recommendation for all Level 3 cost estimates?**

8 **A13.** No, I do not agree with Staff Witness Rogers' recommendation that the
9 Commission should impose a blanket 10% disallowance on Level 3 estimates.
10 Level 3 estimates are accurate and comprehensive at their point of development,
11 supporting project requirements and initial budget decisions. Scope changes during
12 execution account for subsequent cost updates, which is a process that is a widely
13 accepted practice in project management.
14 Variances between Level 3 estimates and finalized actual costs reflect project
15 changes (scope, schedule and cost), not estimation errors. Mature estimating
16 practices anticipate and allow for ongoing refinement and adjustment.
17 The approach Staff has used to conduct their analysis, as presented in Exhibit S-
18 12.8, is incomplete, unstructured, and does not represent a widely accepted practice
19 for calculating estimate to actuals variances for a project. Cost estimates should be
20 evaluated over the full project lifecycle, not year by year. Annual variances are
21 common and often driven by legitimate factors such as scope changes, execution
22 delays, or schedule deferrals. Judging estimate accuracy solely on annual spend can
23 create misleading conclusions.
24 However, if historical spend comparisons are deemed necessary, it would be
25 prudent to aggregate planned and actual expenditures across the entire period in

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1 question, such as the combined years 2023 and 2024, and assess performance over
2 this broader timeframe.

3
4 Of the 77 entries presented as individual projects in Witness Rogers' Exhibit S-
5 12.8, only 63 represent unique projects. The remaining 14 entries are duplicative
6 and associated with the multiyear projects and therefore should not be counted
7 separately in the analysis. These 14 entries are highlighted as "Entry tied to Multi
8 Year Project" in Company's Exhibit A-44 JJ2 Level-3 Over Recovery Analysis.

9 Based on the review of the 63 unique projects as presented in Company's Exhibit
10 A-44 JJ2 Level-3 Over Recovery Analysis, please refer to column named
11 "Recovery Status per Company Analysis based on 2023 and 2024 combined spend"

- 12 • 26 projects are within the industry-accepted $\pm 10\%$ variance for spending
13 across the two-year span of 2023 and 2024.
14 • 6 projects show under-recovery- greater than $\pm 10\%$ threshold.
15 • 31 projects show over-recovery – greater than $\pm 10\%$ threshold.

16

17 The 31 over-recovered projects occurred within the two-year timeframe, which may
18 not reflect the entire project lifecycle, as noted earlier. These do not indicate poor
19 estimation accuracy and are explained by documented lifecycle factors, including:

- 20 • 12 projects incurred scope changes - scope adjustment and alignment with other
21 projects due to execution synergies, technical dependencies and business
22 values.

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- 1 • 9 projects benefited from efficiency gains/Cost savings - successful vendor
- 2 negotiations, technical solution re-designs, utilizing existing
- 3 solution/resources, effective resource planning.
- 4 • 4 projects faced schedule change, deferrals to future years or prior years in
- 5 response to evolving business needs.
- 6 • Only 6 projects had true execution variance during the implementation phase
- 7 of project.

8 Additionally, Staff has been provided with a supplemental audit response to DR-
9 1.4, attached hereto as my Rebuttal Exhibit A-44 JJ3 Correction DR-1.4-01 Level
10 3 Projects Implemented, which contains corrections to Audit Response DR-1.4 the
11 Company's analysis now reflects. In conclusion, the cost variances observed,
12 including those exceeding 10%, have been comprehensively explained in my direct
13 testimony and exhibits and are consistent with normal project lifecycle dynamics
14 and professional project management practices.

15

16 **Q14. Should the Commission accept Staff Witness Rogers' recommendation of a**
17 **10% disallowance of costs relating to IT projects with a Level 3 cost estimate?**

18 A14. No, for the reasons stated above, the Commission should reject the proposed
19 disallowances by Staff Witness Rogers of \$13.077 million in Capital expenditures
20 for the bridge year ending December 31, 2025, and \$11.367 million in Capital
21 expenditures and \$2.48 million in associated O&M expenditures for the test year
22 ending December 31, 2026.

23

24 **Projected Overhead & Other Costs (Capital)**

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1 **Q15. Are there any Projected Overhead & Other Costs (Capital) recommended for**
2 **disallowance by Staff Witness Rogers⁵?**

3 A15. Yes, Staff Witness Rogers has recommended a full disallowance of the Projected
4 Overhead and Other Costs (Capital) for all IT projects that have not already been
5 approved in Case No. U-21534, resulting in a recommended disallowance of \$0.731
6 million in the 2023 historical year, \$3.231 million in the bridge period (\$0.284
7 million in 2024 and \$2.947 million in 2025), and \$11.542 million in the 2026
8 projected test year.

9

10 **Q16. Do you agree with Staff Witness Rogers' proposed disallowance of Capital**
11 **Overhead and Other Costs (Capital)?**

12 A16. No, I do not agree with the proposed disallowance and respectfully request that the
13 Commission reject it for the reasons outlined in Company Witness Uzenski's
14 rebuttal testimony⁶.

15

16 Individual IT Project Disallowances:

17 **Q17. Are there any other disallowances relating to IT projects recommended by**
18 **Staff Witness Rogers?**

19 A17. Yes, Staff Witness Rogers recommended a total of \$11.612 million in
20 disallowances for the following IT projects:

- 21 • Digital Worker Experience EOL
- 22 • Corporate Instance - Maximo Application Suite Upgrade
- 23 • Field Worker Device EOL
- 24 • Maximo Engineering Process Automation

⁵ Staff Witness Rogers pp. 16-19

⁶ Company Witness Uzenski Rebuttal pp. 9-11

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- 1 • Backup Environmental Growth
- 2 • Network Hardening and Operations Project
- 3 • DO Productivity Center
- 4

5 **Q18. Please summarize Staff Witness Rogers' proposed disallowance for the Digital**
6 **Worker Experience EOL.**

7 A18. Staff Witness Rogers recommends a disallowance of \$1.563 million in the 2023
8 historical year, \$4.034 million in the bridge period (\$2.825 million in 2024 and
9 \$1.209 million in 2025), and \$0.789 million in the 2026 projected test year because
10 the costs per unit of equipment and the projected cost are not equal.⁷ In Table 3 on
11 page SBA-65 of my direct testimony, I provided the number of laptops, desktops,
12 monitors, tablets, and supplemental field worker devices to be replaced in 2023,
13 2024, 2025, and 2026. In response to a Staff audit request, the Company provided
14 the unit cost of each type of device.⁸ Through an additional round of Staff audit,
15 the Company provided a breakdown of the cost of each docking station, camera,
16 mouse, headset, and dual monitor configuration.⁹ Staff Witness Rogers' Exhibit
17 12.12 analyzes the Digital Worker Experience EOL information provided by the
18 Company and provides Staff's calculations for the cost in each year. Additionally,
19 Exhibit S-12.12, line 9, provides the difference between the Company's projected
20 capital request and the total cost of equipment for each year. Staff Witness Rogers
21 recommends the Commission disallow the difference set forth in Exhibit S-12.12,
22 line 9, because she believes it represents unaccounted for costs beyond what is used
23 to replace equipment that has reached its end of life.

⁷ Staff Witness Rogers, pp. 26-28.

⁸ See Exhibit S-12.11, p. 4.

⁹ See Exhibit S-12.11, p. 5.

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1 **Q19. Do you agree with Staff Witness Rogers' proposed disallowance for the Digital**
2 **Worker Experience EOL?**

3 A19. No, I do not agree with the recommended disallowance. Staff's analysis and
4 calculations relied on the following inaccuracies and incomplete information and
5 should be rejected:

- 6 • DTE Electric's request for 2024, as set forth in U-21860 Exhibit A-12
7 Schedule B5.7.7, totals \$5.021 million. However, Staff inaccurately used
8 \$5.201 million in their calculations, thereby overstating the request by
9 approximately \$180,000.
- 10 • Staff calculated the total cost for headsets, docking stations, and dual
11 monitor configurations based on a quantity of only one unit each. However,
12 DTE Electric's request includes multiple units in varying quantities,
13 amounting to \$251,000 for 2024, \$410,000 for 2025, and \$250,000 for
14 2026. This results in an understatement of material costs by approximately
15 \$908,000 in the Staff's calculations.
- 16 • Additionally, Staff Witness Rogers based her conclusions on information
17 provided in the audit response marked as Exhibit S-12.11, p. 4, which
18 requested individual unit costs for laptops, desktops, monitors, tablets, and
19 supplemental field worker devices related to the Digital Worker Experience
20 Electric EOL project. The audit responses in Exhibit S-12.11, pp. 4-5,
21 contained unit quantities and device costs, but did not include labor costs
22 required for device configuration, deployment, and testing. Notably, labor
23 cost differences amount to approximately \$1.563 million for 2023, \$2.395
24 million for 2024, \$0.799 million for 2025, and \$0.539 million for 2026.

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1 These labor costs are integral and must be included in the total project cost
 2 calculation, as detailed in Tables 1 through 4 below.

3

4

Table 1: Digital Worker Experience (2023)

2023			
Device Type	Count	Avg. cost per device	Amount
Laptop	706	\$ 1,655	\$ 1,168,430
Desktop	1	\$ 1,105	\$ 1,105
Monitor	180	\$ 165	\$ 29,700
Tablets	25	\$ 795	\$ 19,875
Total Material costs	\$ 1,219,110.00		
Labor costs	\$ 1,562,644.00		
Requested Expense	\$ 2,781,754.00		
Difference	\$ -		
TOTAL RECOMMENDED ADJUSTMENT	\$ -		

5

6

Table 2: Digital Worker Experience (2024)

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2024			
Device Type	Count	Avg. cost per device	Amount
Laptop	903	\$ 1,760	\$ 1,589,280
Desktop	82	\$ 1,115	\$ 91,430
Monitor	82	\$ 180	\$ 14,760
Tablets	17	\$ 1,150	\$ 19,550
Docking station, camera, mouse, headsets, dual monitor config.	All	\$ 251,095	\$ 251,095
MDTs	175	3774	\$ 660,399
Total Material costs	\$ 2,626,514		
Labor costs	\$ 2,394,681		
Requested Expense	\$ 5,021,195		
Difference	\$ -		
TOTAL RECOMMENDED ADJUSTMENT	\$ -		

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Table 3: Digital Worker Experience (2025)

2025			
Device Type	Count	Avg. cost per device	Amount
Laptop	676	\$ 1,890	\$ 1,277,640
Desktop	114	\$ 1,130	\$ 128,820
Monitor	63	\$ 200	\$ 12,600
Tablets	17	\$ 1,250	\$ 21,250
Docking station, camera, mouse, headsets, dual monitor config.	All	\$ 410,000	\$ 410,000
Total Material costs	\$ 1,850,310.00		
Labor costs	\$ 799,690.00		
Requested Expense	\$ 2,650,000.00		
Difference	\$ -		
TOTAL RECOMMENDED ADJUSTMENT	\$ -		

Table 4: Digital Worker Experience (2026)

2026			
Device Type	Count	Avg. cost per device	Amount
Laptop	380	\$ 2,010	\$ 763,800
Desktop	38	\$ 1,145	\$ 43,510
Monitor	21	\$ 220	\$ 4,620
Tablets	15	\$ 1,300	\$ 19,500
Docking station, camera, mouse, headsets, dual monitor config.	All	\$ 250,000	\$ 250,000
Total Material costs	\$ 1,081,430.00		
Labor costs	\$ 539,639.00		
Requested Expense	\$ 1,621,069.00		
Difference	\$ -		
TOTAL RECOMMENDED ADJUSTMENT	\$ -		

When these labor costs are added, the total project expenses align precisely with the amounts reported in U-21860 Exhibit A-24 Schedule N3, lines 241 through 244.

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1 Accordingly, the recommended disallowance of \$6.386 million by Staff Witness
2 Rogers concerning the Digital Worker Experience EOL project, as found in
3 Exhibits S-12.11 and S-12.1, should be rejected.

4

5 **Q20. Should the Commission accept Staff Witness Rogers' recommendation of**
6 **proposed disallowance of \$6.386 million by Staff Witness Rogers concerning**
7 **the Digital Worker Experience EOL project?**

8 A20. No, the Commission should not adopt Staff's proposed disallowance. Staff Witness
9 Rogers has relied solely on the material costs provided by the Company,
10 specifically focusing on equipment costs while not including the necessary labor
11 costs associated with configuration, deployment, and testing. Based on this
12 approach, she has recommended disallowances of costs related to IT investments
13 that exclude these labor components, which is similar to positions taken by Staff in
14 prior cases. Notably, the Commission rejected Staff's proposed disallowance of the
15 Digital Worker Experience EOL project in Case No. U-21534 and approved
16 recovery of the project, including labor costs.¹⁰ Additionally, in its final order in
17 Case No. U-21534, the Commission approved Digital Worker Experience EOL
18 project expenditures of \$2.885 million for 2023, \$2.488 million for 2024, and
19 \$2.404 million for 2025.¹¹¹² The Company incurred these approved expenditures
20 pursuant to, and in reliance of, the Commission's order. Thus, any disallowance in
21 this proceeding of the previously approved and spent expenditures would in effect
22 reverse a prior Commission approval after the fact. Accordingly, given both the
23 incomplete calculations underlying Staff's position and the Commission's prior

¹⁰ Case No. U-21534, Commission Order dated January 23, 2025, p. 187.

¹¹ Case No. U-21534 Staff Initial Brief pp 53-54 (disallowance).

¹² Case No. U-21534 Company Witness Sharma Exhibit A-12, Sch B5.7.7, line 18 (requested)

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1 approval in Case No. U-21534, the Commission should reject Staff's
2 recommendation.

3

4 **Q21. Please summarize Staff Witness Rogers' proposed disallowance for Corporate**
5 **Instance – Maximo Application Suite Upgrade.**

6 A21. Staff Witness Rogers recommends a \$1.411 million disallowance in the 2026 test
7 year because she believes the project is unsupported by the Company in testimony.
8 In DTE Electric's previous rate case, Case No. U-21534, the Company projected a
9 \$3.749 million investment for the Corporate Instance - Maximo Application Suite
10 Upgrade project in 2025. My direct testimony in the instant case references a
11 variance of \$3 million due to the deferral of the project into 2026 on page 134, lines
12 4-7. However, the Company's request of \$8.160 million in the instant case
13 calculates to more than a \$3 million variance. The Company's projected capital
14 expense from Case No. U-21534 and the additional \$3 million for deferral equates
15 to \$6.749 million, with a remaining \$1.411 million. Staff suggests that this
16 remaining \$1.411 million be disallowed¹³.
17

18 **Q22. Do you agree with Staff Witness Rogers' proposed disallowance for the**
19 **Corporate Instance – Maximo Application Suite Upgrade?**

20 A22. No, I do not agree with Staff's proposed disallowance. In Case No. U-21534, the
21 Company projected a need of \$3.749 million for the Corporate Maximo project in
22 2025, of which only \$3 million was approved by the Commission, resulting in a
23 \$749,000 shortfall. The variance analysis presented in my direct testimony on page
24 134, lines 4-7 compares the approved project spend for the years 2023 through 2025

¹³ Staff Witness Rogers pp. 19-21.

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1 in Case No. U-21534 with the spend for those same years in the current case. This
2 analysis does not include 2026, as that year falls outside the scope of the U-21534
3 case period and is instead addressed exclusively within Case No. U-21860.

4
5 When the 2026 investment needs are combined with the previously deferred
6 amount of \$3.749 million, the total funding requirement for the project rises to
7 \$8.160 million in 2026 not \$6.749 million as referenced in Staff Witness Rogers'
8 testimony and shown in Table 5 below.

9
10 **Table 5: Corporate Instance – Maximo Application Suite Upgrade**

	2025 Projected Spend (\$M)	2026 Projected Spend (\$M)	Approved Spend (\$M)	Disallowance (\$M)	Variance (\$M)
U-21534	3.749	N/A	2.999	0.750	2.999
U-21860 (including deferral from U-21534)		3.749 (2025 Deferred scope) +4.411(planned scope for 2026) = 8.160 (Total)			

11
12 Therefore, the recommended adjustment of \$1.411 million for the Corporate
13 Instance – Maximo Application Suite Upgrade should be rejected as it is based on
14 an inaccurate and incomplete financial assessment.

15
16 **Q23. Please summarize Staff Witness Rogers' proposed disallowance for the Field
17 Worker Device EOL project.**

18 A23. Staff Witness Rogers recommends a \$0.135 million disallowance in the 2026 test
19 year for the Field Worker Device EOL project¹⁴. She asserts that the Company
20 projects identical costs for 2024–2026, yet the number of MDTs to be replaced

¹⁴ Staff Witness Rogers, pp. 29-30.

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1 declines each year. In her testimony, Staff Witness Rogers states that audit findings
2 show the Company bases costs on the number of field worker devices replaced,
3 with \$0.9 million actually spent in 2024 on 165 devices. This equates to about
4 \$5,467 per device. At this rate, replacing 155 devices in 2025 would cost \$0.847
5 million (6% less than projected), and 140 devices in 2026 would cost \$0.765 million
6 (15% less than projected).

7

8 **Q24. Do you agree with Staff Witness Rogers' proposed disallowance for the Field**
9 **Worker Device EOL project?**

10 A24. No, I do not agree with the recommended disallowance. The Company provided
11 the number of equipment replacements in response to Staff Audit Request DR-3.4,
12 which is Staff's Exhibit S-12.11, p. 7. Table 6 below includes the information
13 provided in Exhibit S-12.11, p. 7, along with a yearly breakdown of material cost
14 per unit, labor cost per unit, and software cost, which together make up the total
15 cost.

16 **Table 6: Field Worker Device EOL**

Year	Material Cost per unit	Labor cost per unit	Software (Operating system)	Total Device Count	Total Cost
2024	\$ 4,319.75	\$ 1,048.00	\$ 16,433.00	165	\$ 902,112.00
2025	\$ 4,591.43	\$ 1,109.00	\$ 16,433.00	155	\$ 900,000.00
2026	\$ 5,087.19	\$ 1,224.00	\$ 16,433.00	140	\$ 900,000.00

17

18 Notably, Staff has applied per-unit costs only for 2024 and used fixed costs for
19 equipment in 2025 and 2026. However, the Company's cost projections reflect
20 anticipated increases in labor and equipment expenses over time, which Staff's
21 calculations overlook. The Company's cost projections for equipment replacement
22 reflect a comprehensive approach that includes not only the price of the devices but
23 also associated costs such as labor for configuration, deployment, testing, and

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1 integration. These projections factor in changes in market prices, expected usage,
2 and operational complexities over time. Unlike a simple per-unit cost calculation,
3 replacement costs consider fixed and variable components, ongoing maintenance,
4 and the realistic operational lifecycle of the assets. This ensures that the budgeted
5 costs are prudent, accurate, and reflective of actual expected expenditure rather than
6 arbitrary averages. Therefore, the recommended adjustment of \$0.135 million for
7 Field Worker Device EOL project by Staff Witness Rogers in Exhibit S-12.1 should
8 be rejected.

9

10 **Q25. Please summarize Staff Witness Rogers' proposed disallowance for the Fermi**
11 **2 Maximo Engineering Process Automation.**

12 A25. Staff Witness Rogers recommends a disallowance of \$2.552 million in the 2024
13 bridge year for this investment based on her assertion that it represents an
14 unnecessary and imprudent use of funds.¹⁵ Witness Rogers testifies that the
15 Company reported \$4.2 million in spending above the amount approved in Case
16 No. U-21534, with \$1.1 million from Staff's cost adjustments and \$3.1 million from
17 expanding the I2R Replacement scope and reallocating costs to 2023–2024. She
18 asserts that while the Company claimed this shift would expedite delivery and
19 lower costs, no quantifiable savings exist. Witness Rogers asserts that advancing
20 the project by one year was unnecessary and imprudent, and that the \$2.552 million
21 spent without measurable benefits is unreasonable to charge to ratepayers.

22

23

¹⁵ Staff Witness Rogers, pp. 21-23.

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1 **Q26. Do you agree with Staff Witness Rogers' proposed disallowance for the Fermi**
2 **2 Maximo Engineering Process Automation?**

3 A26. No, I do not agree with the recommended disallowance. The Maximo Engineering
4 Process Automation project is a reasonable and prudent investment, as it establishes
5 a dedicated Fermi-specific Maximo instance that fundamentally enhances
6 Engineering and Work Management processes. This initiative forms the critical
7 foundation for implementing Electronic Work Packages (eWP), which will replace
8 the existing paper-based work package system, leading to significant, measurable
9 benefits. The Fermi 2 Maximo Engineering Process Automation was implemented
10 to enhance operating and human performance safety margins at the Fermi 2 Power
11 Plant. Company Witness Davis, in his direct testimony, discusses the significance
12 of maintaining nuclear safety as a priority. My direct revised testimony describes
13 how the Fermi 2 Maximo Engineering Process Automation System aligns with
14 DTE Electric's nuclear safety objectives by streamlining engineering and work
15 management systems and outlines potential operational improvements as the Fermi
16 2 Power Plant moves toward electronic work packages.

17

18 **Q27. Please explain in additional detail your response to Staff Witness Rogers'**
19 **recommended disallowance.**

20 A27. Staff Witness Rogers appears to have based her recommendation to adjust the
21 Fermi 2 Maximo Engineering Process Automation project expenditures by \$2.6
22 million on a possible conflation of two distinct concepts of 'cost savings.'
23 My direct revised testimony on page 143, line 20 describes the \$2.6 million as
24 "aimed not only at expediting project delivery but also achieving cost savings." The
25 term 'cost savings' within the context of my direct revised testimony was meant to

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1 convey a reduction in total project costs associated with combining the project with
2 the I2R project. Staff, in an audit question, asked about "anticipated cost savings
3 per year for this project" (Staff Exhibit S-12.11, page 2) where the term 'cost
4 savings' was read as operational cost savings or sustainable reductions in nuclear
5 operations expenses - which is not DTE Electric's basis for the expedited
6 completion of the project.

7

8 **Q28. Should the Commission adopt Staff Witness Rogers' proposed adjustment of**
9 **the Fermi 2 Maximo Engineering Process Automation project of \$2.6 million**
10 **for the 12-month bridge period ending December 31, 2024?**

11 A28. No, the Commission should reject Staff Witness Rogers' proposed adjustment. The
12 Fermi 2 Maximo Engineering Process Automation project supports DTE Electric's
13 nuclear safety objectives by modernizing engineering and work management
14 systems as Fermi 2 transitions to electronic work packages. Disallowing this
15 investment would inappropriately discount these strategic benefits for the Company
16 and its customers.

17

18 **Q29. Please summarize Staff Witness Rogers' proposed disallowance for Backup**
19 **Environmental Growth.**

20 A29. Staff Witness Rogers testifies that \$1 million in 2025 capital costs and \$0.1 million
21 in 2026 should be disallowed.¹⁶ She asserts that in Case Nos. U-21297 and U-21534,
22 the Company projected higher costs than it actually incurred—for instance, \$0.5
23 million projected in 2022 resulted in \$0.201 million spent, and \$0.507 million
24 projected in 2023 was reduced to \$85,000. She notes that the 2024 projection has

¹⁶ Staff Witness Rogers, pp. 23-24.

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1 also been lowered to \$0.498 million, or 80% of the original estimate. Because actual
2 spending has previously fallen short, she recommends reducing 2025 and 2026
3 capital expenditures by 20%, or \$0.1 million each year.

4

5 **Q30. Do you agree with Staff Witness Rogers' proposed disallowance for Backup**
6 **Environmental Growth?**

7 A30. No, I do not agree with Staff Witness Rogers' recommended disallowance. In the
8 instant case, the target for 2025 was adjusted to \$0.5 million, consistent with the
9 prior year's actual expenditures, and the Company is on track to meet this target for
10 the Backup Environment Growth project.

11 To date, \$0.357 million has been committed this year, covering non-labor costs
12 such as software licensing, hardware upgrades, and infrastructure improvements
13 aimed at enhancing recovery speed and security, along with associated labor costs.
14 The remaining \$0.143 million (\$0.026 million non-labor and \$0.117 million labor)
15 will be directed toward continuing migration efforts, including configuration,
16 testing, and deployment activities.

17 Looking ahead to 2026, the full requested recovery amount will be utilized to
18 complete the remaining phases, including migrating Avamar filesystem backups
19 and transitioning from Dell Networker to Power Protect Data Manager (PPDM).
20 This move will strengthen data security and backup resilience. It is important to
21 note that any delays in execution could prolong reliance on unsupported tools,
22 resulting in operational inefficiencies and increased security risks. Timely
23 completion is critical to maintaining a secure and resilient backup environment.

24 This cost structure reflects a prudent allocation between labor and non-labor
25 components, covering project management, technical labor, software and hardware

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1 costs, and essential migration activities. Staff's proposed disallowance overlooks
2 these details and the ongoing nature of the work, leading to an incomplete
3 assessment.

4 Therefore, the recommended adjustment of \$0.2 million for project Backup
5 Environmental Growth by Staff Witness Rogers in Exhibit S-12.1 should be
6 rejected.

7

8 **Q31. Please summarize Staff Witness Rogers' proposed disallowance for Network**
9 **Hardening & Operations?**

10 A31. Staff Witness Rogers recommends disallowing \$0.5 million in the projected 2026
11 test year. She testifies that the Network Hardening and Operations project has the
12 same scope in 2024, 2025, and 2026, yet the Company projects costs to be \$0.5
13 million higher in 2026. In her testimony, she states that in response to a Staff audit
14 request marked as Staff Exhibit S-12.11, p. 3, the Company reported that in 2023 it
15 completed LAN redundancy at 10 sites, Power redundancy at 15 sites, and WAN
16 redundancy at two sites.¹⁷ For 2024 and 2025, it planned network robustness efforts
17 at 11 and 9 sites respectively, with costs differing by only \$3,000. She states that
18 the 2026 plan includes the same scope of work, plus VOIP upgrades at unspecified
19 "critical sites." Staff Witness Rogers asserts that, because the scope is unchanged
20 and the number of critical sites has not been identified, the projected cost increase
21 is unwarranted and the use of the additional funds is uncertain.

22

23 **Q32. Do you agree with Staff Witness Rogers' recommended disallowance for the**
24 **Network Hardening and Operations project?**

¹⁷ Staff Witness Rogers, pp. 25-26.

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1 A32. No, I do not agree. Staff proposed a \$0.5 million disallowance for the 2026 test year
2 based on the assertion that the project scope remains the same while costs increase.
3 Staff Witness Rogers' assumption that the scope remains unchanged from prior
4 years is not correct.

5 While the investments in 2024 and 2025 were approximately \$0.4 million, the 2026
6 investment of \$0.9 million reflects a substantial expansion in scope, which is driven
7 by additional robustness and redundancy enhancements at three critical sites
8 supporting Fermi 2.

9 Fermi 2 has experienced multiple large-scale outages over the past year due to
10 environmental and other issues, impacting network communication at these sites.

11 As operations become increasingly reliant on real-time data and digital control
12 systems, network reliability is essential for maintaining uptime, safety, and
13 regulatory compliance. A lack of redundancy in the current network design has led
14 to disruptions in monitoring, communications, and automated systems.
15 Implementing network redundancy, such as dual paths, failover protocols, and out-
16 of-band management, will significantly reduce downtime risk and improve
17 operational resilience.

18 • **Robustness**

19 ○ **Nuclear Operations Center (NOC) Building (300K)**

- 20 ■ Full LAN redundancy with multiple paths to COM and OSB
21 in the NOC building to prevent single points of failure,
22 addressing issues experienced in late 2024.
23 ■ Replacement of core switches and LAN switches for
24 multiple and dual path connections.

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- 1 ▪ Replacement of access points to support redundant wireless
- 2 LAN controllers.
- 3 ▪ Cabling upgrades to support newer connectivity standards (1
- 4 Gb/s and Power over Ethernet).
- 5 ○ **Auxiliary Improvement Building (AIB) and General Training**
- 6 **& Orientation Center (GTOC) (\$200K)**
- 7 ▪ Replacement of core switches and LAN switches for
- 8 redundancy.
- 9 ▪ Access point upgrades for redundant wireless support.
- 10 ▪ Similar hardware replacements as AIB building to build
- 11 redundancy.
- 12 ▪ Labor costs to implement these hardware upgrades.

13 These activities collectively address the increasing need for network stability and
14 resilience by mitigating single points of failure and supporting essential
15 infrastructure for critical communications.

16 Staff Witness Rogers' argument fails to recognize the complexity and specificity
17 of the 2026 planned activities described above, which exceed the work done in 2024
18 and 2025. The increase in costs results from essential investments in redundancy
19 and security, which are necessary to minimize downtime and operational risks for
20 the expanded scope of the Fermi sites. As such, the disallowance proposed by Staff
21 Witness Rogers should be rejected.

22

23 **Q33. Please summarize Staff Witness Rogers' proposed disallowance for the DO**
24 **Productivity Center project.**

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1 A33. Staff Witness Rogers recommends a full disallowance of the \$0.439 million
2 projected capital cost for the DO Productivity Center project.¹⁸ She testifies that
3 the DO Productivity Center is not a prudent investment, describing it as a “nice-to-
4 have” rather than a necessity. Staff Witness Rogers asserts that the Company did
5 not provide evidence of improved safety, reliability, or measurable customer
6 savings. She notes the project received a low Project Prioritization Score of 2.294
7 out of 9, indicating only minimal alignment with Company priorities and limited
8 impact across evaluation categories. Staff Witness Rogers further points out that
9 the project was implemented in 2024 without being included in Case No. U-21534,
10 raising questions about its urgency and low PPS score. She concludes that
11 ratepayers should not bear the cost of an investment that offers no clear benefits.

12

13 **Q34. Do you agree with Staff Witness Rogers’ proposed disallowance for the DO**
14 **Productivity Center project?**

15 A34. No, I do not agree with Staff Witness Rogers’ recommendation for a full
16 disallowance of \$0.439 million in the 2024 bridge period. Staff’s recommendation
17 to disallow the Company’s request for the DO Productivity Center should be
18 rejected. This project is a prudent and essential investment that enhances
19 operational efficiency, safety, and reliability, directly benefiting customers.
20 Specifically, the DO Productivity Center improves utility performance in ways that
21 positively impact service quality and reliability. It equips field crews with a
22 Situational Awareness Dashboard that centralizes real-time data, identifies
23 operational inefficiencies, and supports standardized process improvements. This

¹⁸ Staff Witness Rogers, pp. 30-32.

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1 leads to faster restoration times, reduced rework, and enhanced safety, all of which,
2 improve the customer experience.

3 Moreover, the Performance Center provides a comprehensive and accurate view of
4 productivity and work execution across operations, addressing critical process and
5 data gaps that limit visibility and efficiency improvements today.

6 Staff's characterization of this investment as "nice to have" or without benefit to
7 our customers is unfounded. For these reasons, the Commission should deny Staff's
8 proposed disallowance.

9

10 **Staff Witness Zichi's Individual IT Project Disallowances:**

11 **Q35. Please summarize Staff Witness Zichi's proposed disallowance for the**
12 **Communication Compliance and Data Loss Prevention (DLP) Diversification**
13 **project.**

14 **A35.** Staff Witness Zichi recommends a full disallowance of the Communication
15 Compliance and Data Loss Prevention (DLP) Diversification project.¹⁹ In her
16 testimony, she states "This would result in a total capital disallowance of \$186,000
17 in the 12-month bridge period ending 12/31/2025, and \$184,000 of capital and
18 \$283,000 of O&M in the test year ending 12/31/2026. (Exhibit S-12.1.) Staff
19 asserts that this adjustment is justified due to a lack of support provided by the
20 Company through audit responses.

21

22

¹⁹ Staff Witness Zichi, pp. 3-5

Line
No.

1 **Q36. Do you agree with Staff Witness Zichi's proposed disallowance for the**
2 **Communication Compliance and Data Loss Prevention Diversification**
3 **project?**

4 A36. No, I do not agree with the proposed total capital disallowance of \$186,000 in the
5 12-month bridge period ending December 31, 2025 and \$184,000 of capital and
6 \$283,000 of O&M in the test year ending December 31, 2026 for this project. As
7 stated in the Company's audit responses to EZ-1.3, which are part of Staff Exhibit
8 S-18.0, the Company is not replacing existing systems but expanding coverage to
9 enhance protection and compliance across newer platforms.²⁰ The existing solution
10 is configured to cover internal and on-premise applications, and this project will
11 extend the communication compliance capabilities to cloud applications such as
12 outbound emails, Teams, message chats, one Drive, SharePoint, Copilot and
13 channel communications.
14 The Company's operational environment has advanced rapidly over the last 12 to
15 18 months. We have introduced new communication and data-sharing capabilities,
16 expanded engagement with external partners, adopted new tools that access
17 enterprise data, broadened AI integration, and launched initiatives using emerging
18 communication channels. Our current security barriers do not fully address this new
19 landscape. To uphold the Company's security posture and protect its operational
20 environment, it is essential to implement Microsoft Communication Compliance
21 and Data Loss Prevention across all platforms, including email, Teams, Viva
22 Engage, SharePoint, and OneDrive, in order to prevent sensitive data exposure and
23 ensure regulatory compliance.
24 This Investment supports:

²⁰ Staff Witness Zichi, Exhibit S-18.0, pp. 1-3.

Line
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- 1 • **Documented risk exposure:** Unmonitored communications and data leakage
2 pose quantifiable financial and reputational risks, with potential incident costs
3 exceeding \$5 million.
- 4 • **Operational necessity:** These tools are required to maintain compliance across
5 collaborative platforms and prevent violations that could trigger regulatory
6 penalties.
- 7 • **Strategic alignment:** Our implementation roadmap is phased, measurable, and
8 directly tied to enterprise risk reduction and regulatory adherence.
- 9 • **Data Loss Prevention (DLP):** Prevents unauthorized sharing of sensitive data
10 (e.g., PCI, PII, financial records) across email, Teams, SharePoint, and OneDrive.
- 11 • **Communication Compliance:** Monitors and remediates inappropriate or non-
12 compliant communications (e.g., harassment, threats, regulatory violations).
- 13 Therefore, consistent with the Company's demonstrated need and prudent
14 planning, the recommended disallowance should be rejected.

15

16 **Staff Witness Klocke's IT Project Capital Disallowances**

17 **Q37. Please summarize Staff Witness Klocke's proposed full disallowance of the**
18 **Customer Insight Platform Application Health project.**

19 A37. On page 6, line 14-16 of her direct testimony, Staff Witness Klocke's proposal for
20 the full disallowance of \$4.275 million in capital and \$0.100 million in O&M spend
21 for the projected test year ending December 31, 2026 is based on her conclusion
22 that previously approved Customer Insight Platform Application Health
23 investments in Case No. U-21534, which Staff Witness Klocke correctly identifies
24 as the Powerley Customer Platform Application Health project, did not achieve the

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1 Company's stated goals of "increased customer participation and usage of the DTE
2 Insight App and Energy Bridges (EBs)."

3

4 **Q38. Do you agree with Staff Witness Klocke's recommendation to fully disallow**
5 **the individual project costs for Customer Insight Platform Application**
6 **Health?**

7 A38. No, I do not agree with Staff Witness Klocke's proposed full disallowance of
8 \$4.275 million in capital and \$0.100 million in O&M spend for test year ending
9 December 31, 2026. Further explained below, the Company has continued to see
10 an increase in usage of the Insight App since 2023 and justification for recovery of
11 the capital investment in Case No. U-21534 was not based solely on increasing
12 customer usage. In both Company Witness Farrell's and Sharma's testimonies in
13 Case No. U-21534, other customer benefits such as improving customer
14 experience, funding ongoing app maintenance and upgrades, software licensing,
15 and customer support as well as making minor enhancements to the Bill
16 Management Tool were all included as support in the recovery request. Hence, the
17 capital for this project should not be disallowed.

18

19 **Q39. Has the Company seen increased customer participation and usage of the DTE**
20 **Insight App and Energy Bridges in contrast to Staff Witness Klocke's**
21 **testimony?**

22 A39. Yes. Although Staff Witness Klocke correctly observed that the monthly customer
23 usage represents 2.17% of the Company's electric customer base,²¹ customer
24 downloads increased substantially from 343,461²² in 2023 to 440,000 in 2025, as

²¹ Staff Witness Klocke, p. 5

²² U-21534 Company Witness Farrell Table 5

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1 reflected in my response to Staff audit question BMK-6.1c that is part of Staff
2 Exhibit S-17.3. This is an increase of 96,539 customers and a 4.20% increase in the
3 Company's electric customer base²³ to 19.1%. Furthermore, while the Company
4 acknowledges its desire to continue to increase customer adoption and engagement
5 in the use of the DTE Insight App and EBs, its primary justification for the approved
6 investments, as described in Company Witness Farrell's direct testimony in Case
7 No. U-21534, page KOF-51, lines 7-13, was to enhance the customer experience
8 and fund ongoing app maintenance, software licensing, and customer support for
9 existing and future users of the Insight App and EBs. Similarly, Company Witness
10 Sharma's direct testimony in Case No. U-21534, further indicated that the approved
11 investments in the systems that make up the Powerley Customer Platform (now
12 known as Customer Insight Platform Application Health) would fund ongoing
13 maintenance and upgrades to support new mobile operating systems and
14 enhancements to the Bill Management tool, including various new features to help
15 customers better understand their usage, rates, and their current bill forecasts²⁴.

16

17 Regarding the instant case, as stated in my direct revised testimony, page SBA-159,
18 lines 1-4, "The Powerley Portal will support customer management, energy usage
19 visualization, bill impact information, content management, budget/rate calculator,
20 and Demand Response capabilities." These attributes support the DTE Insight App,
21 EBs, and the Bill Management web-based tools utilized by customers on
22 dteenergy.com and by Contact Resolution Specialists (CRS) for high bill calls, with
23 these customer-facing systems described in further detail in my response to audit
24 question BMK-6.1a that is part of Staff Exhibit S-17.1.

²³ <https://www.dteenergy.com/us/en/residential/about-dte/about-dte/about-dte.html>

²⁴ U-21534 Company Witness Sharma, pp 47-48

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1 **Q40. What are the customer benefits of the Bill Management tool?**

2 A40. As referenced above, the investments in the systems that make up the Customer
3 Insight Platform Application Health, approved in Case No. U-21534 under the
4 Powerley Customer Platform, fund ongoing maintenance and upgrades to support
5 new mobile operating systems and enhancements to the Bill Management tool. The
6 Bill Management tool is a Web-based tool that provides customers with the ability
7 to self-serve their billing needs. The tool provides customers with the ability to:

- 8 • Compare current usage to the previous month and provide an estimate of
9 next month's bill.
- 10 • Provide a high-level view of what are the contributors to the bill such as
11 heating/cooling and laundry.
- 12 • Compare available rate options for estimated cost savings, empowering
13 them to pick the most cost-effective option.
- 14 • Learn how changes in their home, such as energy habits or appliance usage,
15 can affect their bill, using the Bill Simulator to visualize potential impacts
16 and savings.

17 When surveyed, 55% of customers indicated they were less likely to call the
18 Contact Center to speak to a CRS after using the online tool.

19

20 **Q41. Have customers engaged in the use of the Bill Management tools?**

21 A41. Yes. See Table 7 below for year-over-year user information.

22

23 **Table 7: Bill Management Tool User and Usage Information by Year**

Year	Unique Users	Total Usage	Cumulative Usage
2022	197,315	310,765	310,765

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2023	252,745	553,588	864,353
2024	244,121	542,179	1,406,352
2025*	192,699	372,717	1,779,249

1 *2025 numbers reflected are year-to-date as of August 24, 2025.

2

3 **Q42. Is the Company evaluating the use of any other tools related to usage**
4 **management under the Customer Insight Platform Application Health?**

5 A42. To improve the experience of customers and CRS when serving customers, a new
6 tool, BillWise AI, was piloted from February 1, 2025 through August 31, 2025. The
7 tool on dteenergy.com was utilized by 49,000 customers with a 34% repeat user
8 rate (same customer returned to the tool 1 or more times during the pilot). The
9 Contact Center had 50 CRS pilot the tool for high bill calls. The BillWise AI tool
10 is the next level of digital billing customer experience by helping customers address
11 the question “why” is their bill high. Customers using the tool receive enhanced
12 customer service with clear AI-driven insights into their energy bills to understand
13 billing changes and explore personalized recommendations to reduce energy costs.
14 The tool includes approximately 72 energy saving tips, and the number continues
15 to grow. Equipped with this information, customers can make faster decisions to
16 improve their energy management.

17

18 The AI tool provides the customers with the ability to toggle between dollar
19 amounts and usage views for a clearer understanding of their bills through
20 interactive bill views. Customers can view how their energy consumption compares
21 to past usage and similar homes in their area.

22

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1 The AI tool addresses the challenges experienced by CRS by providing improved
2 efficiency and effectiveness when serving customers. A new integrated dashboard
3 reduces the need for multiple tools, streamlines workflows, reduces handling time
4 and improves customer support quality. The dashboard's integration into the SAP
5 environment provides the CRS with seamless, single sign-on access. This
6 integration also provides CRS, and customers, access to real-time customer account
7 data and information. The AI tool addresses high bill and other high-volume
8 customer concerns that include BudgetWise Billing (BWB), usage inquiries, and
9 bill history, thus empowers customers with more information about their bill and
10 reduces customer frustration.

11

12 **Q43. What would happen if funding is not approved and made available for the**
13 **Customer Insight Platform Application Health project?**

14 A43. The on-going maintenance activities are critical to the continuity, sustainability,
15 and reliability of the BillWise AI tool, Bill Management tool, DTE Insight App,
16 and Energy Bridge. Without sustainment funding, the BillWise AI tool will not get
17 released to the broader customer population. The Bill Management tool would
18 become unstable and unreliable causing the customer to lose their ability to self-
19 serve and drive them to call the Contact Center. The DTE Insight App will also
20 become unstable and unreliable. The Energy Bridge tools would lose their licensing
21 and could no longer be used by the customers that continue to use it. In short, the
22 investments the Company has made in these tools, and that customers have begun
23 to rely on, will be rendered less useful or worse and any operational efficiencies the
24 Company has achieved, such as lower call volume to CRS, will be at risk.

25

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1 In summary, for the reasons stated above, the Company recommends that the
2 Commission reject Staff Witness Klocke's proposed full disallowance of the
3 Customer Insight Platform Application Health project.

4

5 **Q44. Please summarize Staff Witness Klocke's proposed full disallowance of the**
6 **individual project costs for the Customer Relationship and Billing (CR&B)**
7 **Program.**

8 A44. On page 6, line 19 through page 9, line 2 of her direct testimony, Staff Witness
9 Klocke recommends a full disallowance of the \$6.310 million capital and \$2.695
10 million in O&M spend related to the CR&B program for the projected test year
11 ending December 31, 2026. Staff Witness Klocke expresses reservations about the
12 necessity and cost of the CR&B program. She asserts that the Company did not
13 fully explain the requested costs for the CR&B program. Further, she claims that
14 the Values/Benefits provided in Company Exhibit A-24, Schedule N3 associated
15 with the CR&B program are nebulous and do not lend Staff confidence regarding
16 the necessity of the project's costs.

17

18 **Q45. Do you agree with Staff Witness Klocke's recommendation to fully disallow**
19 **the individual project costs for the CR&B Program?**

20 A45. No, I do not agree with Staff Witness Klocke's proposed full disallowance of the
21 individual project costs for the CR&B Program for the projected test year. As
22 emphasized on page SBA-160, lines 15-21, of my direct revised testimony, the
23 CR&B Program includes critical assets which require regular maintenance to
24 "ensure the health, compliance, and strategic alignment with accurate data to meet
25 the business needs of the Customer Service, Billing and Metering, Distribution

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1 Operations, Energy Optimization, Treasury, Controller, Gas Operations, and
2 Electric and Gas Sales and Marketing organizations”. As further explained below,
3 the CR&B project provides customer benefits through 1) integration and
4 streamlining processes and applications across four application health projects, 2)
5 maintenance of the CR&B system to reduce system downtime and the inability to
6 serve customers, as well as 3) the management of system defects that reduce the
7 accessibility or performance of the CR&B system and make minor enhancements
8 to ensure the system stays up-to-date with current business processes and to sustain
9 or improve customer transaction metrics.

10
11 Additionally, in my direct revised testimony on page SBA-161, lines 2-13, in
12 alignment with the Company’s strategic vision of cost optimization, the scope and
13 associated costs of the Automated Application Monitoring Health, Closed Loop
14 COCL Application Health, Customer Information Technology Configuration
15 Management and Customer Legacy Application Health projects were integrated
16 into the CR&B Program. The integration streamlined the Company’s processes,
17 enhanced operational efficiency, and ensures a more cohesive approach to
18 managing customer relationships and the billing program. The consolidation of
19 these elements is intended to improve service delivery, cost management, and
20 alignment with the Company’s long-term goals. A detailed description of the
21 functionality and capabilities provided by each project is set forth in Exhibit A-24,
22 Schedule N1, page 470 and 475.

Line
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1 **Q46. Do you agree with Staff Witness Klocke’s testimony that the Value/Benefit of**
2 **the CR&B Program is “nebulous”?**

3 A46. No, I do not agree with Staff Witness Klocke’s assertion that the Value/Benefit of
4 the CR&B program is nebulous found in her direct testimony on page 8, lines 3-13.
5 The on-going maintenance activities being funded by the \$6.310 million in capital
6 and \$2.695 million in O&M are critical to the continuity, sustainability, and
7 reliability of the Customer Relationship & Billing Program. The maintenance
8 activities occur daily, monthly, and annually for system and application patches.
9 These critical activities reduce the risk of unplanned outages within the CR&B
10 platform that disrupt critical business operations and lead to customer
11 dissatisfaction.

12

13 The maintenance activities are categorized as operations or product support.
14 Operations support includes the governance of the application’s Incident
15 Management, Application Health Monitoring, Configuration Management,
16 Application Release Management, and Application and Operation System (OS)
17 Patches processes. The importance of operational support activities is stated below.

18

19 1. Incident Management and Application Support involves the prioritization
20 and resolution of IT incident tickets entered by end users. The process steps
21 include identifying, logging, analyzing, and resolving system issues.
22 Without the performance of this process, critical incidents would not be
23 prioritized leading to CR&B experiencing prolonged downtime that could
24 impact billing processes and accessing customer data.

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- 1 2. Application Health Monitoring is a tracking system for key performance
- 2 metrics such as CPU usage, memory, and response times. This process is in
- 3 place to catch system anomalies before they cause a system failure. Without
- 4 the performance of this process, system performance issues could be missed
- 5 and lead to the system being overwhelmed during peak times to create an
- 6 unplanned outage.
- 7 3. Configuration Management is the process that ensures documentation,
- 8 consistency, and alignment with operational requirements for all system
- 9 settings, parameters, and dependencies. This process prevents
- 10 misconfigurations that could destabilize the system causing an outage.
- 11 4. Application Release Management is the process that governs the
- 12 deployment of updates, bug fixes, and new features to ensure changes are
- 13 tested and rolled out systematically. This process prevents untested or
- 14 poorly managed releases introducing defects into the system that disrupt
- 15 operations.
- 16 5. Yearly Patching of OS and Application is a process that addresses security
- 17 vulnerabilities, performance issues, and compatibility problems in the
- 18 operations system and CR&B. This process prevents performance bugs that
- 19 could degrade system stability or a cyberattack corrupting CR&B data that
- 20 forces an emergency shut down for recovery.

21

22 The Product support of CR&B includes the Digital Factory Sustainment initiative
23 which ensures the customer-facing and backend processes remain effective and
24 reliable through the Defect Management and Minor Enhancement process
25 activities. The CR&B application team has developed a resiliency plan to sustain

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1 and maintain the quality standards in the areas of Move In Move Out (MIMO),
2 Collections, Billing, Payment, MPSC Compliance, Meter Installation, Service
3 Orders, Gas Leaks and Electric Outages, Web Backend Support, and Customer
4 Service Agent's Experience. The importance of product support activities is stated
5 below.

6
7 1. Defect Management is the management of imperfections or anomalies that
8 are affecting the accessibility or performance within CR&B. Each defect is
9 triaged and analyzed. Fixes are then designed, developed, tested and
10 deployed into production. Without correcting these defects, the system
11 would ultimately experience system performance issues and unplanned
12 outages, resulting in negative impact to customers.

13 2. Minor Enhancements are the incremental improvements of customer
14 transactions that keeps CR&B up to date with current business processes
15 and ensures the customer transaction metrics improve or stay on track.
16 Without performing these minor enhancements, the system would become
17 out of sync with the business processes creating inefficiencies and causing
18 team members to perform workarounds which negatively impacts metrics
19 and customer satisfaction.

20
21 **Q47. In summary, what is your recommendation regarding Staff Witness Klocke's**
22 **proposed full disallowance of the CR&B Program?**

23 A47. For the reasons stated above, I recommend that the Commission reject Staff
24 Witness Klocke's proposed full disallowance of the individual project costs for the
25 CR&B program.

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1 **Q48. Please summarize Staff Witness Klocke's proposed full disallowance of the**
2 **individual project costs for the DTE Mobile App project.**

3 A48. On page 9, line 9 through page 10, line 18 of her direct testimony, Staff Witness
4 Klocke recommends a full disallowance of the requested costs for the DTE Mobile
5 App, a total of \$1.100 million in capital and \$0.170 million in O&M costs for the
6 test year ending December 31, 2026. Staff Witness Klocke questioned the Mobile
7 App's usage rate and suggested there is nothing offered by the Mobile App that
8 customers cannot access via the Company's website. Ultimately, she does not
9 believe that the requested expenses for the Mobile App are necessary at this time.

10

11 **Q49. Do you agree with Staff Witness Klocke's recommendation to fully disallow**
12 **the individual project costs for DTE Mobile App?**

13 A49. No, I do not agree with Staff Witness Klocke's recommendation to disallow all
14 requested costs for the DTE Mobile App, a total of \$1.100 million in capital and
15 \$0.170 million in O&M costs for the test year ending December 31, 2026. I disagree
16 with her recommendation primarily because a significant portion of the Company's
17 customers engaged in the use of the Mobile App to complete their self-service
18 transactions. To support that point, I would like to clarify that the 19% Mobile App
19 usage reported in my direct revised testimony on page SBA-163, lines 16-19,
20 reflects the percentage of total interactions completed via the App, which includes
21 automated interactions, such as auto-pay or external electronic fund transfer
22 payments (e.g., Chase Bill Pay), which do not require customer engagement. When
23 automated interactions are removed, the Mobile App accounts for 25% of all self-
24 service interactions. Furthermore, 50% of outage-related transactions are
25 completed through the Mobile App. In 2024, ~818,000 or ~30% of customers have

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1 used the Mobile App at least once and on average there are 300,000 to 350,000
2 active users per month. Since 2015, the App has also been downloaded ~2 million
3 times.

4
5 Also important to note is that over the past three years, Mobile App interactions
6 have grown by 5%, a significant increase given the Mobile App's limited
7 functionality and interaction volume. While the Mobile App offers the same core
8 functionality as the Website, customers prefer different channels based on
9 convenience and comfort. The Company's goal is to meet customers where they
10 are, especially during the moments that matter the most like outages, ensuring
11 accessibility through their preferred channel.

12

13 **Q50. Do you agree with Staff Witness Klocke's position that the current requested**
14 **expenses for the Mobile App for maintenance and improved customer**
15 **experience ratings are not necessary at this time?**

16 A50. No, I do not agree. The minimal funding allocated to maintenance that Staff
17 Witness Klocke recommends to fully disallow is essential to keep the app available,
18 secure, and functional for the Company's customers. This objective involves
19 critical tasks like security updates, app upgrades, and updating business rules to
20 stay aligned with evolving business processes. For instance, this year, funding went
21 toward implementing reCAPTCHA to strengthen security after multiple cyber-
22 attacks, updating Payment API URLs due to our payment processor's configuration
23 changes and updating outage status communications to support restoration estimate
24 windows. Without these updates, our customers would not have been protected
25 from malicious actors, would not have been able to use the app for payments or

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1 would have received inconsistent outage communications across channels. We also
2 use this funding to address reported defects and bugs to ensure reliable user
3 experience. This funding is not for building new features or improving app ratings
4 but is strictly necessary to maintain core functionality and security.

5

6 **Q51. Please summarize Staff Witness Klocke's proposed full disallowance of the**
7 **individual project costs for the 2025-2026 Outage WISMO, PPS and Map**
8 **Application Health projects and 2026 Outage WISMO, PPS, and Map**
9 **Enhancement projects.²⁵**

10 A51. On page 10, line 19 through page 16, line 10 of her direct testimony, Staff Witness
11 Klocke recommends full disallowance in the following amounts: 1) for the Outage
12 WISMO, PPS and Map Application Health projects, \$3,000,000 in capital for the
13 bridge year ending December 31, 2025, as well as \$5,250,000 in capital and
14 \$249,496 in O&M costs for the test year ending December 31, 2026; and 2) for the
15 Outage WISMO, PPS, and Map Enhancement projects, \$1,700,001 in capital and
16 \$525,000 in O&M costs for the test year ending December 31, 2026. Staff Witness
17 Klocke asserts that the Company has been previously granted funding of \$50
18 million for the Error Free Communication (EFC) initiative in the two prior rate
19 cases and is asking for an additional \$10 million in funding in the instant case when
20 it has yet to demonstrate that the EFC is meeting its stated goals from previous rate
21 cases. She emphasized that she believes the requested expenditures for these
22 projects are premature as the Company has not yet proven the success of the EFC

²⁵ As acknowledged by Staff Witness Klocke, the Outage WISMO, PPS and Map Application Health and Outage WISMO, PPS, and Map Enhancement projects directly correlate to the functionality of the Company's EFC system.

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1 program. She further claims that DTE Electric has not supported its requested
2 additional spending need in testimony or audit questions.

3

4 **Q52. Do you agree with Staff Witness Klocke's recommendation to fully disallow**
5 **the individual project costs for the 2025-2026 Outage WISMO, PPS and Map**
6 **Application Health projects and 2026 Outage WISMO, PPS, and Map**
7 **Enhancement projects?**

8 A52. No, I do not. As explained in more detail below, the Company has provided
9 sufficient evidence in direct testimony and exhibits to support both projects.

10

11 First, it is important to clarify why the Company is requesting recovery of the \$10
12 million in capital for these two projects and how they differ from prior requests for
13 EFC funding in previous rate cases. \$8.3 million of the \$10 million for the Outage
14 WISMO, PPS and Map Application Health projects is entirely new and has not
15 been requested in prior rate cases. Funding for the Application Health projects is
16 being requested now that the EFC Systems have reached a state of development
17 through previously approved investments by which they can and must be sustained.

18 As described in my direct revised testimony on page SBA-166, lines 10 through 17,
19 with the implementation of the Error Free Communications – Outage Status (EFC)
20 initiative, three significant core assets, Where-is-my-Order (WISMO), Premise
21 Power Status (PPS), and the Outage Map, were developed to support the Outage
22 Management and Storm processes. These core assets need to be sustained on an
23 ongoing basis to support during Blue Sky conditions and ensure their uptime and
24 resiliency to perform during storm conditions. Sustainment of these core assets
25 ensures they are able to adapt to changes and improvements as the Company makes

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1 further progress toward the Company's long-term EFC goals and objectives. Like
2 other sustainment / application health funding that the Company is requesting for
3 recovery, this spend is non-discretionary because it is critical for ensuring that the
4 supported technology is working as intended, performing at optimal levels,
5 adapting to changes in business needs, and resilient during severe weather events.
6 I will speak more about the details of the Application Health projects below.

7

8 For the remaining \$1.7 million in requested funding for the Outage, WISMO, PPS
9 Enhancement projects, this investment will continue to move the Company toward
10 its stated long-term EFC goals and improvement in the four key EFC metrics. I will
11 also speak more about the details of the Enhancement projects and how the
12 Company has delivered against its stated goals and provided evidence to support
13 this spend.

14

15 **Q53. Staff Witness Klocke, page 14 lines 10-11 states "Nowhere, either in direct**
16 **testimony or audit questions, has the Company demonstrated the need for this**
17 **additional spend for these projects." Do you agree with this statement?**

18 A53. No, I do not agree with Staff Witness Klocke's characterization of the Company's
19 testimony and audit responses. On page SBA-166 line 4 through page SBA-167,
20 line 10, I discuss the reasons for why the 2025-2026 Outage WISMO, PPS and Map
21 Application Health projects are necessary to sustain core EFC Systems, including
22 defect remediation, minor enhancements, load testing, security, optimization of the
23 Outage Map and optimization and integration between the EFC Systems and with
24 other systems like ADMS and CR&B.

25

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1 For the 2026 Outage WISMO, PPS and Map Enhancement projects, I discuss why
2 these projects are necessary and the expected benefits in my direct revised
3 testimony on page SBA-207 through page SBA-208, which include Centralized
4 Communications with WISMO, Enhanced Tools for Customer Representatives,
5 Architecture Enhancements to WISMO and PPS Systems, and Continuous
6 Resiliency Enhancements. Additionally, in response to Staff audit question BMK-
7 6.6, page 2, which is part of Staff Exhibit S-17.14, I interpreted what was in column
8 (k) of Exhibit A-24, Schedule N3 for these projects by describing how the benefits
9 from these enhancements provide further improvement in Customer Power Status,
10 the accuracy of the data for outage communication to improve First Estimate
11 Accuracy, and the ability to refine estimates to a window versus day-of and ensure
12 accurate estimates are delivered across all customer channels consistently. A
13 detailed breakdown of the 2026 investment of \$1.7 million by EFC Customer-
14 Facing Workstream is provided on page 2 in column (d), labelled 2026 Estimated
15 of Exhibit A-24, Schedule N7.

16

17 I provide further details related to both the Application Health and Enhancement
18 projects in my next two questions.

19

20 **Q54. Why is funding for the Application Health projects necessary?**

21 A54. The Application Health projects by nature are necessary and non-discretionary.
22 The projects are structured around four key focus areas that ensure the EFC Systems
23 remain resilient, responsive, and aligned with evolving customer and business
24 needs. The requested funding supports the following activities undertaken in each
25 of the key focus areas:

Line
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- 1 1) **Resiliency:** To maintain system availability and reliability, the Company
2 conducts quarterly resiliency testing (as recommended by Liberty Audit). These
3 tests identify vulnerabilities and targeted improvement areas. Recently
4 resiliency efforts included multi-region cloud redundancy, enabling seamless
5 failover to an alternative cloud location when the primary region is unavailable
6 and decommissioning obsolete SAP interfaces that still receive traffic, reducing
7 unnecessary risk to critical systems such as to the SAP CRM system.
- 8 2) **Updating Business Rules & Communications:** As outage restoration
9 strategies and business processes evolve - such as the increased use of “restore
10 before repair” and temporary restorations - communication logic within
11 WISMO and PPS must be updated to prevent premature restoration messages
12 from being sent to customers. These updates are essential to maintaining
13 accuracy in customer communications. For example, recent changes have
14 addressed performance declines in the “Restoration Communication Accuracy”
15 metric (see Table 8, row #6 below).
- 16 3) **Continuous Improvement and Data Optimization:** Systems that process
17 large volumes of data require ongoing optimization to ensure timely and
18 efficient communication. Enhancements in data flow have directly contributed
19 to improvements in the “Restoration Communications Sent within 1-hour”
20 metric (see Table 8, row #7 below). These optimizations are part of a broader
21 commitment to data-driven performance management.
- 22 4) **Addressing Defects from Customer Feedback & Internal Reviews:** The
23 Company regularly reviews customer feedback and conducts internal
24 investigations to identify system defects and improvement opportunities. These

Line
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1 insights drive updates that enhance functionality, correct issues, and improve
2 the overall customer experience.

3

4 Funding for the Application Health projects is a critical, non-discretionary
5 investment. These systems enable critical customer communications and outage
6 management. Without ongoing funding, performance will decline, leading to
7 slower responses, inaccurate communications, and reduced customer trust.
8 Continued investment ensures stability, accuracy, and adaptability as business
9 needs evolve.

10

11

Table 8 : Outage Communications Scorecard (Non-Storm)

#	Area	Metric	WE 8/3	WE 8/10	WE 8/17	WE 8/24	Past 4 Weeks ¹	YTD Actual	YTD Target	YE Target	2024 Actual
1	Overall	AMI Customer Verified Outages	106k	57k	114k	48k	321k	1.7m	--	2.94m	2.8m
2		Percent of Customers Communicated With	57%	56%	57%	47%	56%	55%	> 58% (4WR)	> 60% (4WR)	56%
3		Customer Effort Score Percent rated Extremely Easy & Somewhat Easy	70%	72%	71%	65%	70%	73%	--	--	62%
4	Customer Power Status	AMI Meters Reporting Power Out – Pre-processing Filter	47%	51%	46%	53%	49%	51%	> 56% (4WR)	> 60% (4WR)	42%
5		AMI Outage Communication Accuracy "Our meter alerted us ..."	99%	93%	97%	98%	97%	97%	> 98%	> 98%	96%
6		Restoration Communication Accuracy "We restored power ..."	98.3%	99.5%	98.6%	99.5%	98.7%	99.1%	> 99%	> 99%	99.4%
7		Restoration Communication Sent within 1- Hour	89%	82%	85%	89%	86%	79%	> 80% (4WR)	> 80% (4WR)	60%
8	Estimates	First Estimate Accuracy ²	77%	83%	71%	84%	77%	77%	> 80%	> 80%	62%
9		Expired Estimates	< 1%	< 1%	< 1%	< 1%	< 1%	1%	0%	0%	4%

12

1. Past 4 weeks: Jul 28 – Aug 24, 2025

13

2. Estimate windows implemented 7/1/2025. Year-to-date performance reflects a combination of historical
14 estimate details (date/time) and current estimate data based on the new window format.

15

16 **Q55. Why is funding for the Enhancement projects necessary?**

17

A55. The Enhancement projects build upon the EFC capabilities that the Company has
18 put in place with the previously approved \$50 million in investment to build and

Line
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1 enhance the EFC Systems. The Enhancement projects continue to elevate the
2 outage communication experience and move the Company further toward long-
3 term EFC targets and goals by (1) supporting customers during other outage types
4 such as planned outages, (2) providing more detailed information about the causes
5 of an outage, (3) delivering personalized and improved service recovery for
6 customers who have experienced more frequent or long outages, and (4) enabling
7 CRs with tools to better serve customers during an outage and bridge any gaps in
8 outage information across customer channels. Unlike the Application Health
9 projects above, which focuses on stability, resiliency and optimization, the
10 Enhancement projects improve and expand upon the EFC System capabilities to
11 continue to enhance the customer experience. Details about these four aspects of
12 the projects are provided below.

13
14 **1) Enabling Communications for New Outage Types and Centralizing in**

15 **WISMO:** Extend EFC systems to support planned outages and follow-up
16 outage jobs, which were not addressed in the original project and continue to
17 be a point of frustration for customers.

18 **2) Improving Outage Cause Transparency:** Redesign how outage causes are
19 communicated to customers, another major pain point for customers who want
20 clear, more informative explanations, not vague reasons or generic cause codes.

21 **3) Personalizing Communications and Experience for Frequent Outage**

22 **Customers:** Develop differentiated experiences for customers impacted by
23 repeated outages by tailoring messaging and support to reflect their unique need
24 and frustrations.

Line
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1 4) **Empowering Customer Representatives (CRs):** Build internal tools that
2 enable CRs to access and communicate outage status effectively, bridging the
3 gap between digital self-serve channels and live support, which was not
4 addressed as part of the original project.

5
6 Enhancements are essential to meet increasing customer expectations. Without this
7 investment, the outage communication experience remains limited, frustrating
8 customer and supporting teams. These enhancements are the next steps in
9 delivering a modern, transparent and personalized outage experience.

10

11 **Q56. Do you agree with Staff Witness Klocke’s testimony that “the Company has**
12 **not even been shown how past expenditures were used for [the Error Free**
13 **Communication project]”²⁶?**

14 A56. No, Staff Witness Klocke’s assertion that the Company has not shown how past
15 expenditures were used for the EFC project does not take into account the
16 Company’s testimony and exhibits. Provided in this instant case is Exhibit A-24,
17 Schedule N7 Error Free Communication (EFC) Capital Investment, which
18 specifically includes the total amount of capital being invested in the EFC Core
19 System components and Customer-Facing System workstreams, as well as the total
20 capital that was previously approved for recovery by the Commission in Case Nos.
21 U-21297 and U-21534. My direct revised testimony on page SBA-196, lines 6-13
22 discusses this exhibit. Thus, contrary to Staff Witness Klocke’s assertion, the
23 Company has in fact provided specific evidence on previous expenditures for the
24 EFC project.

²⁶ Staff Witness Klocke pp 14

Line
No.

1 **Q57. Do you agree with Staff Witness Klocke’s assertion that “the Company**
2 **believes more money is needed for this project before it can prove that the EFC**
3 **is meeting its stated goals from previous rate cases”?**

4 A57. No, Staff Witness Klocke’s characterizations do not accurately reflect my
5 testimony and exhibits, which demonstrate how the EFC system is making progress
6 to the long-term goals. An in-depth discussion of the improvements made in the
7 EFC metrics for Customer Premise Power Status (PPS), Power Restoration
8 Accuracy and Timeliness, First Estimate Accuracy, and Outage Notification
9 Delivery is covered in my direct revised testimony on page SBA-197, line 4 through
10 page SBA-200, line 20. These metrics were also discussed, as noted by Witness
11 Klocke in her direct testimony on page 14, line 16 through 18, during the first of
12 two bi-annual EFC updates to the MPSC Staff. As of today’s date, there has only
13 been one meeting because these were scheduled after the final order in Case No.
14 U-21534 with the next meeting in December. The goal is to schedule the bi-annual
15 update meetings in June and December each year. During the bi-annual meeting,
16 challenges and learnings were also shared with Staff on the continuous effort to
17 improve the EFC metrics and the customer’s overall outage experience.

18
19 Additionally, I testified on the recent improvements made to the Customer-Facing
20 System Workstreams in my direct revised testimony on page SBA-201, line 14
21 through SBA-203, line 4. The improvements I discuss are in the Police & Fire
22 Portal, Down Power Line Reporting, Mobile App Outage Type-ahead Feature,
23 Picture Upload, Status First, and Outage Reporting Guidance. Exhibit A-24,
24 Schedule N8 was provided that gives screen shots of these enhancements.

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1 Thus, the Company has in fact offered evidence in the instant case that the EFC is
2 making progress to the long-term goals.

3

4 **Q58. In summary, what is your recommendation regarding Staff Witness Klocke's**
5 **proposed full disallowance of the individual project costs for the 2025-2026**
6 **Outage WISMO, PPS and Map Application Health projects and 2026 Outage**
7 **WISMO, PPS, and Map Enhancement projects?**

8 A58. For the reasons stated above and based on the Company's testimony and exhibits
9 in the instant case, the Commission should reject Staff's proposed disallowance of
10 \$10 million for these two projects. The Company has been responsible in its
11 funding requests by providing evidence of the previous expenditures, ongoing
12 improvement in the EFC metrics, and the necessity of on-going sustainment and
13 enhancement activities as we move toward long-term EFC targets and goals.

14

15 **Q59. Please summarize Staff Witness Klocke's proposed full disallowance of the**
16 **Payment Merchant Fees project.**

17 A59. On page 16, line 7 through page 18, line 5 of her direct testimony, Staff Witness
18 Klocke recommends a full disallowance of \$9.998 million in capital expenditures
19 for the bridge period ending December 31, 2025, for the Payment Merchant Fees
20 project. Staff Witness Klocke suggests that although Staff does not necessarily have
21 an issue with the merits of the Payment Merchant Fees project itself, her primary
22 concern relates to the cost of the project. She asserts that the Company did not
23 demonstrate that due diligence was done to ensure that the contractor hired will
24 develop and implement the Payment Merchant Fees project at a reasonable cost.
25 Staff Witness Klocke alleges that because the Company plans to continue

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1 recovering residential merchant fees through base rates in the instant case if the
2 costs are disallowed for this project, the Company is aware that the project may not
3 be approved by the Commission which she believes further supports a full
4 disallowance.

5

6 **Q60. Do you agree with Staff Witness Klocke's proposed full disallowance of costs**
7 **for the Payment Merchant Fees project?**

8 A60. No, I do not agree with Staff Witness Klocke's recommendation to fully disallow
9 the \$9.998 million in capital expenditures for the bridge period ending December
10 31, 2025, for the Payment Merchant Fees project.

11

12 It is important to note that the contractors engaged in this project are not new
13 vendors. They are long-standing business partners of the Company, who currently
14 support the Company's payment systems and have previously undergone thorough
15 vetting to ensure they deliver a strong balance of quality and cost-efficiency. Given
16 the complexity of migrating from our existing payment processor to a new one, to
17 enable merchant fees, it was critical to engage partners already familiar with our
18 systems. This decision reduces implementation risk, shortens ramp-up time, and
19 ensures continuity across all areas: system integration, data migration,
20 development, design, testing, and change management. The high cost reflects the
21 depth of this effort and the number of systems and partners involved in executing
22 it successfully. Each partner plays a critical role in ensuring the migration is secure,
23 compliant, and minimally disruptive to operations and customers.

24

Line
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1 **Q61. Why should the Commission reject Staff Witness Klocke's proposed**
2 **disallowance?**

3 A61. In my direct revised testimony on page SBA-211, lines 1-7, and my response to
4 audit question BMK-9.9, I explain that the contract costs are for a third-party
5 payment provider to develop the credit card fee surcharge solution that includes
6 credit card fee processing, Visa consulting support, and a seamless long-term
7 payment strategy for customers. The cost includes the design, development, and
8 testing of the payment solution across all payment platforms and CR&B. Notably,
9 the actual costs have been confirmed through executed contracts, as detailed in
10 Table 9 below, and are consistent with the \$8.00 million vendor estimate provided
11 in my audit response to BMK-9.9 which is part of Staff Exhibit S-17.12.

12

13 **Table 9 Merchant Fee Actual Costs**

	Actual Costs
Vendor Cost by System	
Website	\$1,847,883
Mobile App	\$1,674,032
IVR	\$350,000
SAP Cloud Systems	\$326,912
Agency Website	\$140,000
Kiosk	\$50,000
CR&B	\$2,279,479
Other Supporting Vendor Cost	
Strategic Consulting	\$397,823
User Experience Design	\$76,175

Line
No.

Business and Testing Support	\$706,916
Data	\$100,000
Current Payment Processor (Paymetric)	\$100,000
Total	\$8,049,219

1

2 **Q62. How has the scope and approach to the Payment Merchant Fee project**
3 **changed since the filing of this instant rate case?**

4 A62. The initial project scope planned a phased go-live, starting with passing merchant
5 fees directly to non-residential customers. The Company also intended to include a
6 feature for Residential customers, enabling fee passing based on the possibility that
7 the Commission could disallow the socialization of residential merchant fees in the
8 instant case, as they did for non-residential merchant fees in Case No. U-21534.
9 This approach was intended to balance flexibility with the immediate needs of the
10 non-residential segment.

11

12 During implementation, however, deeper analysis uncovered critical challenges
13 that led to a revised scope and approach. Enabling the fee passing feature requires
14 switching payment processors, which is a complex process involving extensive data
15 migration, development, and testing. This transition also results in significantly
16 higher costs for the Company to absorb fees if they are not passed on to customers.
17 Implementing the change separately for non-residential and residential customers
18 would duplicate efforts and costs. As reflected in Company Witness Foley's
19 rebuttal testimony, the Company is withdrawing its request for recovery of
20 residential merchant fees; hence, the Company is therefore moving forward with
21 the concurrent charging of fees to both non-residential and residential customers.

Line
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1 This streamlines the process, minimizes risks from multiple transitions, and ensures
2 a cost-effective execution. We have developed a robust change management and
3 communication plan to support our customers during this change.

4

5 **AG – Witness Coppola O&M Disallowances:**

6 **Q63. Are there any O&M expenditures recommended for disallowance by Attorney**
7 **General (AG) Witness Coppola?**

8 A63. Yes, AG Witness Coppola recommended a total of \$8.18 million in O&M
9 disallowances for the following:

- 10 • \$2.5 million of O&M adjustment for 2024 forecast for NICE software
11 implementation.
- 12 • \$5.68 million cost to achieve line item for projected test year ending
13 December 31, 2026, to support new IT projects.²⁷

14

15 **Q64. Do you agree with AG Witness Coppola’s recommendation of a full**
16 **disallowance of \$2.5 million O&M adjustment for 2024 forecast for NICE**
17 **software implementation and should the Commission accept the proposed**
18 **disallowance?**

19 A64. No, I do not agree with AG Witness Coppola’s recommended disallowance. The
20 Company did not incur the full \$2.5 million in O&M expense during 2024 since
21 the software was implemented in July of that year. As NICE software maintenance
22 costs are annually \$2.5 million, only ~\$1.0 million was realized in 2024 due to the
23 mid-year implementation. Accordingly, the Company proposes to update the
24 adjustment and requests recovery of \$1.5 million in O&M expenses as the

²⁷ Attorney General Witness Coppola pp. 134-135.

Line
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1 appropriate forecasted adjustment for 2024. The Commission should therefore
2 reject the proposed full disallowance and approve recovery for the partial
3 adjustment amount of \$1.5 million.

4

5 **Q65. Do you agree with AG Witness Coppola's recommendation of a full**
6 **disallowance of \$5.68 million cost to achieve line item for projected test year**
7 **ending December 31, 2026, to support new IT projects?**

8 A65. No, I do not agree with AG Witness Coppola's recommended disallowance. The
9 \$5.68 million projection is driven by the expected project volume and appropriately
10 aligns with the O&M Cost-to-Achieve associated with the capital investments,
11 support for which has been provided in U-21860, Exhibit A-24, Schedule N3. In
12 addition, the Company notes that this proposed disallowance by AG Witness
13 Coppola appears to result in a double counting of O&M costs already subjected to
14 disallowances proposed by Staff. For these reasons, the Commission should reject
15 the AG's proposed \$5.68 million full disallowance.

16

17 **Q66. Does this conclude your rebuttal testimony?**

18 A66. 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

REBUTTAL TESTIMONY

OF

NEAL T. FOLEY

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF NEAL T. FOLEY

Line
No.

1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed?**

3 A1. My name is Neal T. Foley (he/him/his). My business address is One Energy Plaza,
4 Detroit, Michigan 48226. I am employed by DTE Electric Company as Director of
5 Marketing.

6
7 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
8 **Company (DTE Electric or Company)?**

9 A2. Yes.
10

11 **Purpose of Testimony**

12 **Q3. What is the purpose of your rebuttal testimony?**

13 A3. The purpose of my rebuttal testimony is to respond to certain positions taken by
14 Witnesses Freeman, Krause, and McMillan-Sepkoski on behalf of Michigan Public
15 Service Commission (MPSC or Commission) Staff (Staff); Witness Schuster on
16 behalf of the Michigan Energy Innovation Business Council, Institute for Energy
17 Innovation, and Advanced Energy United (collectively “MEIU”); Witness Coppola
18 on behalf of the Attorney General (AG); and Witness Woolley on behalf of Natural
19 Resources Defense Council (“NRDC”) and Sierra Club.

20

21 I will address intervenor positions related to the following:

- 22 • The Company’s proposed Transportation Electrification Plan (TEP)
23 Regulatory Asset authorization and rebate program funding reallocation by
24 MEIU Witness Schuster and Staff Witnesses Freeman, McMillan-Sepkoski,
25 and Krause

Line
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- 1 • TEP Regulatory Asset amortization period by NRDC and Sierra Club
- 2 Witness Woolley
- 3 • TEP program improvements proposed by MEIU Witness Schuster
- 4 • The Company's Electric Vehicle (EV) forecast and Utility Make Ready
- 5 (UMR) capital investment by AG Witness Coppola and Staff Witness
- 6 Freeman
- 7 • The Company's TEP Benefit Cost Analysis (BCA) by NRDC and Sierra
- 8 Club Witness Woolley
- 9 • The Company's proposed Charging Hub capital recovery by NRDC and
- 10 Sierra Club Witness Wooley and Staff Witness Freeman
- 11 • Residential Contribution in Aid of Construction (CIAC) communications
- 12 proposed by NRDC and Sierra Club Witness Wooley
- 13 • The Company's proposed recovery of residential merchant fees by Witness
- 14 McMillan-Sepkoski
- 15 • Regulated Marketing O&M normalization adjustments by AG Witness
- 16 Coppola
- 17 • Other proposed Regulated Marketing disallowances by AG Witness
- 18 Coppola and Staff Witness McMillan-Sepkoski

19

20 **Q4. Are you sponsoring any exhibits as part of your rebuttal testimony?**

21 A4. No.

Line
No.

1 **TEP Regulatory Asset Authorization and Rebate Program Funding Reallocation**

2 **Q5. Can you summarize intervenor positions related to the Company's proposed**
3 **TEP Regulatory Asset authorization and the Company's ability to reallocate**
4 **funding between rebate programs?**

5 A5. Yes. MEIU Witness Schuster and Staff Witnesses Freeman, McMillan-Sepkoski,
6 and Krause provided testimony related to TEP Regulatory Asset authorization and
7 the Company's ability to reallocate funding between rebate programs as needed.

8

9 In their respective testimonies, Staff Witnesses Freeman and McMillan-Sepkoski
10 both support the Company's proposal to record TEP Regulatory Assets beyond the
11 forward test year in the instant case (Freeman Direct Testimony, page 6; McMillan-
12 Sepkoski Direct testimony, page 11).

13

14 However, Staff Witness Freeman does not support the Company's proposal that it
15 be allowed to reallocate funding between rebate programs, arguing:

16

17 "It is not the best option as it does not allow for proper oversight. Staff
18 recommends that DTE set a program budget and not exceed that amount. The
19 Company can then apply any learnings in its next rate case proposal to adjust
20 future programmatic budgets" (Freeman Direct Testimony, page 7, lines 3-6).

21

22 Staff Witness Krause suggests areas where the reallocation of funding could be
23 allowable, specifically identifying "any reallocation of funding that leads to more
24 off-peak charging could be considered beneficial" (Krause Direct Testimony, page
25 6, lines 4-5).

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1 Likewise, MEIU Witness Schuster expresses concerns with the Company's
2 proposal that it be allowed to shift funding between rebate programs. She argues:

3
4 "These programs and the spending levels associated with them are established
5 for a myriad of reasons in each successive general electric rate case, and to
6 allow the Company the ability to reallocate funds without guardrails,
7 stakeholder input and Commission oversight would seem to undermine that
8 formal review process" (Schuster Direct Testimony, page 66, lines 21-24).

9
10 MEIU Witness Schuster goes on to suggest a potential solution:

11
12 "...the Commission could define, through a stakeholder process, guardrails or
13 circumstances under which the Company can assess programs to determine
14 reallocation eligibility. The Company could then be granted authority to
15 reallocate funds between Commission-approved TEP programs as long as those
16 guardrails are followed. Alternatively, the Commission could require the
17 Company to file a formal request to reallocate funds, which could be done in an
18 expedited, ex parte filing, to allow stakeholders the chance to respond or object
19 if they choose to do so" (Schuster Direct Testimony, page 67, lines 2-8).

20
21 MEIU Witness Schuster additionally provides suggestions on what issues should
22 be considered if the Commission were to establish "guardrails" to the Company's
23 ability to shift funding between programs (Schuster Direct Testimony, page 67,
24 lines 10-23 and page 68, lines 1-4).

Line
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1 **Q6. Does the Company agree with intervenor recommendations related to the**
2 **proposed TEP Regulatory Asset authorization and the Company’s ability to**
3 **reallocate funding between rebate programs?**

4 A6. Partially. To start, the Company appreciates the support from Staff Witnesses
5 Freeman and McMillan-Sepkoski regarding the ability to record TEP Regulatory
6 Assets beyond the forward test year of a rate case.

7

8 However, the Company maintains that having the ability to reallocate funding
9 between programs would allow the Company to provide maximum support of EV
10 adoption in instances where one rebate program’s funding is depleted but funding
11 is available elsewhere.

12

13 With that said, the Company appreciates the concerns raised by MEIU Witness
14 Schuster and Staff Witnesses Freeman and Krause related to a lack of oversight if
15 the Company were able to unilaterally shift funding between programs.

16

17 As such, the Company believes that MEIU Witness Schuster’s suggestion is
18 reasonable that the Commission establish “guardrails” that would allow the
19 Company to shift funding between programs if those guardrails were followed. This
20 would allow the Company to respond quickly to prevailing market trends but would
21 not allow it to act unilaterally. Staff could be tasked with establishing appropriate
22 guardrails in consultation with other interested stakeholders.

Line
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1 **Q7. What then does the Company propose related to TEP Regulatory Asset**
2 **authorization and the Company’s ability to reallocate funding between rebate**
3 **programs?**

4 A7. The Company recommends that the Commission:

- 5 • Confirm the Company’s authorization to record TEP Regulatory Assets
- 6 beyond the forward test year in the instant case as supported by Staff
- 7 Witnesses Freeman and McMillan-Sepkoski; and
- 8 • Direct Staff to establish guidelines that would allow the Company to shift
- 9 funding between programs based on prevailing market trends. The Staff
- 10 should establish these guidelines in consultation with other interested
- 11 stakeholders.

12

13 **TEP Regulatory Asset Amortization Period**

14 **Q8. Can you summarize intervenor positions related to the TEP Regulatory Asset**
15 **amortization period?**

16 A8. Yes. NRDC and Sierra Club Witness Woolley provided testimony related to the
17 TEP Regulatory Asset amortization period.

18

19 NRDC and Sierra Club Witness Woolley recommends that the Company move
20 from a 5-year amortization period to a 10-year amortization period for TEP
21 Regulatory Assets, arguing:

22

23 “Amortizing rebates over only 5 years front-loads costs and creates apparent
24 short-term rate pressure, particularly during a period of growing affordability
25 concerns. Extending the amortization period would smooth costs and bring

Line
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1 forward the point at which customers see ratepayer benefits. I recommend that
2 the Commission direct the Company to extend its rebate amortization schedule
3 to 10 years. A 10-year period better matches the useful life of the underlying
4 charging infrastructure investments” (Woolley Direct Testimony, page 7, lines
5 18-21 and page 8, lines 1-2).

6

7 **Q9. What is the Company’s position related to NRDC and Sierra Club Witness**
8 **Woolley’s proposed TEP Regulatory Asset amortization period?**

9 A9. The Company does not object to NRDC and Sierra Club Witness Woolley’s
10 recommendation to move to a 10-year amortization period for TEP Regulatory
11 Assets.

12

13 **TEP Program Improvements**

14 **Q10. Can you summarize intervenor positions related to TEP program**
15 **improvements?**

16 A10. Yes. MEIU Witness Schuster provided testimony related to potential TEP program
17 improvements.

18

19 Throughout her testimony, MEIU Witness Schuster discusses what she believes are
20 best practices of utility EV programming across the varying customer segments
21 (fleet owners, Multi-Unit Dwelling [MUD] property managers, etc.). She
22 recommends the following:

23

24 “In the short term, the Company should:

Line
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- 1 • Assess the viability of working with a third-party contractor to manage
- 2 a portion or all its transportation electrification programs, and lead
- 3 customer engagement efforts;
- 4 • Identify areas of opportunity to improve its E&O programs, specifically
- 5 by developing a robust dealership program, more proactive outreach
- 6 strategies for its existing eFleet Advisory Services and its prospective
- 7 MUD Advisory Services, and opportunities to educate and connect key
- 8 community stakeholders; and
- 9 • Establish clear metrics by which it will begin to evaluate the success of
- 10 its E&O programs.

11

12 In the Company's 2026 TEP, the Company should:

- 13 • Report findings of its viability assessment to work with a third-party
- 14 contractor to manage its transportation electrification programs and
- 15 outreach efforts, detailing the cost assumptions and any benchmarking
- 16 with other utilities used to inform the Company's evaluation;
- 17 • Propose an expansion of the Company's E&O budget to support the
- 18 implementation of more robust and proactive E&O efforts, through
- 19 opportunities such as developing a dealership network program,
- 20 strengthening its Advisory Services offerings, and establishing
- 21 resources and educational opportunities for key community
- 22 stakeholders; and
- 23 • Propose the metrics by which the Company will evaluate the success of
- 24 its E&O efforts, detailing explored alternatives, the variables considered
- 25 for each proposed metric, and the recommended formulae to define each

Line
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1 proposed metric” (Schuster Direct Testimony, page 63, lines 8-18 and
2 page 64, lines 1-10).

3

4 **Q11. Does the Company agree with MEIU Witness Schuster’s recommendations**
5 **related to TEP program improvements?**

6 A11. Partially. To start, the Company appreciates MEIU Witness Schuster’s thorough
7 and thoughtful suggestions on how it could potentially improve its TEP
8 programming. However, the Company notes that its current TEP programming was
9 approved through the Commission’s January 23, 2025 Order in Case No. U-21534
10 (“January 2025 Order”) and was launched shortly after in mid-February. As such,
11 the Company’s current programming had been in place for only six months at the
12 time MEIU Witness Schuster submitted her direct testimony. The Company does
13 not believe such a short time period is adequate to fully assess the effectiveness of
14 its current programming. Further, the Company continues to refine its Education &
15 Outreach (E&O) and advisory service efforts as it gains learnings and experience
16 with its new TEP programs.

17

18 Therefore, the Company does not agree with Witness Schuster’s suggestion that it
19 “[a]ssess the viability of working with a third-party contractor to manage a portion
20 or all of its transportation electrification programs, and lead customer engagement
21 efforts” (Schuster Direct Testimony, page 63, lines 8-9). Likewise, it does not agree
22 that it should report the findings of such an assessment in its 2026 TEP submission.
23 Such an assessment would be unlikely to result in definitive conclusions since the
24 effectiveness of the Company’s current approach is still being explored and
25 assessed. Such an assessment would also run counter to previous Commission

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1 orders which approved the establishment of an internal team to develop and
2 administer the Company's TEP programming¹. Instead, the Company's resources
3 are better spent on improving its current programming, and not on spending time
4 assessing alternative approaches.

5

6 However, the Company believes MEIU Witness Schuster's other recommendations
7 on improving its E&O offerings and establishing meaningful metrics warrant
8 consideration (Schuster Direct Testimony, page 63, lines 10-13). The Company
9 notes that the Commission has established a clear process and timeline for
10 submitting TEPs when it approved new TEP filing requirements through its January
11 24, 2025 Order in Case No. U-21492. The process of updating and submitting the
12 Company's TEP requires robust stakeholder collaboration, and the Company
13 believes that this is the appropriate forum to consider MEIU Witness Schuster's
14 suggestions. Through this stakeholder process, detail and definition can be added
15 to her suggestions and they can be considered and debated amongst interested
16 stakeholders. Any suggestions that are adopted can then be included in the
17 Company's 2026 TEP submission.

18

19 **Q12. What then does the Company propose related to TEP program**
20 **improvements?**

21 A12. The Company proposes that the Commission reject MEIU Witness Schuster's
22 recommendation that it assess the viability of working with a third-party contractor.

¹ In its December 1, 2023 Order in Case No. U-21297, the Commission approved the establishment of a permanent EV programming administration team when it stated "The Commission finds the ALJ's analysis and recommendation in this matter to be thorough and well-reasoned. Therefore, the Commission adopts the PFD and the ALJ's recommendation that the Charging Forward program administration be made permanent and the requested funding be approved" (page 263).

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1 Further, if it feels necessary to do so, the Commission could direct the Company to
2 consider MEIU Witness Schuster's other recommendations as part of stakeholder
3 processes leading up to its 2026 TEP submission.

4

5 **Electric Vehicle (EV) Forecast and Utility Make Ready (UMR) Capital Investment**

6 **Q13. Can you summarize the intervenor positions related to the Company's EV**
7 **forecast and UMR capital investment that you are addressing?**

8 A13. Yes. I am addressing AG Witness Coppola's and Staff Witness Freeman's
9 testimony related to the Company's EV forecast. I will also address AG Witness
10 Coppola's testimony related to the Company's proposed UMR capital investment.

11

12 AG Witness Coppola first highlights that the Company forecasts Utility Make
13 Ready (UMR) investment related to EV charging infrastructure based on its EV
14 adoption forecast. He goes onto argue that the Company's EV forecast is too high
15 and asserts a variety of reasons why EV adoption will be lower than forecast by the
16 Company (Coppola Direct Testimony, pages 29-32). He concludes that:

17

18 "The current environment and demand for EVs does not support the increase in
19 spending forecasted by the Company for 2025 and 2026 for UMR. Although
20 some level of EV sales will continue, the increase in UMR installations over
21 the actual base amount in 2024 is not likely to occur. Therefore, I recommend
22 that the incremental forecasts of \$9.2 million for 2025 and \$18.6 million be
23 removed from the Company's forecasted capital expenditures" (Coppola Direct
24 Testimony, page 32, lines 4-8).

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1 Staff Witness Freeman does not take issue with the Company's current EV forecast
2 in his direct testimony. However, he highlights that the passing of the One Big
3 Beautiful Bill Act (OBBBA) accelerated the sunseting of federal EV tax credits to
4 September 30, 2025. He suggests that this will impact EV adoption and concludes
5 that "[i]n both its next TEP and rate case, Staff expects to see a thorough discussion
6 of these developments and how EV adoption and load will be impacted" (Freeman
7 Direct Testimony, page 5, lines 20-21).

8

9 **Q14. Does the Company agree with intervenor positions related to its EV forecast**
10 **and UMR capital investment?**

11 A14. Partially. Company Witness Leuker addresses AG Witness Coppola's criticisms of
12 the Company's EV forecast and concludes that the Company's EV forecast is
13 appropriate. As such, the Company disagrees with AG Witness Coppola's
14 recommendation to disallow projected UMR capital investment.

15

16 The Company agrees with Staff Witness Freeman's assessment that the accelerated
17 sunseting of EV tax credits could impact EV adoption, and that it is too soon to tell
18 how great those impacts will be. The Company therefore agrees to evaluate such
19 impacts prior to filing its next TEP.

20

21 **Q15. What then does the Company recommend related to its EV forecast and UMR**
22 **capital investment?**

23 A15. The Company recommends that the Commission accept the Company's EV
24 forecast and therefore allow recovery of the projected UMR investment.

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1 The Company further supports that the Commission direct the Company to include
2 a thorough discussion of the impacts of the EV tax credit sunseting in its next TEP
3 filing (due July 1, 2026) and next rate case.
4

5 **TEP Benefit Cost Analysis (BCA)**

6 **Q16. Can you summarize intervenor positions related to the Company's TEP BCA?**

7 A16. Yes. NRDC and Sierra Club Witness Woolley provided testimony related to the
8 Company's TEP BCA.
9

10 In his direct testimony, NRDC and Sierra Club Witness Woolley argues that the
11 Company's TEP is too narrow and conservative, arguing that it "front-loads rebate
12 costs with a 5-year amortization, counts only 10% of projected EV load (ignoring
13 network effects), omits societal benefits, and consequently risks associating the
14 TEP with Michigan's growing affordability concerns, potentially fueling political
15 opposition to EVs" (Woolley Direct Testimony, page 7, lines 13-16). He
16 recommends:
17

18 "... when the Commission-directed BCA collaborative tool becomes available,
19 the Company should be required to use it in its next TEP." (Woolley Direct
20 Testimony, page 9, lines 4-5, footnote omitted).
21

22 **Q17. Does the Company agree with NRDC and Sierra Club Witness Woolley's**
23 **recommendations related to its TEP BCA?**

24 A17. Yes. The Company has already indicated it intends to use the "Commission-
25 directed BCA collaborative tool":

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1 “The Company is participating in Case No. U-20898 and anticipates utilizing
2 the open-source BCA tool in future iterations of its TEP once it becomes
3 available” (Foley Direct Testimony, page 11, lines 5-7).

4

5 Earlier in my rebuttal testimony I addressed NRDC and Sierra Club Witness
6 Woolley’s testimony on Regulatory Asset amortization period.

7

8 **Charging Hub Capital Recovery**

9 **Q18. Can you summarize intervenor positions related to the Company’s proposed**
10 **Charging Hub capital recovery?**

11 A18. Yes. NRDC and Sierra Club Witness Woolley and Staff Witness Freeman provided
12 testimony related to the Company’s proposed Charging Hub capital recovery.

13

14 NRDC and Sierra Club Witness Woolley accurately described how the Company
15 has exited the Charging Hub initiative that was to be sited in Redford, MI. He
16 therefore recommends that the Commission disallow \$96,000 of capital spending
17 that occurred in 2023 and \$1.503 million of 2024 and 2025 capital spending that
18 the Company had proposed for recovery (Woolley Direct Testimony, page 21).

19

20 Staff Witness Freeman also highlighted how the Company has exited the initiative
21 and that the Company is supportive of removing the \$1.503 million of proposed
22 2025 capital spending associated with the project from its request in the instant case
23 (Freeman Direct Testimony, page 7-8). However, Staff Witness Freeman supports
24 recovery of historic spending that occurred in 2023 and 2024, arguing that “[t]hese
25 investments were reasonable and prudent at the time and were for the further

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1 development of the project. The US Department of Transportation changed the
2 grant terms, and this resulted in the Company leaving the project” (Freeman Direct
3 Testimony, page 8, lines 6-8).

4

5 **Q19. Does the Company agree with intervenor recommendations related to its**
6 **proposed Charging Hub capital recovery?**

7 A19. Partially. The Company agrees with NRDC and Sierra Club Witness Woolley’s and
8 Staff Witness Freeman’s assessment of the \$1.503 million of projected 2025 capital
9 investment and therefore withdraws its request for recovery of this amount.

10

11 The Company further agrees with Staff Witness Freeman’s recommendation that
12 \$99,000 of historic spending that occurred in 2023 and 2024 be approved for
13 recovery. As Staff Witness Freeman points out, 2023 and 2024 spending was
14 reasonable and prudent at the time of spending when the Company believed it
15 would fully execute the Charging Hub project. Only after those funds were spent
16 did the US Department of Transportation change the terms of the grant resulting in
17 the Company exiting the initiative. As such, the Company disagrees with NRDC
18 and Sierra Club Witness Woolley’s recommendation to disallow historic capital
19 investment associated with the Charging Hubs project.

20

21 **Q20. What then does the Company recommend related to Charging Hub capital**
22 **recovery?**

23 A20. The Company recommends that the Commission approve recovery of \$99,000 of
24 historic capital spending that occurred in 2023 and 2024. The Company withdraws

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1 its request for recovery of \$1.503 million of 2025 capital investment associated
2 with the Charging Hubs project.

3

4 **Residential Contribution in Aid of Construction (CIAC) Communications**

5 **Q21. Can you summarize intervenor positions related to residential CIAC**
6 **communications?**

7 A21. Yes. NRDC and Sierra Club Witness Woolley provided testimony related to
8 residential CIAC communications.

9

10 NRDC and Sierra Club Witness Woolley argues that some families may decide to
11 install two chargers in their home “in which case the family could easily exceed the
12 9.6 kW waiver threshold and incur significant charges. Such charges would hinder
13 EV adoption” (Woolley Direct Testimony, page 5, lines 6-7).

14

15 To mitigate the impacts of this situation, NRDC and Sierra Club Witness Woolley
16 recommends the Company first identify which customers on its system own EVs.
17 Then “the Company should target these customers with additional outreach efforts
18 that explain the terms of the waiver and give the customer options for how to avoid
19 breaching the waiver’s limits” (Woolley Direct Testimony, page 5, lines 15-17).
20 NRDC and Sierra Club Witness Woolley gives suggestions on how the Company
21 can identify EV owners on its system and the type of messaging it could deliver.

22 NRDC and Sierra Club Witness Woolley asserts that his “proposed actions can be
23 implemented in a highly automated way and with minimal incremental cost”
24 (Woolley Direct Testimony, page 6, lines 5-6) and provides his reasoning for his

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1 assertion (e.g., EV detection tools already exist, communications can be done via
2 existing channels, etc.) (Woolley Direct Testimony, page 6, lines 7-12).

3

4 **Q22. Does the Company agree with NRDC and Sierra Club Witness Woolley's**
5 **recommendations related to residential CIAC communications?**

6 A22. No. MNSC Witness Woolley's recommendations are unnecessary and could result
7 in customer confusion and dissatisfaction.

8

9 The language proposed by Company Witness Willis in direct testimony provides
10 the Company with the option to assess a CIAC charge on a residential customer
11 when it states:

12

13 "Electric vehicle charging equipment exceeding 9.6 kW of demand at the meter,
14 or total connected load exceeding 10 kW (excluding electric vehicle charging
15 equipment), *may be subject to additional charges* in accordance with the
16 Section C6" (Willis Direct Testimony page 30, lines 16-21, emphasis added).

17

18 The Company is not currently charging residential customers CIAC if their total
19 connected load exceeds 10kW. Likewise, if the proposed language is approved by
20 the Commission (subject to Staff Witness Isakson's proposed edits), the Company
21 does not intend to charge residential customers CIAC if their electric vehicle
22 charging equipment exceeds 9.6 kW.

23 As such, proactively reaching out to customers that may exceed the 9.6 kW of
24 charging demand is unnecessary as the Company would be educating customers
25 about a potential charge that it has no intention of levying on those customers. This

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1 could result in customer confusion and dissatisfaction. Further, simply reaching out
2 to customers and discussing a potential charge, even if the Company has no
3 intention of levying it on customers, could hurt EV adoption.

4

5 If in the future the Company changes its policy and plans to begin charging
6 residential customers CIAC for charging equipment in excess of 9.6 kW, then the
7 Company agrees it may be appropriate to proactively reach out and educate
8 customers that may become subject to the charge.

9

10 **Q23. What then does the Company propose related to NRDC and Sierra Club**
11 **Woolley's recommended residential CIAC communications?**

12 A23. The Company recommends that the Commission reject NRDC and Sierra Club
13 Woolley's recommendations related to residential CIAC communications.

14

15 **Recovery of Residential Merchant Fees**

16 **Q24. What intervenor positions related to the Company's proposal to continue to**
17 **recover residential merchant fees through base rates are you addressing?**

18 A24. I will address Staff Witness McMillan-Sepkoski's testimony related to the
19 Company's proposal to continue to recover residential merchant fees through base
20 rates.

21

22 Staff Witness McMillan-Sepkoski recommends that the Company not recover
23 residential merchant fees through base rates. However, consistent with an
24 alternative approach proposed by the Company, she recommends "approval of
25 residential merchant fees to the ALJ and the Commission for recovery in the

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1 forward test year and direct the Company not to request recovery of residential
2 Merchant Fees in its next rate case” (McMillan-Sepkoski Direct Testimony, page
3 11, lines 6-8).

4

5 **Q25. Is the Company maintaining its original proposal that residential merchant**
6 **fees be recovered through base rates?**

7 A25. No. At the time of filing the instant case, the Company believed the most
8 appropriate approach was to treat non-residential customers and residential
9 customers differently as it pertains to merchant fee recovery. Specifically, the
10 Company proposed that non-residential merchant fees be directly charged to
11 customers in line with the Commission’s January 2025 Order, while residential
12 merchant fees continue to be recovered through base rates. Through his direct
13 testimony, Company Witness Ambrose sponsored the Payment Merchant Fee
14 project, which was designed to facilitate this approach while also providing
15 flexibility to charge residential customers directly for merchant fees in the future,
16 if needed.

17

18 Since then, as described by Company Witness Ambrose in rebuttal testimony, the
19 Payment Merchant Fee project has matured, and the Company now believes that it
20 is more efficient to take a single approach to merchant fees for all customers.

21

22 **Q26. What then is the Company’s position related to residential merchant fees?**

23 A26. While the Company appreciates Staff’s support of a longer timeline to begin
24 charging merchant fees directly to residential customers, the Company now plans

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1 to begin charging merchant fees directly to residential customers at the conclusion
2 of the instant case.

3
4 This timing aligns with when the Company will begin charging merchant fees
5 directly to non-residential customers electing to use a card for payments. Further,
6 the Company has developed a robust outreach and education plan for its residential
7 customers to help prepare them for the change.

8
9 As such, the Company withdraws its request for recovery of \$7.013 million of
10 O&M in the forward test year associated with residential merchant fees².

11

12 **Regulated Marketing O&M Normalization Adjustments**

13 **Q27. What intervenor positions related to Regulated Marketing O&M**
14 **normalization adjustments are you addressing?**

15 A27. I will address AG Witness Coppola's recommendations related to Regulated
16 Marketing O&M normalization adjustments.

17

18 **Q28. Did the Company include 2024 O&M normalization adjustments?**

19 A28. Yes. As discussed by AG Witness Coppola, in response to discovery request TMS-
20 2.1, the Company made two normalization adjustments to its 2024 O&M spending
21 which total \$4.909 million. These adjustments include:

- 22 • \$3.563 million related to customer outreach to promote clean energy
23 adoption

² Company Exhibit A-13, Schedule C5.7.1, Page 1, Line 3

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- 1 • \$1.346 million related to deferred backfilling of employees that left the
2 company

3

4 **Q29. Why are the 2024 normalization adjustments necessary?**

5 A29. The first adjustment related to customer outreach is necessary as this spending
6 enables growth of the Company's voluntary renewables program, known as MI
7 Green Power (MIGP). Customer enrollment in MIGP offsets Clean Energy
8 compliance costs which helps create downward rate pressure on non-enrolled
9 customers.

10

11 The second adjustment related to deferred backfilling is necessary as this spending
12 supports a positive customer experience by ensuring the Company has adequate
13 resources to respond to its customers in a timely manner.

14

15 **Q30. What adjustment did AG Witness Coppola propose?**

16 A30. AG Witness Coppola proposed to disallow both normalization adjustments
17 (Witness Coppola Direct Testimony page 128, pages 6-9).

18

19 **Q31. What is AG Witness Coppola's basis for his proposal?**

20 A31. The only justification that AG Witness Coppola offers for the proposed
21 disallowances was to assert the following:

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1 “...the Company continued the reduction in expense past 2023 and into 2024.
2 At this point, the reductions are no longer temporary but reflective of a more
3 permanent level of expense. The proposed normalization to a higher expense
4 level is no longer credible” (Coppola Direct Testimony, page 128, lines 4-6).

5
6 **Q32. Do you agree with AG Witness Coppola’s proposed adjustment?**

7 A32. No. AG Witness Coppola’s argument seems to assume that if a reduction spans two
8 calendar years, then it cannot be considered a “temporary” reduction. This
9 argument is illogical as there is no sound basis for why a temporary reduction would
10 need to be confined to a single calendar year.

11
12 Further, adopting AG Witness Coppola’s proposed disallowance could result in
13 decreased enrollment in the Company’s MIGP program and negatively impact the
14 overall customer service experience for its customers. As such, the Company
15 recommends that the Commission reject AG Witness Coppola’s proposed
16 disallowances.

17
18 **Other Proposed Regulated Marketing Disallowances**

19 **Q33. What other intervenor proposals related to Regulated Marketing**
20 **disallowances are you addressing?**

21 A33. AG Witness Coppola and Staff Witness McMillan-Sepkoski provided testimony
22 related to other Regulated Marketing disallowances that I will address.

23
24 In his testimony, AG Witness Coppola recommends that the Commission disallow
25 \$1.340 million of 2026 forecasted O&M related to the Company’s EV

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1 programming (previously known as “Charging Forward”; currently known as
2 TEP). He offers no justification for the proposed disallowance beyond asserting
3 “increases in expense in future years is speculative at this time” (Witness Coppola
4 Direct Testimony, page 129, lines 2-4).

5
6 In her testimony, Staff Witness McMillan-Sepkoski recommends that the
7 Commission disallow \$244,000 of 2026 forecasted O&M. To arrive at this
8 proposed disallowance, she “applied Staff witness Ufolla’s inflation percentages to
9 the Company’s exhibit A-13, 6 Schedule C5.9 and the result was decrease in O&M
10 expense of \$244,000” (Witness McMillan-Sepkoski, page 8, lines 5-6).

11
12 **Q34. Does the Company agree with these intervenor proposals related to Regulated**
13 **Marketing disallowances?**

14 A34. No. To start, AG Witness Coppola’s assertion that the increase of \$1.340 million
15 related to the Company’s EV programming is “speculative” is demonstrably false.

16
17 The \$1.340 million cited by AG Witness Coppola represents a projected increase
18 in EV programming O&M spending from \$1.965 million in 2024 to \$3.305 million
19 in 2026³.

20
21 This is comprised of two elements:

- 22 • Education & Outreach (E&O) O&M, which is projected to increase from
23 \$1.376 million in 2024 to \$1.500 million in 2026 (i.e., an increase of \$0.124
24 million)

³ Company Exhibit A-12, Schedule B5.9, Line 11

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- 1 • Program Administration O&M, which is projected to increase from \$0.589
2 million in 2024 to \$1.805 million in 2026 (i.e., an increase of \$1.216
3 million)

4

5 However, in 2024 the Company's E&O and Program Administration spending was
6 split between O&M, Regulatory Asset, and capital treatment. When combining the
7 multiple sources of funding, total 2024 spending was:

- 8 • Education & Outreach - \$1.532 million (i.e., \$1.376 million of O&M and
9 \$0.156 million of Regulatory Asset)⁴
10 • Program Administration - \$1.268 million (i.e., \$0.070 million of capital,
11 \$0.589 million of O&M, and \$0.609 million of Regulatory Asset)⁵

12

13 So, in total E&O and Program Administration spending in 2024 was \$2.800 million.

14 As such, the Company is requesting a \$0.505 million increase in O&M from total
15 2024 spending levels, and not \$1.340 million cited by AG Witness Coppola.

16

17 Further, the increase in O&M is supported by the Commission's December 1, 2023
18 Order in Case No. U-21297. In that Order, the Commission adopted "the PFD and
19 the ALJ's recommendation that the [14-person] Charging Forward program
20 administration be made permanent and the requested funding be approved for the
21 reasons stated in the PFD"⁶. Throughout 2024, the Company expanded its program
22 administration team. As such, an increase in spending from 2024 (when the

⁴ Company Exhibit A-12, Schedule B5.9, Lines 9 and 14

⁵ Company Exhibit A-12, Schedule B5.9, Lines 2, 10, and 13

⁶ Case No. U-21297 Order, page 263

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1 program administration team was not fully staffed) to 2025 and 2026 would be
2 expected.

3

4 In summary, the proposed increase in O&M is not “speculative” but is grounded in
5 actual historical spending and supported by previous Commission orders.

6

7 As it relates to Staff Witness McMillan-Sepkoski’s recommendation that the
8 Commission disallow \$244,000 of 2026 forecasted O&M, Company Witness
9 Bruzzano addresses the appropriateness of the Company’s inflation rates. As such,
10 the Company disagrees with Staff Witness McMillan-Sepkoski’s proposed O&M
11 disallowance.

12

13 **Q35. What then does the Company recommend related to the other proposed**
14 **Regulated Marketing disallowances?**

15 A35. The Company recommends that the Commission reject AG Witness Coppola’s and
16 Staff Witness McMillan-Sepkoski’s proposed Regulated Marketing O&M
17 disallowances.

18

19 **Q36. Does this conclude your rebuttal testimony?**

20 A36. 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

REBUTTAL TESTIMONY

OF

TIMOTHY J. LEPCZYK

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF TIMOTHY J. LEPCZYK

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

2 A1. My name is Timothy J. Lepczyk. My business address is DTE Energy Company,
3 One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy
4 Corporate Services, LLC as Assistant Treasurer and Director of Corporate Finance,
5 Insurance and Development.

6
7 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
8 **Company (DTE Electric or Company)?**

9 A2. Yes.

10

11 **Q3. What is the purpose of your rebuttal testimony?**

12 A3. The purpose of my testimony is to rebut the arguments made by Michigan Public
13 Service Commission Staff (Staff) Witness Joseph E. Ufolla, Witness Shannon
14 Rueckert, and Witness Nicholas Evans, Attorney General (AG) Witness Sebastian
15 Coppola, Association of Businesses Advocating Tariff Equity (ABATE) Witness
16 Christopher C. Walters, Attorney General (AG), Michigan Environmental Council
17 (MEC), and Natural Resources Defense Council (NRDC), collectively referred to
18 as “AG-MN” Witness Paul Alvarez and Witness Dennis Stephens, Michigan
19 Environmental Council (MEC), Natural Resources Defense Council (NRDC), and
20 Citizens Utility Board of Michigan (CUB), collectively identified as “MNC”
21 Witness Douglas B. Jester, Natural Resources Defense Council (NRDC) and
22 Citizens Utility Board of Michigan (CUB), collectively referred to as “NRDC-
23 CUB” Witness Richard J. Bunch, and Citizens Utility Board of Michigan (CUB)
24 Witness Matthew Bandyk.

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1 The absence of a discussion of other matters in my rebuttal testimony should not
2 be taken as an indication that I agree with other aspects of any Staff or intervenor
3 testimony.

4

5 **Q4. Are you sponsoring any rebuttal exhibits?**

6 A4. I am sponsoring the following rebuttal exhibit:

7	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
8	A-45	KK1	Updated Projected Cost of Long-term Debt
9	A-45	KK2	Updated Table 1 Rate Impact per \$1M of Investment

10

11 **Q5. Were these exhibits prepared by you or under your direction?**

12 A5. Yes, it was.

13

14 **Capital Structure**

15 **Q6. Do you agree with Staff Witness Ufolla, AG Witness Coppola, ABATE Witness**
16 **Walters, and CUB Witness Bandyk's recommendation for an equity ratio of**
17 **50.0%?**

18 A6. No. As stated in my direct testimony, DTE Electric's plan is to finance and fund
19 over \$7.9 billion of electric capital expenditures for the period January 2024
20 through December 2026 (see Exhibit A-12 Schedule B5). During periods of intense
21 capital investment, maintaining a sound capital structure is essential to the financial
22 well-being of the Company.

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1 **Development of Cost Rates**

2 **Q7. Do you agree with Staff Witness Ufolla's recommendation on page 9-10 of his**
3 **direct testimony for a Long-Term Debt rate of 4.27%?**

4 A7. No. The Company maintains its calculated Long-Term Debt issuance rate of 5.78%
5 for 2026 (as compared against a long-term debt rate for the projected 2026 issuance
6 of 5.44% as calculated by Witness Ufolla), based on an average projected 30-year
7 treasury rate of 4.59% plus a 119 bps spread. Using the projected 5.78% with the
8 actual 2025 issuances, the weighted average long-term debt cost as of December
9 31, 2026, is estimated at 4.29% and shown on Exhibit A-45 Schedule KK1.

10

11 **Q8. Do you agree with Staff Witness Ufolla and AG Witness Coppola's**
12 **recommendation for a Short-Term Debt rate of 3.91%?**

13 A8. No. Given the consistently overly-optimistic forecasts regarding the proximity of
14 Fed rate cuts, we believe the current short-term cost of debt is a more appropriate
15 metric than the market's forecast rate. The S&P Economic Outlook from December
16 2024 forecasted the average Federal Funds rate for 2025 to be 4.02% while the
17 actual average Federal Funds rate in 2025 is 4.33%. Due to the continued market
18 volatility and unknown timing of Fed rate cuts, the Company feels it is reasonable
19 and prudent to use the current and known short-term cost of debt rate of 4.69%,
20 which is calculated using DTE Electric's actual borrowing rate in 2025 of 4.45%
21 plus 0.24% for the cost of credit facility fees.

22

23 **Securitization**

24 **Q9. Do you agree with the rate used by Staff Witness Rueckert and AG Witness**
25 **Coppola to calculate the Return on Tree Trim Regulatory Asset?**

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1 A9. No. The Company maintains its position that any future tree trim surge expenditures
2 should be financed through permanent capital. In past cases (e.g., Case No. U-
3 21015), the Commission directed DTE Electric to retire existing long-term debt and
4 equity with the proceeds from the sale of the securitization property. The Company
5 feels that it is therefore consistent that the return associated with the surge
6 regulatory asset be commensurate with the capital that will ultimately be retired
7 with the proceeds of that securitization. Furthermore, if the Company is ultimately
8 directed to use the short-term debt rate to calculate the return on the tree trim
9 regulatory asset, then the Company would expect to be granted approval to retire
10 short-term debt with the proceeds from the sale of the securitization property.

11

12 **Q10. Do you agree with NRDC-CUB Witness Bunch, MNC Witness Jester, and AG-**
13 **MN Witness Stephens recommendation for the Commission to direct the**
14 **Company to securitize various distribution system program costs?**

15 A10. No. The Company objects to the use of securitizations for these investments in our
16 distribution system. Historically, utility securitizations have been reserved for the
17 recovery of stranded costs which no longer provide a benefit to customers and / or
18 for material non-recurring expenses (e.g., widespread damage caused by severe
19 storms). The somewhat unique decision to securitize tree trimming surge expenses
20 was made to mitigate the year-over-year rate impacts from the increase to this
21 operating expense and to spread the cost to customers more evenly over the time
22 horizon of the anticipated benefits.

23

24 The investments in our distribution system program result in long-lived assets that
25 will provide long-term benefit to customers and merit inclusion in our permanent

Line
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1 capital structure. Distribution investments are fundamentally different than
2 stranded assets or material non-recurring operating expenses. Requirements to
3 securitize distribution investments may misalign priorities and incentives and
4 potentially create headwinds in raising external capital (for example, if there are
5 concerns about the possible securitization of other asset classes; or if rating
6 agencies deem the securitization amounts overly burdensome).

7
8 The Company does recognize the unique attributes that securitizations offer and
9 has utilized this option for tree trimming surge and remaining net book values for
10 post-retirement coal-fired generation assets. The Company recently closed on two
11 securitizations, the first in March 2022 for \$235.8 million to recover costs related
12 to the River Rouge generation site and tree trimming surge program, and the second
13 in October 2023 for \$601.6 million to recover costs related to the Trenton Channel
14 and St. Clair generation sites. The 2022 securitization will mature on December 1,
15 2036 and the 2023 securitization will mature on September 1, 2037. The Company
16 also anticipates two additional securitizations, one in the fourth quarter of 2026 in
17 an amount of approximately \$580 million to recover the book value of Belle River's
18 coal assets and remaining tree trimming surge expenses, and one in one in 2032 in
19 an amount of approximately \$845 million to recover the remaining book value of
20 Monroe power plant.

21
22 **Q11. Do you agree with AG-MN Witness Alvarez & NRDC-CUB Witness Bunch's**
23 **recommendation that securitized loans may be used to manage required O&M**
24 **spending increases?**

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1 A11. No. The Company does not agree with Witness Alvarez & Witness Bunch's
2 recommendation that the Company should securitize distribution system O&M
3 expenses. The securitization process is not a cost-free financing alternative and
4 places administrative burdens on both the Commission and the Company. A
5 securitization requires a Financing Order from the Commission similar to a rate
6 case process and also requires ongoing servicing including daily implementation of
7 charges on bills, monthly certificates, semi-annual cash reconciliations, semi-
8 annual and annual true-ups of charges, and annual audits of the securitization
9 special purpose entities. Closing expenses due to the complexity of the transaction
10 are higher than utility bond financing, and securitizations also require on-going
11 annual service expenses (which are minimal in utility bond financing). The investor
12 universe for purchasing securitization bonds is limited and pricing of the bonds is
13 typically equivalent or higher than utility bond financing. The decision to securitize
14 should be a collaborative effort between the Company and the Commission to
15 address stranded costs which are no longer viable and material non-recurring
16 expenses (such as severe storm restoration, wildfire expenses, and in the case of the
17 Company, our tree trim surge program).

18

19 **Q12. How do the Rating Agencies view the use of Securitization vs. traditional utility**
20 **financing?**

21 A12. While at the margin utility securitizations may be viewed as credit positive by the
22 rating agencies, securitizations may raise credit concerns if these charges become
23 a meaningful percentage of the customer bill. Rating agencies monitor the
24 percentage of securitization charges as a percentage of a customer's total bill and,
25 if the percentage is above a threshold, may consider on-balance sheet treatment of

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1 the debt. Standard & Poor's, in their March 4, 2024 commentary, explain, "If the
2 charge becomes excessive, it increases the possibility of politically driven
3 challenges to the enabling legislation and financing order (i.e., customer revolt).
4 When modeling the cash flows associated with a transaction, we observe how high
5 the projected securitization charge becomes as a percentage of a residential
6 customer's bill and how long the charge remains at such elevated levels, to assess
7 this risk." Moody's Investor Service also comments in their May 2, 2024 rating
8 methodology, "Even if the financing order is irrevocable, the charges or the law
9 that authorizes them could be subject to challenge in the courts or to future political
10 pressure to rescind or change them through legislation. That is more likely the
11 higher the charges, i.e., the more the economic incentive for a challenge or in
12 circumstances where the financial imbalances in a utility system increase.
13 Consequently, our economic analysis focuses on the size of the utility cost recovery
14 charge (UCRC), both in absolute terms and as a percentage of the customers' utility
15 bill." The rating agencies are not anticipating additional securitizations at DTE
16 Electric, and any incremental securitization debt and related charges would need to
17 be reviewed by the agencies to ensure that the new securitization charges, when
18 combined with existing and proposed charges, do not exceed their thresholds for
19 percentage of total customer bill. This is particularly relevant given the material
20 future securitization financings (estimated at ~\$1.4 billion for Belle River's coal-
21 handling assets, for tree trimming surge costs, and for a considerable portion of
22 Monroe's remaining net book value) for which the Company has already committed
23 to execute.

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1 **Q13. Does the Company have concerns with AG-MN Witness Alvarez’s calculation**
2 **and results shown on “Table 1 Rate Impact per \$1M of Investment” on page**
3 **17 of his direct testimony?**

4 A13. Yes. The Company disagrees with the analysis in Table 1 of Witness Alvarez’s
5 testimony that compares the rate impacts of securitization versus recovery of
6 operating expenses versus traditional recovery of capital expenditures.

7

8 First, Mr. Alvarez assumes a securitization financing of 30 years to recover
9 costs. Under Statute 2000 PA 142 as amended, the Commission is empowered to
10 issue a Financing Order authorizing the issuance of Securitization Bonds over a
11 period not to exceed 15 years (Final Maturity Date). The securitization bonds are
12 structured with the Final Maturity Date at least one year after the scheduled final
13 payment debt, limiting the securitization to a maximum of 14 years. Once the
14 shorter term and higher issuance costs are factored into the model, the annual
15 securitization charges on customer bills are materially higher (approximately \$106
16 million annual revenue requirement versus approximately \$69 million average
17 annual revenue requirement as calculated by Mr. Alvarez) than what Witness
18 Alvarez represents.

19

20 Second, Mr. Alvarez failed to apply sales tax to the recovery of operating expenses.
21 For the sake of simplicity, the revisions I have made to Witness Alvarez’s
22 calculations remove the sales tax assumption from all calculations (O&M and
23 capital) as sales taxes are not part of the revenue requirement.

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1 Third, there are multiple errors in his traditional capitalization worksheet. These
2 errors include: (1) book depreciation of the asset that exceeds the original asset cost
3 (i.e., the cumulative depreciation total exceeds \$1,000); (2) improper MACRS
4 schedule (i.e., the total MACRS amount appears to be 102.5% of the asset cost;
5 again, this should not exceed 100%; (3) incorrect calculation of deferred taxes
6 (these should be calculated as the difference between annual book and tax
7 depreciation multiplied by the tax rate); and (4) most notably, use of the less
8 applicable post-tax discount rate (6.03%) instead of the more relevant pre-tax cost
9 of total capital of 7.52%. Once applied, the cost of capital falls materially below
10 the 1.3x factor that Witness Alvarez quotes. My calculation (shown on Exhibit A-
11 45, Schedule KK2) results in a ratio of 1.1x. In addition, I have also created a
12 schedule that uses capitalization ratios more in line with those presented on Exhibit
13 A-14, Schedule 1, which represent DTE Electric's projected rate base. In this
14 calculation, I closely approach the expected 1.0x ratio (since the rate at which the
15 capital is charged is the same rate as that used to discount the corresponding
16 revenue requirement).

17
18 As such, I recommend the Commission reject Witness Alvarez's recommendation
19 to securitize new distribution investments. The proposal is inconsistent with the
20 traditional use of securitization, it would create a potentially problematic and
21 burdensome total securitization obligation, and Witness Alvarez's calculations are
22 inaccurate to the point that his alleged key takeaway (comparable customer cost) is
23 simply incorrect and provides no analytically sound basis of comparison to
24 traditional utility financing.

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1 **Infrastructure recovery mechanism (IRM)**

2 **Q14. Can you summarize Witness Evans' proposal regarding the rate of return for**
3 **the IRM?**

4 A14. Witness Evans states that "Staff also recommends that for 2027-2029, the rate of
5 return associated with the IRM surcharge should be lower than the pretax rate of
6 return (ROR) as ordered in this instant case, but no lower than the short-term debt
7 rate (STD) ordered in the instant case. Once these investments are found to be
8 prudent and reasonable for inclusion in base rates in a future rate case, Staff intends
9 for the normal ROR to apply."
10

11 **Q15. Do you agree with Witness Evans' recommendations?**

12 A15. No. IRM investments are normal long-term utility assets of the Company that are
13 used and useful and provide benefits to customers and which require the
14 opportunity to earn a commensurate rate of return. Witness Evans makes reference
15 to the tree trim regulatory asset as a precedent to support his recommendation, since
16 the tree trim regulatory asset is charged a short-term rate of return. This is not an
17 appropriate comparison. Tree trim surge amounts would ordinarily be recognized
18 as O&M and recovered in the year the expense was recognized. Its appearance on
19 the balance sheet is expressly related to the decision to securitize those amounts to
20 mitigate the rate impact and to spread the cost to customers more evenly over the
21 time horizon of the anticipated benefits. In contrast, the Company finances the IRM
22 assets with the same mix of permanent debt and equity capital that it uses to finance
23 rate base investment. The IRM investments will be funded at the onset with long-
24 term debt and equity, in line with the long-term nature of these assets. A rate of
25 return below the actual cost of permanent capital that finances the investments

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1 would discourage debt and equity investment, ultimately raising the cost of capital
2 paid by customers. Furthermore, in the regulated model, return on capital, on an
3 absolute basis, is highest in year 1 and declines thereafter as the asset is depreciated.
4 Denying the opportunity to earn a rate of return for this first year materially
5 deteriorates the overall return profile of that asset.

6
7 In addition, a construct in which distribution investment returns are lower than
8 those for alternative investments may create misaligned incentives in pursuit of the
9 Company's and the Commission's goal of improving customer reliability.
10 Conversely, there are various precedents in which higher ROEs have been granted
11 when there is alignment around specific policy objectives. For example, higher
12 ROEs were utilized in Michigan to encourage the deployment of renewable energy
13 after the 2008 RPS standard was enacted. FERC has also allowed a higher ROE to
14 incentivize transmission investments.

15
16 Lastly, the fact that the Company is investing more now than before is entirely
17 unrelated to the considerations of investors and the Company's actual cost to finance
18 investments. As further described by Company Witness Willis, Staff Witness Evans
19 does not justify why the fact that the Company invests more now than it did ten
20 years ago is relevant to setting an appropriate ROE. Considering the proposal in its
21 entirety, the Commission should reject Witness Evans' recommendation that the
22 Company should receive a lower ROR on IRM investments.

23

24 **Q16. Does this complete your rebuttal testimony?**

25 A16. 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

REBUTTAL TESTIMONY

OF

JENNIFER E. NELSON

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF JENNIFER E. NELSON

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1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed.**

3 A1. My name is Jennifer E. Nelson and I am employed by Concentric Energy Advisors
4 as a Vice President. My business address is 293 Boston Post Road West, Suite 500,
5 Marlborough, Massachusetts, 01752.

6
7 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
8 **Company (DTE Electric or Company)?**

9 A2. Yes, I did.
10

11 **Purpose of Testimony**

12 **Q3. What is the purpose of your rebuttal testimony?**

13 A3. The purpose of my rebuttal testimony is to respond to the following Michigan
14 Public Service Commission (“Commission”) Staff and intervenor witnesses as they
15 relate to the appropriate return on equity (“ROE”) and capital structure for DTE
16 Electric:

- 17 • Mr. Joseph E. Ufolla on behalf of Commission Staff;
18 • Mr. Sebastian Coppola on behalf of the Attorney General’s (“AG”) office;
19 • Mr. Christopher C. Walters on behalf of the Association of Business Advocating
20 Tariff Equity (“ABATE”);
21 • Mr. Matthew J. Bandyk on behalf of Citizens Utility Board (“CUB”); and
22 • Mr. Matthew T. Lyon on behalf of Walmart Inc. (“Walmart”).

23 I also respond to Mr. Douglas B. Jester on behalf of Michigan Environmental
24 Council, (“MEC”), the Natural Resources Defense Council (“NRDC”), and the
25 Citizens Utility Board of Michigan (“CUB”), collectively identified as “MNC,”

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1 regarding the effect of disallowances on regulatory risk. I collectively refer to these
2 individual witnesses as “the Opposing Witnesses.” My silence on a particular issue
3 should not be construed as agreement with respect to that issue.

4 **Q4. Are you sponsoring any exhibits in this proceeding?**

5 A4. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
Exhibit A-39	DD2.1	Constant Growth DCF Results
Exhibit A-39	DD2.2	Quarterly Growth DCF Results
Exhibit A-39	DD2.3	Expected Market Return Calculations
Exhibit A-39	DD2.4	CAPM and Empirical CAPM Results
Exhibit A-39	DD2.5	Bond Yield Plus Risk Premium Analysis
Exhibit A-39	DD2.6	Corrected Exhibit A-14, Schedule D5.4
Exhibit A-39	DD2.7	Suggested Revisions to Staff’s DCF Analysis
Exhibit A-39	DD2.8	Suggested Revisions to Staff’s Risk Premium Analysis for a Forward Utility Expected Return
Exhibit A-39	DD2.9	Summary of Staff’s Cost of Equity Estimates with Suggested Revisions
Exhibit A-39	DD2.10	Suggested Revisions to Mr. Coppola’s DCF Analysis
Exhibit A-39	DD2.11	Suggested Revisions to Mr. Coppola’s CAPM Analysis
Exhibit A-39	DD2.12	Suggested Revisions to Mr. Coppola’s Risk Premium Analysis
Exhibit A-39	DD2.13	Mr. Walters’ Revised Treasury Bond Risk Premium Analysis
Exhibit A-39	DD2.14	Mr. Walters’ Revised Utility Bond Risk Premium Analysis
Exhibit A-39	DD2.15	Suggested Revisions to Mr. Bandyk’s DCF Analysis

6

7 **Q5. Were these exhibits prepared by you or under your direction?**

8 A5. Yes, they were.

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1 **Summary of Rebuttal Testimony**

2 **Q6. What are your key conclusions regarding the analysis and recommendations**
3 **provided by the Opposing Witnesses regarding the appropriate ROE and**
4 **capital structure for DTE Electric?**

5 A6. My key conclusions are as follows:

6 1. The Opposing Witnesses' analyses contain flaws and inconsistencies that
7 produce certain model results that are far below a reasonable return in the
8 current capital market environment.¹ On pages 7 and 8 of my Direct
9 Testimony, I demonstrate that authorized ROEs for vertically integrated
10 electric utilities have increased in recent years as regulators have
11 acknowledged rising interest rates and the effect those higher interest rates
12 on the cost of equity (see also, Figure 2 of my Direct Testimony). Because
13 DTE Electric competes for capital among other utilities, it is necessary that
14 the Company's authorized ROE keeps pace directionally with the trend of
15 higher interest rates and authorized ROEs. Mr. Bandyk's 8.91 percent
16 recommendation is lower than all authorized vertically integrated electric
17 utility ROEs since January 1, 2022, which is especially problematic given
18 the rising cost of capital in recent years. Mr. Bandyk's ROE
19 recommendation defies any rational basis, does not satisfy the *Hope* and
20 *Bluefield* standards, and should be dismissed from the outset. As shown in
21 Mr. Walters' Table CCW-1, 76 percent of authorized ROEs for electric
22 utilities (including wires-only utilities) in 2024 have been above Mr.
23 Walters' 9.50 percent recommendation. Through July 11, 2025, the

¹ Source: S&P Capital IQ Pro, Regulatory Research Associates ("RRA"). 8.75 percent is the lowest authorized ROE for a vertically integrated electric utility since at least 1980, excluding cases for limited-issue riders, formula rate plans, and ROEs that include penalties.

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1 proportion above 9.50 percent is 65 percent. In other words, Mr. Walters'
2 own data shows his recommendation to be in the lower two-thirds to three-
3 quarters of ROEs authorized for electric utilities. The Opposing Witnesses'
4 recommendations to reduce DTE Electric's authorized ROE are out of sync
5 with market trends of higher interest rates and higher authorized ROEs.

6 2. Each of the Opposing Witnesses' recommends reducing DTE Electric's
7 authorized ROE, yet none of the Opposing Witnesses demonstrate that the
8 Company's risk has reduced or that capital costs have declined such that a
9 departure from the returns available to other vertically integrated electric
10 utility companies is warranted.

11 3. The cost of equity for regulated utility companies is being affected by
12 several key factors in the current and prospective capital markets, including
13 the interest rate environment and central bank monetary policy as well as
14 current inflationary pressure and the longer-term outlook for inflation.
15 Long-term interest rates remain elevated, and economic policy uncertainty
16 has increased. These circumstances also reinforce the importance of
17 considering the results of multiple models, as I have with the Capital Asset
18 Pricing Model (CAPM), Discounted Cash Flow (DCF), and Risk Premium
19 approaches.

20 4. Based on my updated DCF, CAPM, and Risk Premium analyses, I continue
21 to find a reasonable range of ROE for DTE Electric to be in the range of
22 9.90 percent to 11.60 percent and the Company's requested ROE of 10.75
23 percent at the midpoint of the range to be fair and appropriate. In addition,
24 I support DTE Electric's proposed capital structure of 50.75 percent
25 common equity and 49.25 percent long-term debt as reasonable.

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1 **Q7. Please summarize the Opposing Witnesses’ respective ROE and equity ratio**
2 **recommendations for DTE Electric.**

3 A7. The Opposing Witnesses who perform an ROE analysis (Mr. Ufolla, Mr. Coppola,
4 Mr. Walters, and Mr. Bandyk) recommend an authorized ROE for DTE Electric
5 between 8.91 percent and 9.85 percent.² Walmart witness Lyon references
6 authorized returns for electric utilities in Michigan and other jurisdictions and
7 argues that the Commission should consider the impact of the revenue requirement
8 on customers and recognize Michigan’s regulatory framework on the authorized
9 ROE.³ As it relates to capital structure, each of the Opposing Witnesses
10 recommend the Commission reject the Company’s proposed capital structure.
11 They propose that the Commission authorize a hypothetical capital structure
12 consisting of 50 percent common equity and 50 percent debt.⁴
13 As is evident, there are a broad array of recommendations from multiple witnesses.
14 Notably, ROE recommendations as low as 8.91 percent are in the bottom 0.2
15 percent of authorized returns for vertically integrated electric utilities since at least
16 1980.⁵ Some of the Opposing Witnesses’ recommendations are supported by
17 analytical approaches while others are more subjective or based on assumptions
18 related to market to book ratios. I submit that the appropriate method for
19 determining the cost of capital is through the application of rigorous analysis using

² Direct Testimony of Joseph E. Ufolla, page 3, lines 13-18; Direct Testimony of Sebastian Coppola, page 81, lines 6-7; Direct Testimony of Christopher C. Walters, page 3, lines 10-12; Direct Testimony of Matthew J. Bandyk, page 5, lines 3-4.

³ Direct Testimony of Matthew T. Lyon, page 18, lines 4-13.

⁴ Direct Testimony of Joseph E. Ufolla, page 3, lines 13-18; Direct Testimony of Sebastian Coppola, page 71, lines 8-15; Direct Testimony of Christopher C. Walters, page 2, lines 15-16; Direct Testimony of Matthew J. Bandyk, page 5, lines 14-16.

⁵ Source: S&P Capital IQ Pro, Regulatory Research Associates (“RRA”). 8.75 percent is the lowest authorized ROE for a vertically integrated electric utility since at least 1980, excluding cases for limited-issue riders, formula-based rate plans, and ROEs that include penalties.

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1 financial models and market data from reliable sources, coupled with a
2 comprehensive risk assessment of the regulated utility relative to comparable
3 utilities nationwide.

4 Table 1 below summarizes the ROE and equity ratio recommendations in this
5 proceeding. I emphasize that the low end of my recommended range overlaps with
6 the high end of the ranges recommended by Mr. Ufolla, Mr. Coppola, and Mr.
7 Walters. Mr. Bandyk's recommendation, however, is far removed from the other
8 witnesses' recommendations and should be considered an outlier.

9 **Table 1 Summary of Witnesses' ROE and Equity Ratio Recommendations**

Witness	Party	ROE	ROE Range	Equity Ratio
Ufolla	Staff	9.80%	9.40%-10.40%	50%
Coppola	AG	9.85%	9.80% - 9.97%	50%
Walters	ABATE	9.50%	9.00% - 10.00%	50%
Bandyk	CUB	8.91%	8.80% - 9.01%	50%
Lyon	Walmart	<i>No specific recommendation</i>		
Nelson/Lepczyk	DTE Electric	10.75%	9.90% - 11.60%	50.75%

10
11 There are a number of flaws and inconsistencies with the analyses conducted by the
12 Opposing Witnesses. I address each analytical approach and recommend
13 appropriate adjustments where appropriate; if I do not address a particular topic or
14 issue, that does not mean that I agree with it. At the outset, one must question
15 analyses producing results that are below any return authorized for a vertically
16 integrated electric utility since at least 1980.

17 **Q8. Please describe the legal standards that must be met to establish the authorized**
18 **ROE for a regulated public utility such as DTE Electric.**

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1 A8. As discussed in my direct testimony, the standards for a just and reasonable return
2 established by the United States Supreme Court in the *Hope* and *Bluefield* cases
3 are:

4 (1) Financial integrity: the return must be adequate to ensure the company's
5 financial soundness and support credit quality;

6 (2) Capital attraction: the return must be sufficient to enable the company
7 to attract capital on reasonable terms and conditions; and

8 (3) Comparable return: the return must be comparable to those available to
9 investors in firms with commensurate risk.

10

11 **Q9. The Opposing Witnesses reference authorized ROEs for electric utilities in**
12 **other jurisdictions.⁶ Do you agree with their characterization of the trend in**
13 **authorized ROEs and the relevance of the trend on DTE Electric's cost of**
14 **equity?**

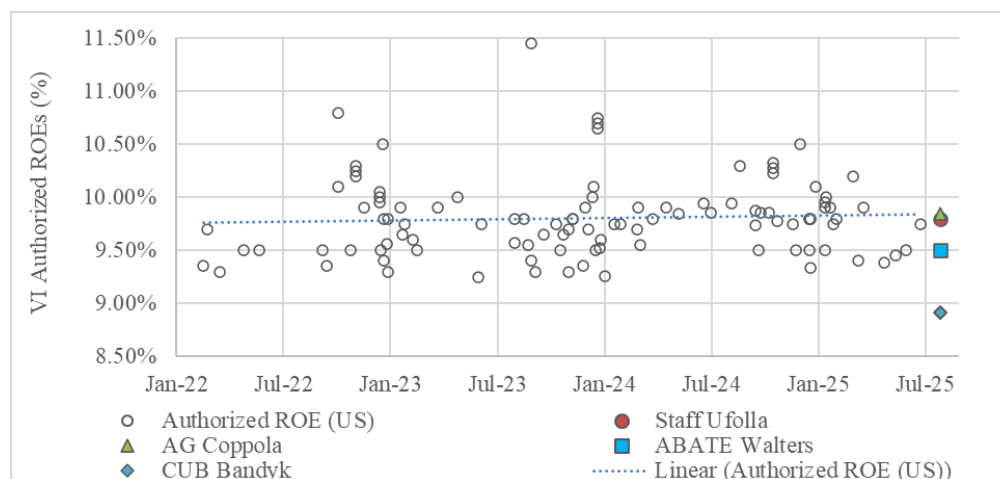
15 A9. National average returns must be placed in the proper context in order to be useful.
16 While I agree that investors consider authorized returns in other states in assessing
17 the reasonableness of the authorized ROE for DTE Electric, I have several concerns
18 with the nationwide average ROE information presented by the Opposing
19 Witnesses. First, several witnesses include authorized ROEs for wires-only electric
20 utilities that are not exposed to generation risk like DTE Electric. Second, market
21 conditions at the time the authorized returns were established are very different than

⁶ Direct Testimony of Joseph E. Ufolla, page 22, lines 10-19 to page 23, lines 1-2; Direct Testimony of Christopher C. Walters, page 3, lines 19-21 to page 5, lines 1-2; Direct Testimony of Matthew J. Bandyk, page 11, lines 13-16 to page 12, lines 3-5; Direct Testimony of Matthew T. Lyon, page 15, lines 1-6 to page 17, lines 1-7.

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conditions going forward. For example, equity returns set when interest rates were very low in 2020 and 2021 are not a reasonable basis of comparison for evaluating the authorized ROE for 2025 when bond yields have increased and are projected to remain elevated as inflation is still elevated as I will explain further below. As shown in Figure 1 below, Mr. Bandyk's and Mr. Walters' ROE recommendations are below the average authorized ROE for vertically integrated electric utilities in 2024 and 2025 (9.81 percent). In addition, Mr. Bandyk's ROE recommendation is unjustifiably below the national averages for vertically integrated electric utilities, as shown as in Figure 1, below. However, the Opposing Witnesses have not demonstrated that the Company's risk profile is meaningfully below other vertically integrated electric utilities, nor that capital costs have declined. On that basis, I conclude that the ROE recommendations are at odds with capital cost trends.

**Figure 1 Vertically Integrated Electric Utility Authorized ROEs 2022-
July 2025 and Opposing Witness Recommendations⁷**



⁷ Source: RRA. Rate case decisions for vertically integrated electric utilities as of July 31, 2025. Excludes decisions with companies that operate under a formula rate plan or decisions with ROE penalties.

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- 1 **Q10. Mr. Coppola refers to authorized ROEs as low as 8.72 percent during the past**
2 **few years and asserts that investors “continue to migrate to utility stocks” by**
3 **reference to market to book ratios.⁸ What is your response?**
- 4 A10. First, Mr. Coppola does not explain which utilities he is referring to that have
5 authorized ROEs as low as 8.72 percent, nor what timeframe he refers to. Therefore,
6 it is difficult to compare whether those utilities are appropriate comparators to the
7 Company. Nearly all of the 17 of 222 authorized ROEs below 9.00 percent since
8 2020 have been for wires-only (or transmission and distribution-only) electric
9 utilities that are not exposed to generation risk like DTE Electric. Most of those
10 decisions were also for Ameren Illinois and Commonwealth Edison that at the time
11 operated under statutory formula rate plans in which the ROE was set by formula
12 on an annual basis by applying a 580 basis point premium to the average 30-year
13 Treasury bond yield. Not only are Ameren Illinois and Commonwealth Edison
14 wires-only utilities, the formula rate plan framework that these utilities operated
15 under at the time is not a comparable regulatory framework. I also note that Green
16 Mountain Power in Vermont operates under a similar Alternative Rate Plan that
17 adjusts the ROE on an annual basis according to a formula that adjusts based on the
18 change in the 10-year Treasury bond yield. Here again, the framework in which
19 the ROE is determined for Green Mountain Power is not comparable to the
20 traditional approach for setting ROEs taken by this Commission.
21 I further note that the market has reacted adversely to unduly low authorized ROEs
22 that are below industry benchmarks and expectations. In 2024, S&P and Moody’s
23 downgraded utilities that operate in Connecticut due to highly restrictive regulatory

⁸ Direct Testimony of Sebastian Coppola, page 102, lines 19-20; page 103, lines 1-10.

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1 outcomes.^{9,10} In discussing Eversource's downgrade, S&P noted that adverse
2 orders for the Avangrid utilities increased Eversource Energy's regulatory risk:

3 *On Nov. 18, 2024, the Connecticut Public Utilities Regulatory*
4 *Authority (PURA) issued final rate-case orders for Connecticut Natural*
5 *Gas Corp. and Southern Connecticut Gas Co., which included material*
6 *base-rate decreases for both utilities. These rate orders follow a recent*
7 *pattern of adverse regulatory developments for investor-owned utilities*
8 *operating in Connecticut, which we believe has increased business risk*
9 *for Eversource Energy and its Connecticut-based subsidiaries.*¹¹

10 Both S&P Global Ratings and its affiliate Regulatory Research Associates (RRA)
11 downgraded its assessment of Connecticut's regulatory construct to the lowest tier.
12 Additionally, Arizona Public Service Company ("APS") was downgraded
13 following a November 2021 order that included an 8.70 percent ROE¹² inclusive
14 of a 20-basis point penalty. RRA commented that the decision was "negative from
15 an investor perspective" that imposed "numerous disallowances on the utility, and
16 has garnered strong reactions in the investment community."¹³ RRA further noted
17 that the decision was "expected to impede APS' ability to earn its authorized return
18 in the first year of new rates."¹⁴ Lastly, RRA lowered the ranking of Arizona
19 regulation to Below Average/3, its lowest ranking. Despite a decision in March

⁹ S&P Global Ratings, "Eversource Energy Issuer Credit Rating Lowered To 'BBB+' From 'A-'; Subsidiaries Ratings Also Lowered; Outlooks Stable," December 9, 2024, <https://disclosure.spglobal.com/ratings/en/regulatory/article/-/view/type/HTML/id/3297352>.

¹⁰ S&P Global Ratings, "Connecticut Natural Gas Corp. And Southern Connecticut Gas Co. Downgraded To 'BBB+' On Final Rate Orders, Outlook Stable," December 6, 2024, <https://disclosure.spglobal.com/ratings/en/regulatory/article/-/view/type/HTML/id/3296633>.

¹¹ S&P Global Ratings, "Eversource Energy Issuer Credit Rating Lowered To 'BBB+' From 'A-'; Subsidiaries Ratings Also Lowered; Outlooks Stable," December 9, 2024, <https://disclosure.spglobal.com/ratings/en/regulatory/article/-/view/type/HTML/id/3297352>.

¹² I note that the case was appealed and the authorized ROE was increased to 8.90 percent on remand.

¹³ Regulatory Research Associates, "Arizona Public Service electric rate case decision viewed as negative for investors," December 3, 2021.

¹⁴ Regulatory Research Associates, "Arizona Public Service electric rate case decision viewed as negative for investors," December 3, 2021.

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1 2024 that increased the authorized ROE to 9.55 percent, APS's credit rating has
2 remained the same.

3 Second, with respect to Mr. Coppola's assertion that investors have not
4 "abandoned" utilities,¹⁵ I note that the relevant question is not whether utilities
5 have maintained access to capital; the question is at what price and on what terms?
6 Such adverse decisions result in increasing the cost of capital (both debt and equity
7 costs), which is ultimately borne by customers. In the end, customers pay the price
8 of poor regulatory outcomes. Therefore, it is in customers' best interest that
9 Michigan's regulatory environment maintains its perception as being predictable
10 and constructive. An authorized ROE that trends in the opposite direction of higher
11 capital cost environments, or that is not in keeping with prior decisions on a relative
12 basis, would introduce a level of uncertainty with respect to the predictability of the
13 regulatory environment in Michigan.

14 **Capital Market Conditions**

15 **Q11. Please summarize recent changes in the economic and financial markets since**
16 **you prepared your Direct Testimony.**

17 A11. Since the Company filed its rate case on April 24, 2025, several changes have
18 occurred. Inflation has ticked upward and expectations for inflation are higher.
19 Long-term government and utility bond yields are slightly higher than they were at
20 the time I prepared my Direct Testimony. Moreover, economic policy uncertainty
21 is high, posing a challenge for business investment and consumer sentiment.

¹⁵ Direct Testimony of Sebastian Coppola, page 102, lines 19-20; page 103, lines 1-6.

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1 Turning first to government and utility bond yields, the 30-day averages on
2 government and utility bond yields have increased just under 10 basis points, as
3 shown in Table 2.

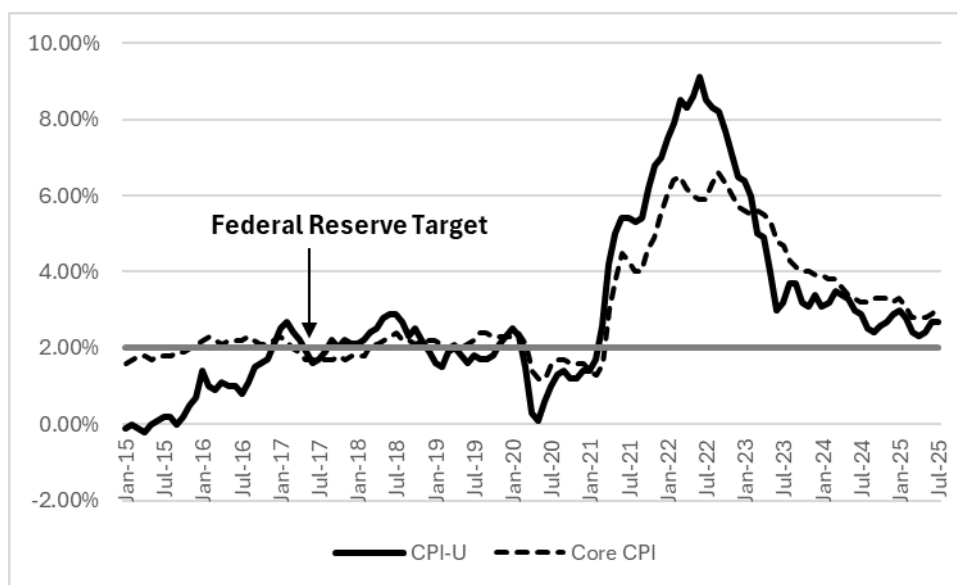
4 **Table 2 Government and Utility Bond Yields (30-Day Averages)¹⁶**

	1/31/2025	7/31/2025	Change (basis points)
30-Year Treasury Bond	4.82%	4.90%	+8
Moody's Utility 'A' Index	5.79%	5.88%	+9
Moody's Utility 'Baa' Index	6.02%	6.08%	+6

5

6 As shown in Figure 2, the pace of inflation (both the overall inflation rate and
7 core inflation rate) has stalled, but remains elevated above the Federal Reserve's
8 2.0 percent target.

9 **Figure 2 Year-Over-Year Consumer Price Inflation (2015-2025)¹⁷**



¹⁶ Sources: Federal Reserve Bank of St. Louis FRED Economic Data and Bloomberg Professional.
¹⁷ Source: U.S. Bureau of Labor Statistics.

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1 Further, the Producer Price Index increased 3.3 percent year over year in July
2 2025, the largest 12-month increase since February 2025.¹⁸ The increase in
3 wholesale prices is an indicator that consumer prices may continue to rise in the
4 near term.
5 U.S. consumers continue to expect inflation to remain elevated. As the University
6 of Michigan's Surveys of Consumers Director Joanne Hsu explains regarding
7 consumer sentiment on inflation for August 2025:

8 *Year-ahead inflation expectations moved up from 4.5% last month to*
9 *4.8% this month. This rise was seen across multiple demographic*
10 *groups. Independents and Republicans both exhibited month-over-*
11 *month increases; expectations for Democrats were unchanged from*
12 *July. Long-run inflation expectations edged up from 3.4% in July to*
13 *3.5% in August. This month ended two consecutive months of receding*
14 *inflation for short-run expectations and three straight months for long-*
15 *run expectations.*¹⁹

16 **Q12. Please discuss recent changes in U.S. trade policy.**

17 A12. During the first half of 2025, the Trump administration announced, implemented,
18 or delayed implementation of tariffs on numerous U.S. trade partners. Significant
19 among these announcements, on April 2, 2025, President Trump announced the
20 administration would impose a 10 percent base tariff on all imports from nearly
21 every country plus an additional "reciprocal" tariff customized for each of
22 approximately 60 countries.²⁰ These reciprocal tariffs were subsequently paused,

¹⁸ Source: U.S. Bureau of Labor Statistics, "Producer prices up 3.3 percent from July 2024 to July 2025, August 22, 2025, <https://www.bls.gov/opub/ted/2025/producer-prices-up-3-3-percent-from-july-2024-to-july-2025.htm>.

¹⁹ University of Michigan, Survey of Consumers, "Final Results for August 2025", Accessed August 30, 2025, <https://www.sca.isr.umich.edu/>.

²⁰ <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/>.

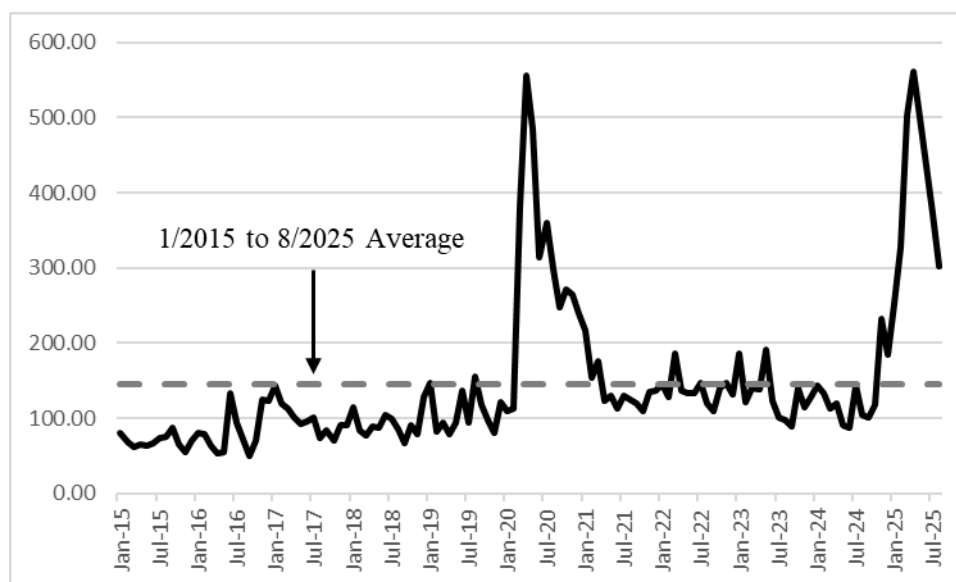
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1 but significant uncertainty remains around the future course of U.S. trade policy
2 and how it will affect the economy.

This created significant policy and market uncertainty; as can be seen in Figure 3 below, the Federal Reserve Bank of St. Louis' Economic Policy Uncertainty Index (the "Index") spiked to levels not seen since the COVID-19 pandemic. While the Index has partially subsided in recent months (to 308.50 as of August 2025), it is still significantly above the average level over the past 10 years (146.51) and the average level during the pendency of DTE Electric's last rate case (140.66). This indicates that there is still significant uncertainty related to international trade and the economy. Uncertainty increases risk and discourages investment, which increases the cost of equity, all else equal.

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Figure 3 Economic Policy Uncertainty Index January 2015 – August 2025²¹



Response to Staff Witness Ufolla

Q13. Please summarize Staff Witness Ufolla's ROE recommendation for DTE Electric.

A13. Mr. Ufolla recommends an ROE of 9.80 percent, with a recommended range of 9.40 percent to 10.40 percent.²² His recommendation is a *reduction* of 10 basis points in the Company's current authorized ROE, despite higher capital costs since the Company's last rate case. In Case U-21534, Mr. Ufolla filed testimony on July 26, 2024 recommending a 9.90 percent return on equity, within a range of 9.30 percent to 10.30 percent.²³ In other words, Mr. Ufolla increased his recommended ROE range in this proceeding, but inexplicably reduced his overall recommendation to 9.80 percent. The 30-day average for 30-year interest rates

²¹ Federal Reserve Bank of St. Louis Economic Database (FRED), Economic Policy Uncertainty Index for United States (USEPUINDXD), monthly average frequency updated August 29, 2025, <https://fred.stlouisfed.org/series/USEPUINDXD>.

²² Direct Testimony of Staff Witness Joseph E. Ufolla, page 11, lines 3-4.

²³ Case No. U-21534, Direct Testimony of Staff Witness Joseph E. Ufolla, page 6, line 9; page 8, lines 5-6.

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1 through July 31, 2024 was 4.45 percent, or approximately 45 basis points *lower*
2 than the 30-day average through July 31, 2025 of 4.90 percent. As noted by the
3 Commission in earlier proceedings, the Commission considers “a variety of market
4 factors in future applications, including market reactions to recent events and
5 measures of volatility and uncertainty, as well as measures of investor confidence,
6 and the utility’s risk profile.”²⁴ Capital costs have increased since the last case, and
7 must be considered in recommending an ROE. A reduction in the authorized ROE
8 when capital costs are rising impedes DTE Electric’s ability to provide a
9 compensatory return to investors who provide the capital that funds the Company’s
10 ability to serve customers.
11 Further, Mr. Ufolla’s current recommended range minimum of 9.40 percent is 21
12 basis points below his lowest model result, according to Chart 4 of his Direct
13 Testimony.²⁵ Moreover, his 9.80 percent ROE recommendation is below the
14 average (10.03 percent) and midpoint (9.97 percent) of his four model results
15 shown in his Chart 4. Mr. Ufolla provides no justification for selecting an ROE
16 that is below the benchmarks supported by his analysis.

17 **Q14. Are there areas of agreement between you and Mr. Ufolla?**

18 A14. Yes. I agree with Mr. Ufolla’s reliance on earnings growth rates in his DCF
19 analysis, as well as calculation of the forward-looking dividend yield. In our CAPM
20 analyses, we both use projected 30-year Treasury bond yields as the risk-free rate
21 and adjusted 5-year Beta coefficients sourced from Value Line.

²⁴ May 8, 2020, Order in Case No. U-20561, page 177.

²⁵ Direct Testimony of Staff Witness Joseph E. Ufolla, page 23, lines 7-8.

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1 **Q15. Please summarize the principal areas in which you disagree with Mr.**
2 **Ufolla's analyses and conclusions.**

3 A15. The principal areas in which I disagree with Mr. Ufolla include: (1) his proxy group
4 selection; (2) the application of the DCF analysis, in particular the appropriate stock
5 price averaging period; (3) his application of the CAPM and his criticism of my
6 ECAPM analyses; (4) his application of the Risk Premium approach; and (5) his
7 estimates for authorized returns for 2024 and 2025. Table 3 below shows my
8 recommended adjustments to Mr. Ufolla's analyses. As a result, the ROE range
9 increases to 9.70 percent to 11.50 percent, with a midpoint of 10.60 percent (see
10 also Exhibit A-39, Schedule DD2.9).

11 **Table 3 Summary of Cost of Equity Estimate Revisions**

<u>ROE Result</u>	<u>As Filed</u>	<u>Revised</u>	<u>Change (basis points)</u>
DCF	Average: 9.61% Median: 9.66%	Average: 9.71% Median: 9.80%	+10-14
Historical CAPM	Average: 9.86% Median: 9.95%	none	none
Risk Premium	10.31%-10.32%	11.50% -11.51%	+120
2024-2025 Authorized ROEs	9.68%-9.74%	9.74%-9.84%	+6-10
ROE Range	9.40%-10.40%	9.70%-11.50%	+30-40
ROE Midpoint	9.80% ²⁶	10.60%	+80

12

13 Proxy Group

14 **Q16. As a preliminary matter, did you find any errors with Mr. Ufolla's proxy**
15 **group statistics reported on his Exhibit S-4, Schedule D-5 page 2?**

16 A16. Yes, I did. Mr. Ufolla's Exhibit No. S-4, Schedule D-5, page 2 (Proxy Group tab)
17 calculated an average that inadvertently excludes four of his proxy companies.
18 However, correcting the formula does not materially change the outcome of his

²⁶ I note that 9.80 percent is below the midpoint of Mr. Ufolla's recommended range of 9.40 percent to 10.40 percent. The precise midpoint is 9.90 percent.

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1 table. I note however, that Mr. Ufolla misstates DTE Electric's current Moody's
2 issuer rating as Aa3 when it is actually two notches lower at A2. I further note that
3 DTE Electric's net plant as of December 31, 2024 as reported on its FERC Form 1
4 is approximately \$26.9 billion, not \$20.0 billion.²⁷
5

6 **Q17. Please describe Mr. Ufolla's proxy group development.**

7 A17. To develop his proxy group, Mr. Ufolla began with Value Line's electric utilities.
8 He then eliminated companies for various reasons, including availability of Value
9 Line reports, payment of dividends, merger or transaction activity, credit rating,
10 and size (including a screener of \$8-\$55 billion net plant screener), leaving 16
11 proxy companies in his proxy group.²⁸ As noted by Mr. Ufolla, 11 proxy group
12 companies overlap in our analyses.²⁹ As discussed below, my proxy group better
13 reflects DTE Electric's operations and risk profile.
14

15 **Q18. Do you agree with Mr. Ufolla's proxy group?**

16 A18. No, I do not. Mr. Ufolla's screening criteria is overly restrictive and produces a
17 proxy group that is not comparable to DTE Electric. For example, one of his six
18 screening criteria specifies that a proxy company must have net plant between \$8
19 billion and \$55 billion. However, Mr. Ufolla does not explain his reasoning for this
20 arbitrary range. I further note that his net plant thresholds are *lower* in this case than
21 they were in the Company's last rate case. In Case No. U-21534, Mr. Ufolla's net
22 plant screening criterion was \$10 billion to \$80 billion.³⁰ Given that net plant
23 increases over time (including for DTE Electric), it is unclear why a lower net plant

²⁷ DTE Electric FERC Form 1, pages 108-109, line 6 (December 31, 2024).

²⁸ Direct Testimony of Staff Witness Joseph E. Ufolla, page 13, lines 3-7; and JEU Exhibit No. S-4, Schedule D-5, page 2 of 12.

²⁹ Direct Testimony of Staff Witness Joseph E. Ufolla, page 13, lines 9-10.

³⁰ Case No. U-21534, Direct Testimony of Joseph E. Ufolla, page 10, line 8 (July 26, 2024).

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1 screening criterion thresholds (in particular the top end of the threshold) is
2 reasonable. An inconsistent approach to the proxy group screening methodologies
3 without a change in the underlying composition of the universe of companies
4 introduces a perception of bias. As explained in my response to Mr. Coppola, DTE
5 Electric is highly comparable to my proxy group in terms of various size-based
6 metrics including electric net plant, electric operating revenue, electric operating
7 income, electric sales volume, and electric customers. Thus, I believe my proxy
8 group is comparable to DTE Electric.
9 Further, it is difficult to discern his reasoning for removing several companies from
10 his proxy group, as Mr. Ufolla does not include information on which companies
11 passed or did not pass each of his screening criteria. Further, his Exhibit No. S-4,
12 Schedule D-5, page 2 of 12, includes additional criteria, such as dividend payout
13 ratios, Value Line Beta coefficients, and holding company equity ratios. Thus, it is
14 unclear as to whether these additional criteria affect the proxy group composition.

15 **Q19. Does Mr. Ufolla screen for companies that are vertically integrated and are**
16 **exposed to generation risk?**

17 A19. No, he does not. Wires-only (or “T&D”) utilities are not exposed to generation risk
18 and thus are not comparable to vertically integrated electric utilities. Therefore,
19 CenterPoint Energy, Consolidated Edison, Eversource Energy, and Public Service
20 Enterprise Group should be excluded from the proxy group. Further, I have
21 removed TXNM Energy (as well as Northwestern Energy Group, which is not in
22 Mr. Ufolla’s proxy group) from my updated analysis because both of those
23 companies recently announced transactions involving a merger or acquisition of the

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1 entire company.³¹ Excluding these companies increases Mr. Ufolla's DCF results
2 from 9.61-9.66 percent to 9.71-9.80 percent, as shown in Exhibit A-39 Schedule
3 DD2.7.

4 DCF Analysis

5 **Q20. Please summarize Mr. Ufolla's DCF analysis.**

6 A20. Mr. Ufolla performs a Constant Growth DCF analysis which produces an ROE
7 average of 9.61 percent and median of 9.66 percent for his proxy group. For the
8 stock price, Mr. Ufolla developed a three-month average price for each proxy
9 company using the closing stock price for April-June 2025 from Yahoo! Finance.
10 For the growth rate component, Mr. Ufolla relies on the three sources for earnings
11 growth: Value Line; Zacks; and Seeking Alpha. I note that we both used Value Line
12 and Zacks earnings growth estimates in deriving growth rates for our respective
13 DCF analyses. Mr. Ufolla developed a dividend yield by multiplying last quarter's
14 dividend from Yahoo! Finance for each proxy company by four to estimate an
15 annualized dividend rate, and multiplied the annualized dividend rate by one-half
16 the average annual growth rate, which is the same approach that I use.

17

18 **Q21. Are there areas of agreement between you and Mr. Ufolla?**

19 A21. Yes. I agree with Mr. Ufolla's reliance on earnings growth rates in his DCF
20 analysis, as well the half-year dividend adjustment noted earlier.

21

22 **Q22. What is your response to Mr. Ufolla's criticisms of your DCF analysis?**

³¹ See, <https://www.txnmenergy.com/~media/Files/P/PNM-Resources/press-release/Acquisition%20Investor%20Release.pdf> and <https://www.northwesternenergy.com/docs/default-source/default-document-library/about-us/investors/financials/final-bkh---nwe-press-release.pdf>

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1 A22. First, Mr. Ufolla criticizes my use of a 30-day, 90-day, and 180-day average stock
2 price in my DCF analysis.³² He contends that the 30-day average is too short to
3 “prevent temporary fluctuations in stock price from skewing the results” and that
4 my 180-day average is unnecessary. Rather, he argues that the 90-day price average
5 is “sufficient enough to mitigate the issues skewness that can occur in a shorter time
6 period, but a longer timeline is simply not necessary.”³³ Mr. Ufolla also notes that
7 my dividend and growth rates are higher than his.³⁴ These differences are likely
8 driven by the differences in proxy group (e.g., his inclusion of wires-only utilities
9 that are not vertically integrated), and the timing of our data.

10 Regarding Mr. Ufolla’s criticism of my stock price averages, Mr. Ufolla does not
11 provide evidence to support his assertions that the 30-day average is too short to
12 prevent temporary fluctuations from skewing the results, that the 180-day average
13 is unnecessary, or that the 90-day average is “sufficient” alone to prevent skewness
14 of the results. I note that in Case No. U-21534, Mr. Ufolla relied on dividend yields
15 calculated by Value Line,³⁵ which calculates its dividend yield as “cash dividends
16 estimated to be declared in the next 12 months *divided by the recent price*.”³⁶

17 Further, as explained in my Direct Testimony, I include three averaging periods to
18 ensure that the model’s results are not skewed by anomalous events that may affect
19 stock prices on any given trading day.³⁷ Importantly, as also stated in my Direct
20 Testimony, the average period should reasonably reflect the expected capital
21 market conditions over the long term.”³⁸

³² Direct Testimony of Staff Witness Joseph E. Ufolla, page 15, lines 14-22; page 16, lines 1-4.

³³ Direct Testimony of Staff Witness Joseph E. Ufolla, page 15, lines 18-20.

³⁴ Direct Testimony of Staff Witness Joseph E. Ufolla, page 16, lines 2-4.

³⁵ Case No. U-21534, Direct Testimony of Joseph E. Ufolla, page 12, line 8.

³⁶ How to Invest in Common Stocks: The Guide to Using the Value Line Investment Survey, page 20

³⁷ Direct Testimony of Jennifer E. Nelson, page 24, lines 1-3.

³⁸ Direct Testimony of Jennifer E. Nelson, page 24, lines 3-5.

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1 With regard to Mr. Ufolla's argument that my growth and dividend growth rates
2 are higher for my proxy group, as already discussed above, I maintain that my proxy
3 group is appropriate, particularly given that Mr. Ufolla failed to exclude distribution
4 only proxy companies that do not bear generation risk, as do vertically-integrated
5 companies like DTE Electric. As shown in Exhibit A-39 Schedule DD2.7, when
6 excluding CenterPoint Energy, Consolidated Edison, Eversource Energy, and
7 Public Service Enterprise Group as distribution-only companies, as well as TXNM
8 Energy for merger and acquisition (M&A) activity, this revised proxy group
9 increases the expected dividend yield by 10 basis points, from 3.51 percent to 3.61
10 percent, and increases his proxy group mean and median ROE estimates to 9.71
11 percent and 9.80 percent, respectively.³⁹

12

13 CAPM Analysis

14 **Q23. Please summarize Mr. Ufolla's CAPM analysis.**

15 A23. Mr. Ufolla applies a projected 2026 risk-free rate of 4.40 percent from IHS Markit,
16 five-year Beta coefficients from Value Line of 0.79, and a historical market risk
17 premium of 6.94 percent for 1928-2024. These inputs result in an average CAPM
18 ROE estimate of 9.86 percent and a median of 9.95 percent.⁴⁰

19

20 **Q24. Do you agree with Mr. Ufolla's criticism that your use of a current risk-free**
21 **rate is not congruent with the test year?**⁴¹

22 A24. No, I do not. As stated in my Direct Testimony, I relied on both a current and a
23 projected risk-free rate, whereas Mr. Ufolla relied only on a projected risk-free rate.

³⁹ See Exhibit A-39 Schedule DD2.7.

⁴⁰ Direct Testimony of Staff Witness Joseph E. Ufolla, page 17, lines 6-22, page 18, lines 13-15; and JEU Exhibit S-4, Schedule D-5, page 6 of 12.

⁴¹ Direct Testimony of Staff Witness Joseph E. Ufolla, page 19, lines 5-6.

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1 As explained in my response to Mr. Coppola, both current and projected is
2 reasonable. Lastly, if Mr. Ufolla's criticism is that only forward-looking inputs are
3 congruent with DTE Electric's forward test year, his reliance only on a historical
4 market risk premium would also not be "congruent" with the test year.
5

6 **Q25. Do you agree with Mr. Ufolla's criticism that your "forward-looking [V]alue**
7 **[L]ine models have results that are out of alignment with all other models."?**⁴²

8 A25. As a preliminary matter, I note that I developed a forward-looking CAPM analysis,
9 as well as a historical CAPM analysis. I also note that I assessed two forward-
10 looking market returns, one based on Value Line estimates and another based on
11 Bloomberg estimates. In order to be conservative, I relied on the lower of the two:
12 Value Line, estimated at 15.29 percent. As I detailed in my Direct Testimony, my
13 Value Line forward-looking CAPM analysis is well within the bounds of
14 reasonableness; approximately 50 percent of the time since 1926, the market return
15 has been at least 15.29 percent.⁴³ My updated analysis uses a Value Line forward-
16 looking market return of 15.03 percent. Since 1926, approximately 51 percent of
17 the annual market returns were at or above 15.03 percent.
18

19 **Q26. Please summarize Mr. Ufolla's concerns with your empirical CAPM**
20 **("ECAPM") analysis.**

21 A26. Mr. Ufolla asserts that my ECAPM analysis is unnecessary due to the use of long-
22 term interest rates and Blume Adjusted betas in my traditional CAPM analysis.⁴⁴
23 Specifically, Mr. Ufolla does not agree with the use of the ECAPM "especially in
24 conjunction with the use of a Value Line (or Bloomberg) adjusted beta instead of a

⁴² Direct Testimony of Staff Witness Joseph E. Ufolla, page 19, lines 2-3.

⁴³ Direct Testimony of Jennifer E. Nelson, page 32, lines 3-6.

⁴⁴ Direct Testimony of Staff Witness Joseph E. Ufolla, page 18, lines 17-22 and; page 19, lines 1-20.

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1 raw beta.”⁴⁵ Mr. Ufolla argues that the inputs used in his CAPM analysis already
2 account for many of the shortcomings recognized by the ECAPM, rendering it
3 “unnecessary”. According to Mr. Ufolla, the Blume adjusted Beta coefficients and
4 long-term risk-free interest rates used in regulated proceedings flatten the slope of
5 the Security Market Line curve.⁴⁶

6

7 **Q27. Do you agree?**

8 A27. No, I do not. As explained in my response to Mr. Coppola below, the ECAPM
9 formula that I rely on applies a conservative alpha adjustment that reflects the use
10 of a long-term risk-free rate.
11 As discussed in my Direct Testimony, the ECAPM reflects published research that
12 companies with lower Beta coefficients tend to have higher returns than those
13 predicted by the CAPM, and those with higher Beta coefficients tend to have lower
14 returns than expected.⁴⁷ Beta coefficient adjustments such as those used by Value
15 Line, on the other hand, address the tendency of “raw” Beta coefficients to regress
16 toward the market mean of 1.00 over time. As explained below, the ECAPM is not
17 an adjustment to the Beta coefficient; the two are different issues and are addressed
18 with different methods.⁴⁸ The relationship between expected returns from the
19 CAPM and ECAPM can be seen in Figure 4, below. Figure 4 illustrates that,
20 whether adjusted or unadjusted, when Beta coefficients are less than 1.00, the
21 CAPM understates the expected return, relative to the ECAPM.

⁴⁵ Direct Testimony of Staff Witness Joseph E. Ufolla, page 19, lines 8-9.

⁴⁶ Direct Testimony of Staff Witness Joseph E. Ufolla, page 19, lines 19-22 and; page 20, lines 1-4.

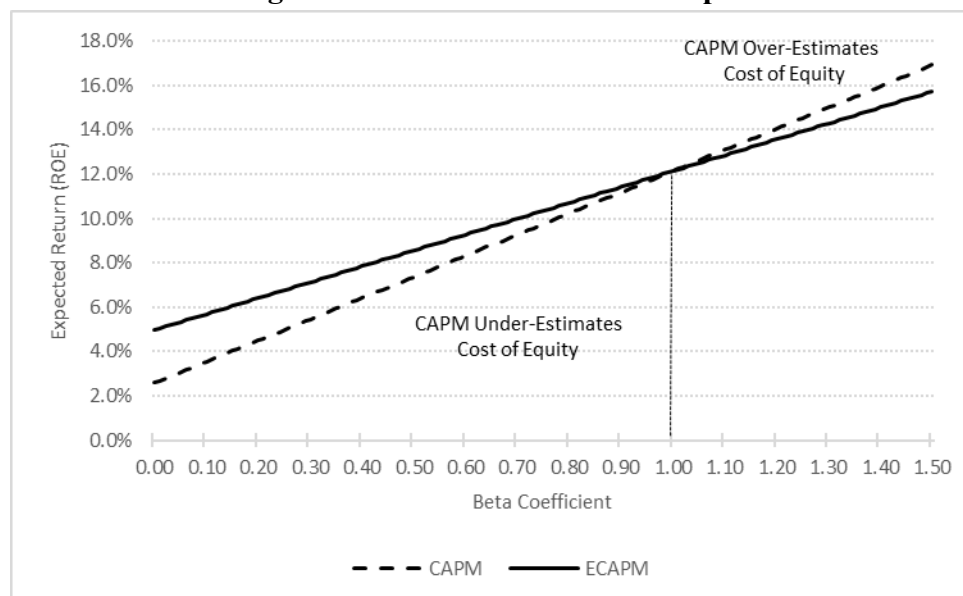
⁴⁷ Direct Testimony of Jennifer E. Nelson, pages 34, lines 18-20; page 35, lines 1-21; page 36, lines 3-27 and lines 31-32; and page 37, lines 1-6. *See also*, Roger A. Morin, PhD., New Regulatory Finance, Public Utility Reports, Inc., at 175-176 (2006).

⁴⁸ Roger A. Morin, PhD., New Regulatory Finance, Public Utility Reports, Inc., at 191 (2006).

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1

Figure 4: CAPM and ECAPM Expected Returns



2

3 The ECAPM is an adjustment to the risk/return line which, as shown in Figure 4
4 above, is flatter than the CAPM assumes. That adjustment is required even with
5 the use of adjusted Beta coefficients, such as those provided by Value Line. As
6 Dr. Morin observes (emphasis added):

7 *Fundamentally, the ECAPM is not an adjustment, increase or decrease,*
8 *in beta. This is obvious from the fact that the expected return on high*
9 *beta securities is actually lower than that produced by the CAPM*
10 *estimate. The ECAPM is a formal recognition that the observed risk-*
11 *return tradeoff is flatter than predicted by the CAPM based on myriad*
12 *empirical evidence. The ECAPM and the use of adjusted betas*
13 *comprised two separate features of asset pricing...Both adjustments are*
14 *necessary.*⁴⁹

15

16 **Q28. Please explain why Value Line adjusts its Beta coefficients.**

⁴⁹ Roger A. Morin, PhD., New Regulatory Finance, Public Utility Reports, Inc., at 191 (2006) [emphasis added].

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1 A28. Value Line's adjustment is based on the research of Marshall Blume, who found
2 that "[n]o economic variable including the beta coefficient is constant over time."⁵⁰
3 Consistent with that finding, Blume observed a tendency of raw Beta coefficients
4 to change gradually over time and that the tendency to regress toward 1.0 was
5 stronger for lower risk portfolios:

6 *...there is obviously some tendency for the estimated values of the risk*
7 *parameter [beta] to change gradually over time. This tendency is most*
8 *pronounced in the lowest risk portfolios, for which the estimated risk in*
9 *the second period is invariably higher than that estimated in the first*
10 *period. There is some tendency for the high risk portfolios to have lower*
11 *estimated risk coefficients in the second period than in those estimated*
12 *in the first. Therefore, the estimated values of the risk coefficients in one*
13 *period are biased assessments of the future values, and furthermore the*
14 *values of the risk coefficients as measured by the estimates of β_1 tend to*
15 *regress towards the means with this tendency stronger for the lower risk*
16 *portfolios than the higher risk portfolios. (emphasis added)*

17 Blume proposed a correction for that "regression bias" to provide more accurate
18 assessments of risk and, therefore, the Cost of Equity:

19 *For individual securities as well as portfolios of two or more securities,*
20 *the assessments adjusted for the historical rate of regression are more*
21 *accurate than the unadjusted or naïve assessments. Thus, an*
22 *improvement in the accuracy of one's assessments of risk can be*
23 *obtained by adjusting for the historical rate of regression even though*
24 *the rate of regression over time is not strictly stationary.⁵¹*

25 Based on Blume's results, Value Line adjusts its "raw" Beta coefficients
26 according to the following formula:

27
$$\beta_{adjusted} = 0.35 + (0.67 \times \beta_{raw}) \quad [1]$$

28 **Q29. Did Marshall Blume's study include utility companies?**

⁵⁰ Marshall E. Blume, *On the Assessment of Risk*, The Journal of Finance, Vol. XXVI, No. 1, March 1971.

⁵¹ Marshall E. Blume, *On the Assessment of Risk*, The Journal of Finance, Vol. XXVI, No. 1, March 1971.

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1 A29. Yes. Blume's study included all common stocks listed on the New York Stock
2 Exchange (NYSE) during any part of the period from January 1926 to June 1968,
3 which includes any utilities listed on the New York Stock Exchange at that time.
4 For example, Consolidated Edison, AEP, and Duke Energy were listed on the
5 NYSE in 1968.

6
7 **Q30. Are you aware of any academic studies that support the use of adjusted Beta**
8 **coefficients in the ECAPM for utility companies?**

9 A30. Yes, in my Direct Testimony, I referenced a 2011 study by Stéphane Chrétien and
10 Frank Coggins⁵² in which the authors studied the CAPM and its ability to estimate
11 the risk premium for the utility industry in particular subgroups of utilities. The
12 study considered the traditional CAPM approach, the Fama-French three-factor
13 model, and a model similar to the ECAPM method that I apply. In the study, the
14 ECAPM relied on adjusted Beta coefficients similar to the approach applied by
15 Value Line. As Chrétien and Coggins found, the ECAPM significantly
16 outperformed the traditional CAPM model at predicting the observed risk premium
17 for the various utility subgroups.

18
19 **Q31. Is the ECAPM an accepted methodology?**

20 A31. Yes, it is. I am aware that the ECAPM (sometimes referred to as the "Zero Beta
21 CAPM") has been accepted by regulatory commissions in Alaska, Maryland,
22 Mississippi, New York, and North Carolina.⁵³ Additionally, I am aware the

⁵² Stéphane Chrétien and Frank Coggins. *Cost Of Equity For Energy Utilities: Beyond The CAPM*. Energy Studies Review, vol. 18, no. 2 (2011).

⁵³ See, Regulatory Commission of Alaska, Docket No. P-97-4, Order No. 151, at 146; Maryland Public Service Commission, Case No. 9311, Order No. 85724, at 105; Mississippi Public Service Commission, Docket No. 01-UN-0548, *Notice of Intent of Mississippi Power Company to Change Rates for Electric Service in its Certificated Areas in the Twenty-Three Counties of Southeast Mississippi*, Final Order, December 3, 2001, at 19; New York Public Service Commission, Case 16-G-0058, *Proceeding on*

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1 ECAPM has been presented by state regulatory commission staff in Maryland,
2 Nevada, and by the Department of Commerce in Minnesota.⁵⁴
3 Finally, the North Carolina Utilities Commission accepted the ECAPM in Duke
4 Energy Carolinas' and Duke Energy Progress' most recent rate cases, including the
5 use of adjusted Beta coefficients in the ECAPM.⁵⁵ Consequently, I believe the
6 ECAPM is a reasonable approach and should be considered by the Commission.

7 Risk Premium Analysis

8 **Q32. Please describe Mr. Ufolla's Utility Risk Premium Analysis.**

9 A32. Mr. Ufolla develops two risk premium estimates: (1) the difference between
10 historical utility equity and utility bond returns; and (2) the difference between
11 historical utility equity and Treasury bond returns. His analysis reviews the
12 historical risk premium investors received "for choosing to invest in the equity of a
13 utility company as opposed to a less risky utility bond or Treasury bond."⁵⁶
14

Motion of the Commission as to the Rates, Charges, Rules and Regulations of KeySpan Gas East Corporation d/b/a National Grid for Gas Service, Order Adopting Terms of Joint Proposal and Establishing Gas Rate Plans, December 16, 2016, at 32; In the Matter of Application of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina, Docket No. E-22, Sub 562 Order Accepting Public Staff Stipulation in Part, Accepting CIGFUR Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase, February 24, 2020, at 40; In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation, Docket No. E-7, Sub 1276, Order Accepting Stipulations, Granting Partial Rate Increase, Requiring Public Notice, And Modifying Lincoln CT CPCN Conditions, at 209-210; In the Matter of Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation, Docket No. E-2, Sub 1300, Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Public Notice, at 162-163.

⁵⁴ See, Maryland Public Service Commission, Case No. 9311, Order No. 85724, at 88; Minnesota Public Utilities Commission, MPUC Docket No. G011/GR-15-736, *Findings of Fact, Conclusions of Law, and Recommendation*, August 19, 2016, at 29; Public Utilities Commission of Nevada, Docket No. 12-02019, Second Modified Final Order, at 36.

⁵⁵ *In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation, Docket No. E-7, Sub 1276, Order Accepting Stipulations, Granting Partial Rate Increase, Requiring Public Notice, And Modifying Lincoln CT CPCN Conditions, at 209-210; In the Matter of Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation, Docket No. E-2, Sub 1300, Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Public Notice, at 162-163.*

⁵⁶ Direct Testimony of Joseph E. Ufolla, page 21, lines 6-7.

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1 **Q33. Do you agree with Mr. Ufolla's Risk Premium Analysis?**

2 A33. Not entirely. My primary concern is that Mr. Ufolla's Utility Risk Premium
3 analyses do not capture the inverse relationship between bond yields and the equity
4 risk premium. Mr. Ufolla's analysis using 1931-2024 data does not account for the
5 inverse relationship between equity risk premium and overall interest rate at that
6 time. Specifically, as interest rates increase, the equity risk premium decreases, and
7 vice versa. Thus, the risk premium is not constant over time. Accordingly, a
8 statistical relationship to identify the relationship between interest rates and returns
9 is critical. Mr. Ufolla's analysis using earned returns from 1931-2024 does not
10 capture this inverse relationship, despite the fact that equity markets and Treasury
11 bond yields moved in different directions during the historical period. Lastly, Mr.
12 Ufolla does not consider a forward-looking utility risk premium analysis. A
13 forward-looking analysis would better align Mr. Ufolla's Risk Premium analysis
14 with the Company's forward test period in this proceeding.

15

16 **Q34. Can you describe the revisions you made to Mr. Ufolla's Risk Premium**
17 **Analysis to address your concerns regarding a forward-looking utility risk**
18 **premium analysis?**

19 A34. Yes. As mentioned above, Mr. Ufolla does not consider a forward-looking utility
20 risk premium analysis, relying instead on the the Electric Utility Realized Market
21 Return Average from 1931 through 2024 for the market return estimate.⁵⁷ As shown
22 in Exhibit A-39 Schedule DD2.8, I supplemented Mr. Ufolla's analysis to calculate
23 a forward-looking market return for the utility industry by applying the Constant
24 Growth DCF approach to the S&P 500 Utilities Index that consists of the 32 utility
25 companies included in the S&P 500 Index. This approach is the same approach I

⁵⁷

Direct Testimony of Joseph E. Ufolla, page 21, lines 9-10.

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1 use to estimate the forward market return estimate for the S&P 500 Index;;
2 however, it is limited to just the utility companies in the S&P 500 Index. Using the
3 S&P 500 Utilities Index companies, I calculated two estimates for the estimated
4 market return, 12.39 percent using long-term earnings growth rates estimates from
5 Value Line and 11.62 percent from Bloomberg. Averaging these two estimates, I
6 derived a forward-looking utility return of 12.00 percent. Applying this estimate to
7 Mr. Ufolla's Risk Premium analysis results in an increase of approximately 50 basis
8 points, or 11.50 percent to 11.51 percent ROE.

9
10 **Q35. Please respond to Mr. Ufolla's concerns regarding your Bond Yield Plus Risk**
11 **Premium Analysis.**

12 A35. Mr. Ufolla disagrees with the use of authorized ROEs as a measure of the investor
13 required return and he disagrees with use of a current bond yield because it does
14 not align with the future test year.⁵⁸ I note that Mr. Ufolla's sole reliance on the
15 historical earned return on utility stocks also does not align with the forward test
16 year.

17 As explained at page 41 of my direct testimony, authorized ROEs in other
18 jurisdictions are a significant part of the market information that investors consider
19 when evaluating their investment alternatives. Therefore, they are a direct measure
20 of returns available to other electric utilities, as required under the comparable
21 return standard of the *Hope* and *Bluefield* decisions. By applying current and
22 projected bond yields to the regression coefficients produced by the model, it
23 provides a forward-looking estimate of the ROE under similar market expectations.

⁵⁸ Direct Testimony of Joseph E. Ufolla, page 22, lines 6-8.

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1 Authorized Returns

2 **Q36. Please summarize Mr. Ufolla's conclusions regarding authorized rate of**
3 **return decisions for electric utilities in other states.**

4 A36. Mr. Ufolla reviews authorized rate of return decisions for electric utilities around
5 the country for the 2024 and early 2025 period, calculating an average authorized
6 return for 2024 of 9.74 percent and 9.68 percent for 2025.⁵⁹

7
8 **Q37. Do you agree with Mr. Ufolla's conclusions regarding authorized rate of**
9 **returns in 2024 and 2025?**

10 A37. No, I do not. Mr. Ufolla fails to exclude authorized ROEs for distribution-only
11 electric utilities that do not bear the generation risk that vertically-integrated
12 companies such as DTE Electric bear. Table 4 below shows the comparison of Mr.
13 Ufolla's results versus vertically-integrated rate cases (through July 31, 2025). As
14 shown in Table 4, authorized ROEs for vertically integrated electric utilities have
15 been higher on average.

16 **Table 4 Revised Allowed ROEs Reported by Mr. Ufolla⁶⁰**

<u>Year</u>	<u>ROEs Allowed AS FILED</u>	<u>Rate Cases (No.) AS FILED</u>	<u>ROEs Allowed REVISED (Vertically- Integrated Only)</u>	<u>Rate Cases (No.) REVISED (Vertically- Integrated Only)</u>
Q1 2025	9.72%	16	9.83%	10
Q2 2025	9.59%	7	9.52%	4
2025 Weighted Average	9.68%	23	9.74%	14
Q1 2024	9.66%	12	9.67%	7
Q2 2024	9.71%	9	9.90%	3
Q3 2024	9.73%	16	9.88%	8
Q4 2024	9.82%	18	9.90%	14
2024 Weighted Average	9.74%	55	9.84%	32

⁵⁹ Direct Testimony of Joseph E. Ufolla, page 22, lines 21-22; and page 23, lines 1-7.

⁶⁰ Source: RRA as of July 31, 2025. As shown in Table 4, there were only four decisions in Q2 2025, which is too few to draw a meaningful conclusion.

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1 **Response to AG Witness Coppola**

2 **Q38. Please summarize AG Witness Coppola's ROE recommendation for DTE**
3 **Electric.**

4 A38. Mr. Coppola recommends an ROE of 9.85 percent, based on his model results that
5 range from 9.80 percent to 9.97 percent.⁶¹ Mr. Coppola explains that his 9.85
6 percent recommendation was developed by giving 50 percent weight to his DCF
7 result of 9.80 percent, 25 percent weight to his CAPM result of 9.97 percent and 25
8 percent weight to his Equity Risk Premium result of 9.86 percent.⁶²
9 Importantly, Mr. Coppola's recommendation runs counter to the current capital cost
10 environment that DTE Electric faces when raising capital. Mr. Coppola
11 recommends a reduction in the Company's authorized ROE, even though capital
12 costs have increased since the Company's last rate case. Because the cost of equity
13 is a cost the Company pays to raise and retain equity capital and is part of its cost
14 of service, it must have the opportunity to recover its capital costs just like any
15 component of the revenue requirement. A reduction in the authorized ROE when
16 capital costs are rising impedes DTE Electric's ability to provide a compensatory
17 return to investors who provide the capital that funds the Company's ability to serve
18 customers.

19

20 **Q39. Is the DCF approach "more reliable" than the CAPM or Risk Premium**
21 **approaches as Mr. Coppola asserts?**⁶³

⁶¹ Direct Testimony of Sebastian Coppola, page 81, line 7;; and page 105, lines 17-18.

⁶² Direct Testimony of Sebastian Coppola, page 106, lines 1-6.

⁶³ Direct Testimony of Sebastian Coppola, page 106, lines 1-2.

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1 A39. No. No single methodology is more reliable than any other in all market
2 environments. As Mr. Ufolla correctly observes, “[n]o one methodology provides
3 an exact measure of a fair rate of return”.⁶⁴
4

5 **Q40. Are there areas of agreement between you and Mr. Coppola?**

6 A40. Yes. I agree with Mr. Coppola’s reliance on analysts’ projected earnings growth
7 rates in his DCF analysis. Additionally, we both use the 30-year Treasury bond
8 yield as the risk-free rate and Value Line as a source of 5-year Beta coefficients in
9 the CAPM analysis.
10

11 **Q41. Please summarize the principal areas in which you disagree with Mr.**
12 **Coppola’s analyses and conclusions.**

13 A41. The principal areas in which I disagree with Mr. Coppola include: (1) his proxy
14 group selection; (2) the growth rate assumptions used in his DCF analyses; (3) his
15 application of the CAPM; and (4) the application of the Risk Premium approach.

16 Proxy Group

17 **Q42. Please describe Mr. Coppola’s proxy group selection.**

18 A42. To develop his proxy group, Mr. Coppola began with the 38 companies classified
19 in Value Line’s Electric Utilities industry. He then eliminated 26 companies for
20 various reasons, including size, M&A activity, certain business risk factors (such
21 as offshore wind and wildfire risk exposure), and non-utility operations, leaving
22 just 12 proxy companies in his proxy group.⁶⁵ As discussed below, my proxy group
23 better reflects DTE Electric’s operations and risk profile.
24

25 **Q43. Do you agree with Mr. Coppola’s proxy group?**

⁶⁴ Direct Testimony of Joseph E. Ufolla, page 12, lines 16-17.

⁶⁵ Direct Testimony of Sebastian Coppola, page 84, lines 6-16; Exhibit AG-30.

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1 A43. No, I do not. Mr. Coppola's screening criteria is overly restrictive and produces a
2 proxy group that is not comparable to DTE Electric.

3

4 **Q44. Does Mr. Coppola screen for companies that are vertically integrated and are**
5 **exposed to generation risk?**

6 A44. No, he does not. Wires-only (or "T&D") utilities are not exposed to generation risk
7 and thus are not comparable to vertically integrated electric utilities. Therefore,
8 CenterPoint Energy and Consolidated Edison should be excluded from the proxy
9 group. Excluding these two companies increases Mr. Coppola's DCF results from
10 9.80 percent to 9.93 percent as shown in Exhibit A-39 Schedule DD2.10.

11

12 **Q45. Please comment on Mr. Coppola's screen for merger and acquisition**
13 **activity.⁶⁶**

14 A45. Mr. Coppola's screen for transaction activity is overly restrictive and does not
15 review whether the transaction skews a company's market data. The primary
16 reason to exclude companies involved in significant transactions or merger activity
17 is because stock prices and other market data can be skewed when transactions are
18 announced. However, some transactions are relatively small and are not significant
19 enough to affect the market data. For example, each of the Entergy Corporation
20 transactions to sell the New Orleans and Louisiana gas distribution assets only
21 represented approximately 2.5 percent of Entergy Corporation's market
22 capitalization at the time the transaction was announced. Further, the sale of these
23 gas distribution businesses renders Entergy Corporation more comparable to DTE
24 Electric as an electric utility by increasing the proportion of Entergy Corporation's

⁶⁶

Direct Testimony of Sebastian Coppola, page 84, lines 12-14; Exhibit AG-30.

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1 business that is regulated electric operations. Lastly, the market reacted very little
2 to the announcement, as Entergy Corp.'s stock price increased only 2.3 percent
3 after the announcement. For these reasons, I do not believe this transaction is
4 significant enough to warrant excluding Entergy Corporation. Entergy Corporation
5 is a vertically integrated electric utility that also owns nuclear generation like DTE
6 Electric and is therefore exposed to similar operating risks. I note that I have
7 removed TXNM Energy and Northwestern Energy Group from my proxy group in
8 my updated analysis because both of those companies recently announced
9 transactions involving a merger or acquisition of the entire company.⁶⁷

10

11 **Q46. Does Mr. Coppola's screen for size accurately reflect companies that are**
12 **similar in size to DTE Electric?**⁶⁸

13 A46. No. Although I appreciate Mr. Coppola's acknowledgement that a company's size
14 affects its risk and therefore the returns that investors require, I disagree with his
15 use of revenue for the consolidated holding company to screen for size. First, Mr.
16 Coppola's revenue screen thresholds do not adequately reflect the distribution of
17 revenue among electric utilities. There are only two electric utility holding
18 companies with revenue less than \$1 billion according to Mr. Coppola's Exhibit
19 AG-30 (Unitil Corp. and MGE Energy), but five above \$20 billion, which means
20 that his thresholds are more likely to exclude companies above his \$20 billion
21 revenue threshold than those below \$1 billion. Moreover, Duke Energy, NextEra
22 Energy, and Southern Company are vertically integrated electric utilities that own
23 nuclear generation, like DTE Electric.

⁶⁷ See, <https://www.txnmenergy.com/~media/Files/P/PNM-Resources/press-release/Acquisition%20Investor%20Release.pdf> and <https://www.northwesternenergy.com/docs/default-source/default-document-library/about-us/investors/financials/final-bkh---nwe-press-release.pdf>

⁶⁸ Direct Testimony of Sebastian Coppola, page 84, lines 7-9; Exhibit AG-30.

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1 The purpose of the screening criteria is to determine whether a company's regulated
2 electric operations are the principal source of long-term growth and thus are
3 comparable to DTE Electric. Because revenue may be several steps removed from
4 the earnings and cash flows that form the foundation of equity valuations, it may
5 lead to the misleading conclusion that a given operating unit is the primary driver
6 of expected growth when the majority of earnings and cash flows are derived from
7 other business segments. For these reasons, other measures of size should be
8 reviewed.

9

10 **Q47. What additional metrics did you review to compare the size of DTE Electric**
11 **to your proxy group?**

12 A47. To assess whether my proxy group is comparable in size to DTE Electric, I
13 compared DTE Electric to my proxy group based on several other measures of size,
14 including electric operating revenue, electric operating income, customer count,
15 electric sales, and electric net plant. As summarized in Table 5 below, DTE Electric
16 is highly comparable to my proxy group median on these measures of size.
17 Therefore, I continue to believe my proxy group is reasonable on balance.

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Table 5 Size Metrics: DTE Electric vs. Proxy Group (2024)⁶⁹

	DTE Electric	Proxy Group Median
Electric Operating Revenue (\$ Million)	\$6,160.76	\$6,072.17
Electric Net Utility Operating Income (\$ Million)	\$1,436.37	\$1,425.29
Electric Plant In Service (\$ Million)	\$29,754.54	\$31,428.13
Electric Net Utility Plant (\$ Million)	\$26,910.32	\$25,658.37
Electricity Sales Volume (MWh)	49,003,398	49,996,319
Electric Customers	2,279,071	2,192,829

2

3 **Q48. Do you agree with Mr. Coppola's review of historical earnings per share**
4 **("EPS") growth as a screening criterion?⁷⁰**

5 A48. No, I do not. The cost of equity is forward looking and is based on investors'
6 expectations of future growth, not historical growth. Historical earnings can be
7 skewed by one-time events that may not reflect future earnings potential. Even
8 DTE Electric's operating revenue has fluctuated up and down at times. Mr. Coppola
9 correctly relies on projected earnings growth rate in his DCF analysis; therefore, a
10 screening criterion based on historical earnings growth rates is inappropriate.

11 DCF Analysis

12 **Q49. Please summarize Mr. Coppola's DCF analysis described on pages 85 and 86**
13 **of his direct testimony and shown in Exhibit AG-25.**

14 A49. Mr. Coppola performs a Constant Growth DCF analysis which produces an ROE
15 estimate of 9.80 percent for his proxy group. For the dividend yield component,
16 Mr. Coppola takes the average of Value Line's projected dividends per share for
17 2025 and 2026. For the growth rate component, Mr. Coppola relies on the average

⁶⁹ Source: S&P Capital IQ. Median of my proxy group presented in my direct testimony.
⁷⁰ Direct Testimony of Sebastian Coppola, page 84, lines 18-20; Exhibit AG-30, page 2.

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1 of Value Line's long-term earnings growth rate projections and the short-term (1
2 year) earnings growth rate projection from Yahoo! Finance.

3
4 **Q50. What are your primary concerns with Mr. Coppola's DCF analysis?**

5 A50. My primary concern is his use of Yahoo's short-term earnings growth rate. In
6 November 2024, Yahoo ceased publishing its long-term consensus earnings growth
7 rate projections and only publishes short-term projections for the current year and
8 one year out. Because the Constant Growth DCF model assumes a growth rate in
9 perpetuity, long-term earnings growth rate projections should be used. The
10 earnings growth rate forecasts that I rely on are the longest term forecasts that I am
11 aware of. Short-term growth rates are more susceptible to exogenous events that
12 may bias growth expectations over the next year. A better substitute for Yahoo's
13 short-term earnings growth rates would be to use long-term earnings growth rates
14 from Zacks Investment Research.⁷¹ Zacks growth rates are publicly available,
15 represent a consensus view, and coincide with the 3-5 year long-term growth rates
16 published by Value Line.

17 A secondary concern is that Mr. Coppola relies only on two sources of earnings
18 growth rate projections. This exposes his analysis to the potential for bias if one of
19 the sources does not publish an earnings growth forecast, resulting in his analysis
20 being dependent on a single estimate of growth (as is the case for CenterPoint
21 Energy and Evergy, as shown in Exhibit AG-25). A more robust analysis would
22 rely on at least three sources of earnings growth rate estimates to mitigate the
23 potential that a single growth rate estimate skews the analysis.

24 As shown in Table 6 and Exhibit A-39 Schedule DD2.10, substituting long-term
25 earnings growth rate projections from Yahoo with Zacks increases his DCF-based

⁷¹ See, www.zacks.com

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ROE estimate from 9.80 percent to 9.97 percent. Excluding CenterPoint Energy (“CNP”) and Consolidated Edison (“ED”) because they are not vertically integrated electric utilities produces an average ROE estimate of 10.07 percent. The results are nearly identical if the average of the three earnings growth rate projections from Value Line, Yahoo, and Zacks are used.

Table 6 Summary of Mr. Coppola’s Revised DCF Analysis⁷²

	Average Expected Dividend Yield	Average Earnings Growth Rate	DCF Result
Mr. Coppola’s DCF Analysis As Filed	3.66%	6.14%	9.80%
Revised (Value Line and Zacks EPS Growth)	3.66%	6.30%	9.97%
Revised (Value Line, Yahoo, and Zacks EPS Growth)	3.66%	6.30%	9.96%
As Filed (Excluding CNP and ED)	3.80%	6.14%	9.93%
Revised (Value Line and Zacks EPS Growth, excluding CNP and ED)	3.80%	6.27%	10.07%
Revised (Value Line, Yahoo, and Zacks EPS Growth, Excluding CNP and ED)	3.80%	6.28%	10.07%

Q51. What is your response to Mr. Coppola’s criticisms of your DCF analysis?

A51. Mr. Coppola asserts that the difference in our DCF analyses are driven by differences in our respective proxy groups and the timing of data.⁷³ For the reasons discussed earlier, Mr. Coppola’s proxy group is too narrow and not comparable to DTE Electric, particularly due to his inclusion of companies that are not vertically integrated. Additionally, Entergy Corporation, Duke Energy, NextEra Energy, and Xcel Energy all own nuclear generation like DTE Electric and should be included.

⁷² Exhibit A-39 Schedule DD2.10. Numbers may not sum due to rounding.

⁷³ Direct Testimony of Sebastian Coppola, page 87, lines 8-17; and page 88, lines 1-9.

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1 No proxy group will be exactly identical in risk to DTE Electric and all utilities
2 face different business risks. However, on balance, a broader proxy group mitigates
3 the effect of any single risk factor.

4 In response to Mr. Coppola's concerns regarding my analyses being out of date, I
5 have updated my analysis to reflect market data as of July 31, 2025. As shown in
6 Exhibit A-39 Schedule DD2.1 and discussed in the Updated ROE Analysis Section
7 below, my updated Constant Growth DCF results range using mean earnings
8 growth rates range from 10.45 percent to 10.52 percent. My updated Quarterly
9 Growth DCF results using mean earnings growth rates range from 10.67 percent to
10 10.74 percent.

11 CAPM Analysis

12 **Q52. Please summarize Mr. Coppola's CAPM analysis.**

13 A52. As explained at pages 89-90 of his testimony and Exhibit AG-26, Mr. Coppola
14 applies a risk-free rate of 4.46 percent, five-year Beta coefficients from Value Line,
15 and the long-term historical average market risk premium between 1926 and 2024
16 of 7.35 percent. These inputs produce an average CAPM-based ROE estimate of
17 9.97 percent for his proxy group.

19 **Q53. Do you have any comments regarding Mr. Coppola's risk-free rate?**

20 A53. Yes. Mr. Coppola relies on my projected risk-free rate of 4.46 percent. However,
21 he misunderstands the timeframe of the projection, erroneously assuming the
22 projection is for 2026.⁷⁴ As explained in my Direct Testimony, the 4.46 percent
23 projected risk-free rate is the average of (1) the average projected 30-year Treasury
24 yield for the six quarters ended Q2 2026; and (2) the average long-term projected
25 30-year Treasury yield for the years 2026-2030 and 2031-2035 reported by Blue

⁷⁴

Direct Testimony of Sebastian Coppola, page 89, footnote 64.

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1 Chip Financial Forecasts (“Blue Chip”).⁷⁵ If Mr. Coppola’s intent is to use the
2 projected 30-year Treasury bond yield for 2026, then his risk-free rate should be
3 4.65 percent, which is the current average projected 30-year Treasury bond yield
4 between Q1 2026 to Q4 2026 reported by Blue Chip.⁷⁶ Revising Mr. Coppola’s
5 CAPM analysis for the current 2026 projected risk-free rate produces a CAPM
6 result for his proxy group of 10.16 percent, as shown in Exhibit A-39 Schedule
7 DD2.11.

8

9 **Q54. Are you “unsure” which risk-free rate is appropriate as Mr. Coppola**
10 **asserts?**⁷⁷

11 A54. No. Mr. Coppola mischaracterizes my testimony. The cost of equity is forward-
12 looking; therefore, the inputs to the CAPM analysis, theoretically, should be
13 forward-looking. However, no one knows with certainty what the future risk-free
14 rate will be, despite Mr. Coppola’s belief that the projected risk-free rate “more
15 reliably reflects the trend in interest rates over the coming year.”⁷⁸ In the
16 Company’s last rate case in Case No. U-21534, Mr. Coppola used a projected risk-
17 free rate of 4.05 percent, based on his belief that future cuts to the Federal Reserve’s
18 target Federal Funds rate would result in lower long-term interest rates in 2025.⁷⁹
19 This has not happened. In fact, despite the Federal Reserve’s 100 basis point
20 reduction in the Federal Funds rate late last year, long-term interest rates have
21 increased in 2025 and are approximately 4.90 percent, or 85 basis points above his
22 prediction one year ago.

⁷⁵ Direct Testimony of Jennifer E. Nelson, page 30, lines 10-12.

⁷⁶ Source: Blue Chip Financial Forecasts, Vol. 44, No. 8, August 1, 2025, at 2.

⁷⁷ Direct Testimony of Sebastian Coppola, page 93, lines 10-11.

⁷⁸ Direct Testimony of Sebastian Coppola, page 94, lines 9-11.

⁷⁹ Case No. U-21534, Direct Testimony of Sebastian Coppola, page 92, lines 7-18.

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1 Because current and projected interest rates are both investor influencing, it is
2 reasonable and prudent to apply both a current risk-free rate and a projected risk-
3 free rate in the CAPM. Recognizing the current uncertainty in the market, I believe
4 it is reasonable to give weight to both current and projected risk-free rates. As Dr.
5 Morin observes with respect to the use of current and projected risk-free rates,

6 *One reasonable option for the regulator is to accord equal weight to*
7 *both current interest rate levels and the analysts' consensus forecast.*
8 *Each proxy for expected interest rates brings information to the*
9 *judgment process from a different light. Neither proxy is without*
10 *blemish, each has advantages and shortcomings.⁸⁰*
11

12 **Q55. What is your response to Mr. Coppola's assertion that there is "no validity"**
13 **to the fact that the market risk premium changes with the risk-free rate?⁸¹**

14 A55. Mr. Coppola is incorrect. Mr. Coppola explains the CAPM formula at pages 88-89
15 of his testimony and accurately describes the market risk premium (denoted as " R_p "
16 in his testimony) as the difference between the overall return of the market less the
17 risk-free rate. Therefore, it is a mathematical fact that the market risk premium is
18 a function of the risk-free rate. Unless Mr. Coppola believes that the overall return
19 on the market moves in lock-step with changes in the risk-free rate (of which he
20 makes no claim, nor provides any support to justify), the market risk premium, by
21 definition, changes as the risk-free rate changes. Since the market risk premium is
22 a function of the risk-free rate, using a constant market risk premium regardless of
23 the risk-free rate understates the market risk premium when the risk-free rate is
24 below the long-term average, and overstates the market risk premium when the
25 risk-free rate is above the long-term average. To avoid overstating or understating
26 the market risk premium, I do not rely on a constant market risk premium like Mr.

⁸⁰ Roger A. Morin, Ph.D., New Regulatory Finance, at 173 (2006).

⁸¹ Direct Testimony of Sebastian Coppola, at page 95, lines 1-2.

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1 Coppola. Instead, I rely on the long-term average historical market return, and
2 calculate the resulting market risk premium as the difference between the return on
3 the market and the risk-free rate estimate, exactly as the CAPM formula prescribes.
4 In fact, academic research has concluded that the market risk premium and the risk-
5 free rate are inversely related; as the risk-free rate increases, the market risk
6 premium decreases, and vice versa.⁸² For example, Harris and Marston found
7 "...strong evidence...that market risk premia change over time and, as a result, use
8 of a constant historical average risk premium is not likely to mirror changes in
9 investor return requirements."⁸³ Among their findings is that the market risk
10 premium is inversely related to government bond yields. Therefore, I continue to
11 believe my CAPM analysis using the long-term average historical market return is
12 properly specified.

13 Moreover, the risk-free rate appears twice in the CAPM formula as shown below:

14
$$\text{ROE} = \text{Risk-Free Rate} + \text{Beta} (\text{Expected Market Return} - \text{Risk-Free Rate})$$

15 Therefore, the risk-free rate that is used in the CAPM and in the market risk
16 premium must be the same, otherwise there is an internal consistency. The risk-
17 free rate implied in Mr. Coppola's market risk premium (7.35 percent) is
18 approximately 4.80 percent,⁸⁴ however, he applies a risk-free rate of 4.46 percent
19 as one risk-free rate, while assuming a higher risk-free rate in his market risk
20 premium. Exhibit A-39, Schedule DD2.11 revises Mr. Coppola's CAPM analysis

⁸² 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.

⁸³ Robert S. Harris and Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, Summer 1992, at 69.

⁸⁴ Kroll Cost of Capital Navigator.

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1 to use the same risk-free rate in both components of the CAPM, which results in an
2 ROE estimate of 10.29 percent.

3

4 **Q56. Please respond to Mr. Coppola's assessment of your projected market risk**
5 **premium.⁸⁵**

6 A56. Mr. Coppola disagrees with my forward market return estimate because (1) it relies
7 on three- to five-year earnings growth rates that he believes are too short-term in
8 nature; and (2) the S&P 500 Index is a market capitalization-weighted index and
9 some companies' growth rates have greater weight in the index.

10

11 **Q57. Does Mr. Coppola rely on "short-term" earnings growth rates in his DCF**
12 **analysis?**

13 A57. Yes, he does. As explained in my direct testimony, my forward market return
14 estimate applies the Constant Growth DCF model to the S&P 500 Index. As noted
15 earlier, I rely on the longest-term earnings growth rate projections that I am aware
16 are available. Mr. Coppola also relies on Value Line's three- to five-year earnings
17 growth rate projections in his DCF analysis, which is the same source I rely on for
18 the forward market return estimate. Furthermore, Mr. Coppola relies on an even
19 shorter one-year growth rate projection from Yahoo. Mr. Coppola's criticism is
20 without merit.

21

22 **Q58. Mr. Coppola asserts that Dr. Morin "strongly supports the use of the longest**
23 **possible period for calculating a market risk premium."⁸⁶ What is your**
24 **response?**

⁸⁵ Direct Testimony of Sebastian Coppola, page 96, lines 14-18; page 97, lines 1-22; page 98, lines 1-8.

⁸⁶ Direct Testimony of Sebastian Coppola, page 97, lines 15-22; page 98, lines 1-3.

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1 A58. Mr. Coppola's testimony incorrectly ascribes Dr. Morin's position on the
2 appropriate *historical* market risk premium methodology to a forward looking
3 market risk premium. On page 116 of his textbook, *New Regulatory Finance*, Dr.
4 Morin explains that while historical return studies over long periods provide a
5 useful guide for the future, "forward-looking risk premiums based on expected
6 returns are preferable."⁸⁷ Further, Dr. Morin recommends that

7 *"a regulatory body should rely on the results of both historical and*
8 *prospective studies in arriving at an appropriate risk premium, data*
9 *permitting. Each proxy for the expected risk premium brings*
10 *information to the judgment process from a different light."*⁸⁸

11 Given that the cost of equity is forward looking, I believe it is reasonable and
12 consistent with investor practice to consider both historical and forward-looking
13 market return estimates.

14

15 **Q59. Mr. Coppola criticizes your Beta coefficients because they are not current.⁸⁹**
16 **Have you updated your CAPM analyses to reflect current Beta coefficients?**

17 A59. Yes, I have. Exhibit A-39, Schedule DD.2.4 presents my updated CAPM analysis
18 with more current Beta coefficients.

19

20 **Q60. Mr. Coppola criticizes the ECAPM, citing Dr. Morin's textbook *New***
21 ***Regulatory Finance* to support his criticism regarding the use of long-term**
22 **risk-free rates in the CAPM.⁹⁰ Has Mr. Coppola accurately cited Dr. Morin's**
23 **position on the ECAPM?**

⁸⁷ Roger A. Morin, Ph.D., *New Regulatory Finance*, at 116 (2006).

⁸⁸ Roger A. Morin, Ph.D., *New Regulatory Finance*, at 163 (2006).

⁸⁹ Direct Testimony of Sebastian Coppola, page 95, lines 7-10; page 96, lines 1-2.

⁹⁰ Direct Testimony of Sebastian Coppola, page 98, lines 19-20; page 99, lines 1-5.

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1 A60. No, Mr. Coppola misquotes Dr. Morin's textbook and takes his discussion of the
2 ECAPM out of context to make it appear as if Dr. Morin disagrees with the use of
3 long-term risk-free rates in the ECAPM. To be clear, Dr. Morin is an advocate of
4 the ECAPM and has presented it before regulatory commissions using a long-term
5 risk-free rate and the same formula I rely on. In his discussion of the use of long-
6 term risk-free rates in the ECAPM, Dr. Morin explains that if long-term risk-free
7 rates are used, a conservative (i.e., lower) alpha adjustment is applied because the
8 long-term risk-free rate partially accounts for the flatter slope. Dr. Morin's full
9 explanation in his textbook New Regulatory Finance that Mr. Coppola
10 mischaracterizes states:

11 *An alpha range of 1 %-2% is somewhat lower than that estimated*
12 *empirically. The use of a lower value for alpha leads to a lower*
13 *estimate of the cost of capital for low-beta stocks such as regulated*
14 *utilities. This is because the use of a long-term risk-free rate rather*
15 *than a short-term risk-free rate already incorporates some of the*
16 *desired effect of using the ECAPM. That is, the long-term risk-free rate*
17 *version of the CAPM has a higher intercept and a flatter slope than the*
18 *short-term risk-free version which has been tested. Thus, it is*
19 *reasonable to apply a conservative alpha adjustment. Moreover, the*
20 *lowering of the tax burden on capital gains and dividend income*
21 *enacted in 2002 may have decreased the required return for taxable*
22 *investors, steepening the slope of the ECAPM risk-return trade-off and*
23 *bring it closer to the CAPM predicted returns.⁹¹*

24 The ECAPM formula that I apply assumes a conservative alpha adjustment in the
25 range of 1 percent to 2 percent, which is consistent with the academic literature and
26 Dr. Morin's recommendation. In other words, my ECAPM accounts for the use of
27 a long-term risk-free rate. Mr. Coppola's characterization of the ECAPM is
28 inaccurate, unsupported, and without merit.

⁹¹ Roger A. Morin, Ph.D., New Regulatory Finance, at 190-191 (2006). Emphasis added.

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1 **Q61. Have regulatory commissions explicitly adopted the ECAPM in recent**
2 **proceedings, contrary to Mr. Coppola's testimony?**

3 A61. Yes. Mr. Coppola ignores the decisions in 2023 by the North Carolina Utilities
4 Commission ("NCUC") for Duke Energy Progress and Duke Energy Carolinas, in
5 which the NCUC explicitly adopted the ECAPM using Dr. Morin's ECAPM
6 formula, including adjusted Beta coefficients that I apply I this proceeding.⁹² Mr.
7 Coppola also ignores the New York Public Service Commission's preference for
8 the ECAPM (also referred to as the zero-Beta CAPM).⁹³

9 Utility Risk Premium Analysis

10 **Q62. Please describe Mr. Coppola's Utility Risk Premium Analysis.**

11 A62. Mr. Coppola calculates a Risk Premium-based ROE estimate of 9.86 percent by
12 adding his 4.25 percent average historical spread of total returns on electric utility
13 stocks, to his 5.61 percent projected "A" rated utility bond yield.⁹⁴ Mr. Coppola's
14 Utility Risk Premium approach is substantially similar to Mr. Ufolla's approach
15 based on Treasury bond yields.
16 My primary concern is that neither Mr. Coppola nor Mr. Ufolla's Utility Risk
17 Premium analyses capture the inverse relationship between bond yields and the
18 equity risk premium. Additionally, neither Mr. Coppola nor Mr. Ufolla consider a

⁹² North Carolina Utilities Commission Docket No. E-7, Sub 1276, *In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation*, Order Accepting Stipulations, Granting Partial Rate Increase, Requiring Public Notice, and Modifying Lincoln Ct CPCN Conditions, at 209-210 (December 15, 2023); North Carolina Utilities Commission Docket No. E-2, Sub 1300, *In the Matter of Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation*, Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Public Notice, at 162-163 (August 18, 2023).

⁹³ See, e.g., New York Public Service Commission, Case 16-G-0058, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of KeySpan Gas East Corporation d/b/a National Grid for Gas Service*, Order Adopting Terms of Joint Proposal and Establishing Gas Rate Plans, December 16, 2016, at 32.

⁹⁴ Direct Testimony of Sebastian Coppola, at page 91, lines 1-8;; Exhibit AG-27.

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1 forward-looking utility risk premium analysis. As discussed in response to Mr.
2 Ufolla, using a forward-looking return on the 32 companies in the S&P 500 Utilities
3 Index produces ROE estimates of approximately 11.50 percent.

4 Additionally, as explained in my response to Mr. Coppola's CAPM analysis, the
5 correct 2026 projection of the 30-year Treasury bond yield is 4.65 percent.
6 Revising Mr. Coppola's Risk Premium analysis to use the correct projected 30-year
7 Treasury bond yield increases his Risk Premium estimate to 10.05 percent (see
8 Exhibit A-39, Schedule DD2.12).

9 **Q63. Does Mr. Coppola accurately describe your Bond Yield Plus Risk Premium**
10 **analysis?**

11 A63. No, he does not. Mr. Coppola appears to misunderstand my Bond Yield Plus Risk
12 Premium analysis and misrepresents it in his testimony. The first error is that Mr.
13 Coppola only references the analysis using projected bond yields and does not
14 reference the fact that I also provide an analysis using a current 30-day average
15 bond yield.⁹⁵ The second error is that he asserts that I conclude that the average
16 risk premium over the 1980 to 2025 period is 5.74%.⁹⁶ The 5.74 percent risk
17 premium is not the average over the 1980 to 2025 period; it is the implied equity
18 risk premium when the bond yield is 4.46 percent, based on the regression
19 coefficients. The third error is Mr. Coppola's incorrect assertion that the analysis
20 "assumes a direct relationship between declining interest rates and ROE decisions
21 as happening almost instantaneously on a monthly basis."⁹⁷ The bond yields used
22 in my analysis are not spot prices and reflect the average bond yield over the

⁹⁵ Direct Testimony of Sebastian Coppola, page 91, lines 16-20; page 92, lines 1-4.

⁹⁶ Direct Testimony of Sebastian Coppola, page 91, lines 19-20; page 92, line 1.

⁹⁷ Direct Testimony of Sebastian Coppola, page 92, lines 14-15.

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1 average length of a rate case, approximately 200 days. This most certainly is not
2 “instantaneous.”

3 Mr. Coppola’s lack of understanding my analysis leads him to erroneously
4 conclude that my analysis is flawed.

5

6 **Q64. What is your response to Mr. Coppola’s claim that “the analysis is biased**
7 **because it covers a period when interest rates declined from 12.1% in late**
8 **1980s to between 4% to 5% in 2025.”⁹⁸**

9 A64. Here again Mr. Coppola fails to understand the analysis and is incorrect. Because
10 the equity risk premium and bond yields are inversely related, the equity risk
11 premium during periods of high interest rates is very low, and vice versa. The
12 objective of the analysis is precisely to model how the equity risk premium changes
13 over a long period of time (more than 1,800 rate cases over 45 years) with respect
14 to various economic and interest rate environments. Therefore, it is not biased; it
15 considers both high and low interest rate environments, using the full history of
16 data available over the last 45 years.

17

18 **Q65. Is Mr. Coppola correct that your Bond Yield Plus Risk Premium analysis “has**
19 **no validity as a tool to determine an appropriate ROE in rate case**
20 **proceedings?”⁹⁹**

21 A65. No, he is not. My Bond Yield Plus Risk Premium analysis is firmly grounded in
22 academic, peer reviewed literature. ABATE Witness Walters also uses a similar
23 analysis based on a regression analysis of the relationship between authorized
24 ROEs and bond yields.

⁹⁸ Direct Testimony of Sebastian Coppola, page 92, lines 11-13.

⁹⁹ Direct Testimony of Sebastian Coppola, page 92, lines 18-19.

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1 Published research has shown that the equity risk premium is not constant, but
2 varies inversely with interest rates. As noted earlier, Harris and Marston concluded
3 that the equity risk premium moves inversely with changes in interest rates.¹⁰⁰
4 Similarly, a study by Maddox, Pippert, and Sullivan, found that their results
5 “indicate a statistically significant inverse relationship between interest rates and
6 utility equity risk premiums.”¹⁰¹ Simply assuming a constant equity risk premium,
7 as Mr. Coppola and Mr. Ufolla do, is inconsistent with published research.

8

9 **Q66. Does your Bond Yield Plus Risk Premium analysis reflect the various factors**
10 **that regulators consider when setting ROEs, including that regulators do not**
11 **adjust ROEs “in lock step with interest rate changes.”¹⁰²**

12 A66. Yes, the model shows that authorized ROEs do not move “in lock step with interest
13 rates.” In fact the equity risk premium moves about 30 to 50 percent of the change
14 in interest rates. As explained in my Direct Testimony, one advantage of the Bond
15 Yield Plus Risk Premium approach is that it adds a measure of stability because it
16 is less vulnerable to changes in market data. As shown in Table 9 of my Direct
17 Testimony, a 36-basis point increase in the bond yield (from 4.46 percent to 4.82
18 percent) results in only a 17-basis point change in the ROE from 10.20 percent to
19 10.37 percent. Thus, I agree that the cost of equity does not move in lock step with
20 changes in interest rates, and it reflects all the various factors that regulators
21 consider in setting authorized ROEs. By incorporating more than 1,800 rate case

¹⁰⁰ Robert S. Harris and Felicia C. Marston, *The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts*, *Journal of Applied Finance*, Vol. 11, No. 1, 2001, at 11-12, 14.

¹⁰¹ 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*, Vol. 24, No. 3, Autumn 1995 at 95.

¹⁰² Direct Testimony of Sebastian Coppola, page 92, lines 15-18.

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1 decisions over the last 45 years, the effect of any company-specific, or jurisdiction-
2 specific factors on the authorized ROE is mitigated.

3

4 **Q67. In response to Mr. Coppola, please explain why authorized ROEs are relevant**
5 **to the cost of equity determination.**

6 A67. As explained in my Direct Testimony, authorized ROEs in other jurisdictions are a
7 significant part of the market information that investors consider when evaluating
8 their investment alternatives. Therefore, they are a direct measure of returns
9 available to other electric utilities, as required under the comparable return standard
10 of the *Hope* and *Bluefield* decisions. Mr. Coppola clearly understands this, which
11 is why he reviews authorized ROEs in other jurisdictions as support for his
12 recommendations in his Exhibit AG-28 and Exhibit AG-29 and on pages 100-101
13 of his direct testimony. It is disingenuous for him to rely on authorized ROEs to
14 support his recommendation on the one hand, yet criticize the relevance of
15 authorized ROEs in the Risk Premium analysis on the other. Mr. Coppola's
16 criticisms lack merit and should be rejected.

17 **Response to ABATE Witness Walters**

18 **Q68. Please summarize Mr. Walters' cost of capital recommendation.**

19 A68. Mr. Walters recommends an ROE range of 9.0 percent to 10.0 percent by reference
20 to: (1) his Constant Growth and Multi-Stage DCF models (with median and average
21 results ranging from 8.36 percent to 10.65 percent);¹⁰³ (2) his Risk Premium study
22 (ranging from 9.87 percent to 10.06 percent);¹⁰⁴ and (3) his CAPM analyses
23 (ranging from 7.18 percent to 10.54 percent).¹⁰⁵ Mr. Walters selects the midpoint
24 of his range and recommends DTE Electric's authorized ROE be set at 9.50

¹⁰³ Direct Testimony of Christopher C. Walters, page 42, Table CCW-7 line 2.

¹⁰⁴ Direct Testimony of Christopher C. Walters, page 48, Table CCW-8 line 13.

¹⁰⁵ Direct Testimony of Christopher C. Walters, page 57, Table CCW-10 line 12.

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1 percent.¹⁰⁶ As noted earlier, Mr. Walters' recommended range overlaps with my
2 recommended ROE range of 9.90 percent to 11.60 percent.

3

4 **Q69. What are the primary issues on which you and Mr. Walters agree?**

5 A69. Mr. Walters and I agree on the following issues: (1) the proxy group of risk
6 comparable companies; (2) the use of the 30-year Treasury yield as the risk-free
7 rate in the CAPM, as well a benchmark bond yield in the Risk Premium analysis;
8 and (3) the use of analysts' projected earnings growth rates in the Constant Growth
9 DCF model. As explained below, however, certain of Mr. Walters' inputs and
10 approaches are flawed, causing him to erroneously conclude that the Company's
11 cost of equity has declined. Small adjustments to Mr. Walters' analyses to correct
12 for these flaws increase his recommended ROE range to 10.07 percent to 10.61
13 percent (midpoint of 10.34 percent).

14 DCF Analysis

15 **Q70. Please summarize Mr. Walter's DCF analyses.**

16 A70. Mr. Walters uses two DCF models, a Constant Growth DCF model (using both
17 analysts' projected earnings growth and sustainable growth rates) and a Multi-Stage
18 DCF ("MSDCF") model. In both analyses, he applies stock price data for the 13-
19 week period ending July 11, 2025. For Mr. Walters' long-term growth rate
20 component in his Analysts' Growth Constant Growth DCF model, he uses three- to
21 five-year projected earnings growth rates from Zacks, S&P Global Market
22 Intelligence ("MI"), and Institutional Brokers' Estimate System ("I/B/E/S") from
23 LSEG Workspace. His Sustainable Growth Constant Growth DCF method applies
24 an estimate of projected retention growth from Value Line.¹⁰⁷ Mr. Walters uses

¹⁰⁶ Direct Testimony of Christopher C. Walters, page 59, lines 2-7.

¹⁰⁷ Direct Testimony of Christopher C. Walters, page 35, lines 6-8.

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1 projected gross domestic product (GDP) growth from Blue Chip as the terminal
2 growth rate in his MSDCF analysis.¹⁰⁸ Using these inputs, he derives DCF-based
3 ROE estimates ranging from 8.59 percent to 10.65 percent for his Constant Growth
4 DCF models, and mean and median results for his MSDCF model of 8.53 percent
5 and of 8.36 percent, respectively.¹⁰⁹

6

7 **Q71. Do you have any concerns with Mr. Walters' DCF analyses?**

8 A71. Yes. I disagree with the application of Mr. Walters' sustainable growth and
9 MSDCF analyses.

10

11 **Q72. Turning first to Mr. Walters' MSDCF model, do you agree with Mr. Walters'**
12 **position that utility earnings growth rates applied in the DCF model are**
13 **limited by forecasted Gross Domestic Product ("GDP") growth?**

14 A72. No, I do not. Mr. Walters' MSDCF analysis is premised on the assumption that
15 analysts' projected EPS growth rates are "unsustainable" because a utility stock
16 cannot grow at a faster pace than the growth in the overall economy.¹¹⁰ Therefore,
17 he concludes that the projected national GDP growth rate is the maximum long-
18 term sustainable growth rate, which he applies as the terminal growth rate in his
19 MSDCF analysis. As discussed below, the premise that utility earnings growth is
20 constrained by the U.S. GDP growth rate has not proven true. Therefore, Mr.
21 Walters' MSDCF results should be given no weight.

22

23 **Q73. As a preliminary matter, what is the primary driver of utility earnings?**

¹⁰⁸ Direct Testimony of Christopher C. Walters, page 39, lines 3-7.

¹⁰⁹ Direct Testimony of Christopher C. Walters, page 42, Table CCW-7 line 2.

¹¹⁰ Direct Testimony of Christopher C. Walters, page 33 lines 21-22 and 34 lines 1-6.

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1 A73. As Mr. Walters correctly observes, utility earnings and dividend growth are
2 primarily driven by rate base growth.¹¹¹ Using utility capital expenditures as a
3 proxy for rate base, Mr. Walters' own data shows that rate base growth has
4 outpaced U.S. GDP growth over the last decade.¹¹² Further, growth in rate base
5 growth has exceeded the analyst earnings growth rate projections Mr. Walters and
6 I rely on. Consequently, the analyst projected earnings growth rates we apply in
7 our Constant Growth DCF analyses are not overstated.

8

9 **Q74. Please further describe the growth in utility capital expenditures over the last**
10 **decade.**

11 A74. In his Figure CCW-2, Mr. Walters graphs utility capital expenditures using annual
12 utility capital expenditure data reported by RRA. According to Mr. Walters' data
13 in Figure CCW-2, capital expenditures for the electric and natural gas utilities have
14 grown at a compound annual rate of approximately 7.6 percent per year over the
15 last decade (2014-2024). The compound annual growth rate over the last three and
16 five years (10.5 percent per year and 7.2 percent per year, respectively) is highly
17 consistent with the decade's compound annual growth rate.¹¹³ As shown in Table
18 7 below, the compound annual growth rate in the proxy group's capital
19 expenditures is similar to the overall utility sector's growth.

¹¹¹ Direct Testimony of Christopher C. Walters, page 37, lines 12-19.

¹¹² I recognize that accumulated depreciation is deducted from rate base. However, as the RRA report on utility capital expenditures (the source of Mr. Walters' Figure CCW-2) shows, the ratio of capital expenditures to depreciation and amortization has been above 2.0x for at least the last decade. In other words, new capital additions to rate base have exceeded depreciation and amortization by more than double.

¹¹³ Source: Mr. Walters' CCW Confidential WP 5.

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1 **Table 7 Compound Annual Growth in Capital Expenditures (2014-2024)¹¹⁴**

	3-yr CAGR (2021-2024)	5-yr CAGR (2019-2024)	10-yr CAGR (2014-2024)
DTE Electric Proxy Group	12.76%	7.45%	8.18%
Total Electric Utility Sector	10.53%	7.19%	7.54%

2 The proxy group average projected earnings growth rates used in my and Mr.
3 Walters' Constant Growth DCF analyses (6.43 percent and 6.67 percent,
4 respectively) are lower than growth rates in utility capital expenditures, and
5 therefore are not overstated. Rather, they are highly consistent with the rate base
6 growth, as would be expected. Moreover, these growth rates are higher than
7 historical and projected GDP growth, which indicates that utility growth is not
8 constrained by economic growth at the national level.

9 Although Mr. Walters suggests that current analyst earnings growth projections are
10 unsustainably high under the presumption that growth in rate base will subside as
11 utility investment cycles slow down, compound annual growth in utility capital
12 expenditures has been in the range of approximately 7 percent per year for the last
13 15 years.¹¹⁵ Given the substantial amount of capital that is expected to be invested
14 to meet growing demand, improve reliability, and harden the system against more
15 volatile weather, it is unlikely that electric utilities are nearing the end of their
16 investment cycles; rather it is likely the beginning. Mr. Walters acknowledges that
17 "capital investments for the utility industry continue to stay at elevated levels, and

¹¹⁴ Source: Mr. Walters' CCW Confidential WP 5, S&P Global Market Intelligence, *RRA Financial Focus: Utility Capex Capital Expenditures Update H1 2025: 2014-29f*, March 24, 2025.

¹¹⁵ See, RRA Financial Focus, "Utility Capital Expenditures update: H2'21: 2010-2025E" and corresponding Excel data tables published November 30, 2021.

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1 these investments for capital expenditures are expected to fuel utilities' profit
2 growth *into the foreseeable future.*"¹¹⁶ Therefore, Mr. Walters' own data shows
3 that the primary driver of utility earnings growth is not expected to be constrained
4 by U.S. GDP growth.

5 **Q75. Is there additional evidence to support the position that utility growth is not**
6 **limited by GDP growth?**

7 A75. Yes. GDP is the sum of all private industry and government output in the United
8 States, and the GDP growth rate is an approximate average of the value of those
9 industries. As such, some sectors will grow faster than the average, and some will
10 grow slower. Since 1947, the utility sector as a component of GDP has grown at a
11 faster compound average annual rate (6.47 percent) than the overall GDP growth
12 rate (6.38 percent).¹¹⁷ Here again, Mr. Walters' premise that GDP growth is an
13 upper limit on an individual utility company's growth or the utility sector's growth
14 expectations is unproven. Notably, the earnings growth rate projections included in
15 my and Mr. Walters' DCF analyses are consistent with the long-term historical
16 compound annual GDP growth rate for the utility sector. From that perspective,
17 the projected EPS growth rates in our respective Constant Growth DCF analyses
18 are not excessive.

19
20 **Q76. Are there concerns with relying on a single, universal growth rate as the**
21 **terminal growth rate in the MSDCF model?**

22 A76. Yes. Specifically, the use of a single generic terminal growth rate for each proxy
23 company (such as Mr. Walters' 4.09 percent GDP growth rate) fails to consider the
24 unique prospects and growth expectations of each individual company. As

¹¹⁶ Direct Testimony of Christopher C. Walters, page 8 lines 5-8. (italics added)

¹¹⁷ Source: U.S. Bureau of Economic Analysis.

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1 discussed earlier, it is difficult to reconcile Mr. Walters' position that the driver of
2 utilities' earnings growth (i.e., rate base growth) is expected to remain elevated and
3 drive utility earnings for "the foreseeable future"¹¹⁸ with his presumption that
4 earnings growth will decline by almost half over the next five to 10 years. Despite
5 this internal inconsistency in his MSDCF analysis, Mr. Walters gives more weight
6 to his MSDCF and sustainable growth rate DCF results than his Constant Growth
7 DCF results using analysts growth rates.¹¹⁹

8

9 **Q77. Turning now to the Sustainable Growth DCF model, please describe your**
10 **concern with sustainable growth application of the Constant Growth DCF**
11 **model.**

12 A77. The sustainable growth rate (or retention growth rate) calculation assumes that
13 future earnings will increase as the retention ratio increases. However, this
14 relationship may not hold for a given company based on management decisions
15 associated with the dividend payout rate. This conclusion is supported by two
16 articles published in the Financial Analysts Journal that discussed the theory that
17 high dividend payouts (i.e., low retention ratios) are associated with low future
18 earnings growth.¹²⁰ Each of those articles cited a 2003 study by Arnott and
19 Asness¹²¹ that found, over the course of 130 years of data, future earnings growth
20 is associated with high, rather than low payout ratios.¹²² Specifically, Arnott and
21 Asness concluded:

¹¹⁸ Direct Testimony of Christopher C. Walters, page 8, line 8.

¹¹⁹ Direct Testimony of Christopher C. Walters, page 41, lines 21-22 and page 42, lines 1-2.

¹²⁰ Ping Zhou, William Ruland, *Dividend Payout and Future Earnings Growth*, Financial Analysts Journal, Vol. 62, No. 3, 2006. See also Owain ap Gwilym, James Seaton, Karina Suddason, Stephen Thomas, *International Evidence on the Payout Ratio, Earnings, Dividends and Returns*, Financial Analysts Journal, Vol. 62, No. 1, 2006.

¹²¹ Robert Arnott, Clifford Asness, *Surprise: Higher Dividends = Higher Earnings Growth*, Financial Analysts Journal, Vol. 59, No. 1, January/February 2003.

¹²² Since the payout ratio is the inverse of the retention ratio, the authors found that future earnings growth is negatively related to the retention ratio.

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1 *Unlike optimistic new-paradigm advocates, we found that low payout*
 2 *ratios (high retention rates) historically precede low earnings growth.*
 3 *This relationship is statistically strong and robust. We found that the*
 4 *empirical facts conform to a world in which managers possess private*
 5 *information that causes them to pay out a large share of earnings when*
 6 *they are optimistic that dividend cuts will not be necessary and to pay*
 7 *out a small share when they are pessimistic, perhaps so that they can*
 8 *be confident of maintaining the dividend payouts. Alternatively, the*
 9 *facts also fit a world in which low payout ratios lead to, or come with,*
 10 *inefficient empire building and the funding of less than-ideal projects*
 11 *and investments, leading to poor subsequent growth, whereas high*
 12 *payout ratios lead to more carefully chosen projects. The empire-*
 13 *building story also fits the initial macroeconomic evidence quite well.*
 14 *At this point, these explanations are conjectures; more work on*
 15 *discriminating among competing stories is appropriate.¹²³*

16 Given that all three studies found that there is a negative relationship between
 17 earnings growth and retention ratios, the theory underlying Mr. Walters'
 18 sustainable growth rates in the DCF model do not hold and his results should be
 19 dismissed.

20 Moreover, the sustainable growth model requires the analyst to estimate four
 21 separate variables rather than relying on a single estimate of projected growth. The
 22 result is that the potential for bias and error increases as the analyst must assess and
 23 estimate four inputs rather than one. As Dr. Roger Morin explains:

24 *There are three problems in the practical application of the*
 25 *sustainable growth method. The first is that it may be even more*
 26 *difficult to estimate what b , r , s , and v , investors have in mind than*
 27 *it is to estimate what g they envisage. It would appear far more*
 28 *economical and expeditious to use available growth forecasts and*
 29 *obtain g directly instead of relying on four individual forecasts of*
 30 *the determinants of such growth. It seems only logical that the*
 31 *measurement and forecasting errors inherent in using four different*

¹²³ Robert Arnott, Clifford Asness, *Surprise: Higher Dividends = Higher Earnings Growth*, Financial Analysts Journal, Vol. 59, No. 1, January/February 2003.

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variables to predict growth far exceed the forecasting error inherent in a direct forecast of growth itself.¹²⁴

Further, the retention growth approach is circular as it requires an estimate of the return on equity (“r”) and is subject to internal inconsistency if the return on equity assumed in the retention growth model differs than the ROE being recommended, as Mr. Walters has assumed. As shown on page 1 of Exhibit AB-15, Mr. Walters assumes an average ROE of 11.45 percent for the proxy group in his sustainable growth DCF analysis, far above his 9.50 percent ROE recommendation for DTE Electric. Additionally, Dr. Morin notes that the empirical financial literature demonstrates that the retention growth methodology is not strongly correlated to measures of stock value, such as stock prices and price/earnings ratios. Dr. Morin concludes that the retention growth method is the “weakest” of the three common measures of growth applied in the DCF model “on both conceptual and empirical grounds.”

Lastly, ROE estimates of 8.59 percent to 9.00 percent are in the bottom 0.3 percent of ROEs authorized for vertically integrated electric utilities over more than 45 years and therefore do not meet the *Hope* and *Bluefield* standards for a fair return.

Q78. Mr. Walters cites a 1989 study published in the Journal of Portfolio Management (“JPM”) in support of the use of analyst projected growth rates in the DCF model.¹²⁵ Does this study conclude that sustainable growth rates are better predictors of future returns than analyst earnings growth rates in the DCF model?

¹²⁴ Roger A. Morin, Ph.D., New Regulatory Finance, Public Utility Reports, Inc., at 306 (2006).
¹²⁵ Direct Testimony of Christopher C. Walters, page 32, footnote 13.

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1 A78. No, it does not. As explained in my direct testimony, the appropriate growth rate
2 applied in the DCF model is investors' growth expectation embodied in the
3 valuation of the firm (i.e., stock price appreciation). The 1989 Journal of Portfolio
4 Management (JPM) study by Myron Gordon, et.al, concluded that analysts'
5 earnings growth forecasts were better predictors of returns for public utility stocks
6 than were historical earnings growth rates, historical dividend growth rates, and
7 sustainable (or retention) growth rates.¹²⁶ Therefore, the study that Mr. Walters
8 relies on does not support the position that sustainable growth rates are reliable
9 predictors of utility stock valuations.

10

11 **Q79. Are there other indicators that investors are primarily concerned with**
12 **earnings growth (and not sustainable growth) when making investment**
13 **decisions?**

14 A79. Yes. In addition to the studies supporting the use of analysts' projected earnings
15 growth rates in the DCF model, when providing guidance to investors regarding
16 the total return targets in their investor presentations, companies tend to define the
17 total return as the dividend yield plus earnings growth, not dividend, book value,
18 or sustainable growth estimates.¹²⁷ This demonstrates that companies recognize
19 investors are most concerned with earnings growth when making investment
20 decisions. For these reasons, analysts' projected earnings growth rates are the
21 appropriate growth estimate to apply in the DCF model.

¹²⁶ David Gordon, Myron Gordon, and Lawrence Gould, *Choice Among Methods of Estimating Share Yield*, The Journal of Portfolio Management, Spring 1989 (filed as Mr. Walters' "CCW Confidential WP 20").

¹²⁷ See e.g., American Electric Power Company, Inc., July 30, 2025 Investor Presentation, at 4; CMS Energy, Q2 2025 Investor Presentation, at 3; Duke Energy Corporation, Q2 2025 Earnings Review and Business Update, at 11; Xcel Energy, August 2025 Investor Presentation, at 6.

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1 **Q80. Mr. Walters asserts that your Constant Growth DCF results are based on**
2 **“unsustainably high growth rates.”¹²⁸ What is your response?**

3 A80. As explained earlier, Mr. Walters’ position that the proxy group’s growth is
4 constrained by his estimate of GDP growth is without merit. The primary driver of
5 earnings growth (i.e., rate base growth) has grown at a compound annual average
6 rate of 7 to 8 percent per year for at least the last decade or longer. The proxy group
7 average “high” growth rate of 7.07 percent that Mr. Walters is concerned with is
8 below the compound annual average growth in rate base over the last decade.
9 Therefore, the analyst earnings growth rates in my DCF analyses are not
10 unsustainably high.
11

12 **Q81. Mr. Walters criticizes your Quarterly Growth DCF analysis asserting it**
13 **“overstates” the fair rate of return.¹²⁹ What is your response?**

14 A81. The Quarterly Growth DCF model simply is a refinement of the Constant Growth
15 DCF model. As noted in my Direct Testimony, rather than assuming annual cash
16 flows, the model incorporates investors’ expectations of quarterly dividends,
17 reinvested at the investor-required ROE.¹³⁰ In that regard, the Quarterly DCF
18 model is not fundamentally different than the annual form of the model (on which
19 Mr. Walters relies); both assume that cash flows are reinvested at the required rate
20 of return. The only difference, then, relates to the timing of the cash flows.

21
22 Since utilities pay dividends on a quarterly basis, it is more consistent with the DCF
23 model’s fundamental structure to use the Quarterly DCF model to estimate the

¹²⁸ Direct Testimony of Christopher C. Walters, page 61, lines 1-2.

¹²⁹ Direct Testimony of Christopher C. Walters, page 61, lines 3-4.

¹³⁰ Direct Testimony of Jennifer E. Nelson, page 26, lines 19-21 and page 27, lines 1-5.

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1 market-required cost of equity.¹³¹ The stock prices paid by investors (an input in
2 both the Constant Growth and Quarterly Growth DCF models) assume the quarterly
3 timing of dividend payments; therefore, a proper DCF-based cost of equity estimate
4 must also reflect the actual timing of quarterly dividends. As Dr. Roger Morin
5 explains:

6 *Clearly, given that dividends are paid quarterly and that the observed*
7 *stock price reflects the quarterly nature of dividend payments, the*
8 *market-required return must recognize quarterly compounding, for the*
9 *investor receives dividend checks and reinvests the proceeds on a*
10 *quarterly schedule... The annual DCF model inherently understates the*
11 *investors' true return because it assumes all cash flows received by*
12 *investors are paid annually.*¹³²

13 As explained in my Direct Testimony, although the half-year dividend growth
14 adjustment applied in the Constant Growth DCF analysis is meant to approximate
15 the payment of quarterly dividends, it is a conservative, simplifying assumption
16 that does not fully reflect the quarterly receipt and reinvestment of dividends.¹³³ As
17 such, it underestimates the cost of equity for quarterly dividend paying companies
18 such as utilities. Mr. Walters' position is incorrect and should be rejected.

19 **Q82. What is your recommendation regarding Mr. Walters' DCF estimates?**

20 A82. The underlying premises of Mr. Walters' Constant Growth DCF analysis using
21 sustainable growth rates and his MSDCF analysis do not hold and are unsupported
22 by his own evidence and academic studies. Therefore, I recommend that the
23 Commission give no weight to these results.

¹³¹ Direct Testimony of Jennifer E. Nelson, page 26, lines 11-22 and page 27, lines 1-5.

¹³² Roger A. Morin, Ph.D., *New Regulatory Finance*, Public Utility Reports, Inc., page 344 (2006).

¹³³ Direct Testimony of Jennifer E. Nelson, page 26, lines 11-20. I note that Mr. Walters' Constant Growth DCF analysis includes a full growth rate adjustment, rather than my half growth rate adjustment, which produces results, similar to my updated Quarterly Growth DCF results.

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1 Risk Premium Analysis

2 **Q83. Please describe Mr. Walters' Risk Premium approach.**

3 A83. Mr. Walters develops three Risk Premium-based approaches. All three approaches
4 are based on his calculation of the risk premium as the difference between the
5 average annual authorized equity returns for electric utilities and a measure of long-
6 term bond yields for each year between 1986 and March 2025.¹³⁴ Mr. Walters' first
7 approach to estimating the Risk Premium looks to the 30-year Treasury yield, and
8 his second approach considers A-rated utility bond yields.¹³⁵
9 In developing his risk premium estimates, Mr. Walters reviews annual risk
10 premiums as well as risk premiums over five-year and ten-year rolling averages.
11 He ultimately relies on the annual average risk premium of 5.32 percent from 2023-
12 2025. Combining this average risk premium estimates with a projected 30-year
13 Treasury bond yield of 4.60 percent from Blue Chip produces an ROE estimate of
14 9.92 percent.¹³⁶
15 Using the same approach for his utility bond yield analysis, Mr. Walters calculates
16 annual risk premiums, as well as risk premiums over five-year and ten-year rolling
17 averages and again relies on the annual average equity risk premium (ERP) from
18 2023-2025 of 4.10 percent over A-rated utility bond yields. Combining the 4.10
19 percent average risk premium estimate with the 3-month and 6-month average A-

¹³⁴ Direct Testimony of Christopher C. Walters, page 42, lines 5-15; page 43, lines 1-2; and page 47, lines 2-12.

¹³⁵ Direct Testimony of Christopher C. Walters, page 42, lines 12-13.

¹³⁶ Direct Testimony of Christopher C. Walters, page 45, lines 2-3.

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1 rated utility bond yields through June 2025, Mr. Walters calculates ROE estimates
2 of 9.97 percent to 10.06 percent.¹³⁷

3 Lastly, Mr. Walters performs a third Risk Premium analysis that uses a Weighted
4 Least Squares (“WLS”) regression instead of an Ordinary Least Squares (“OLS”) regression using the same authorized ROEs, long-term Treasury bond yields, and
5 corresponding equity risk premia since 1986. Mr. Walters’ WLS approach gives
6 more weight to more recent annual bond yields and equity risk premia (within the
7 last 5-10 years) and less weight to older annual observations.¹³⁸

9 **Q84. What are your concerns with Mr. Walters’ Risk Premium analyses?**

10 A84. Mr. Walters’ method understates the required risk premium in the current market
11 because it fails to adequately reflect the inverse relationship between the Equity
12 Risk Premium and bond yields. Figure 5 and Figure 6, below, demonstrate a clear
13 inverse relationship between Mr. Walters’ risk premium and bond yield data. By
14 ignoring this statistically significant relationship and instead substituting his own
15 judgment, Mr. Walters’ average risk premium from 1986 to 2025 understates the
16 appropriate risk premium with his projected 30-year Treasury bond yield and utility
17 bond yields. Research has shown that the equity risk premium is inversely related
18 to interest rates.¹³⁹ That is, as interest rates decline, the equity risk premium will
19 increase, not just for utilities but for equity investments broadly. As expected, Mr.

¹³⁷ Direct Testimony of Christopher C. Walters, page 45, lines 2-5 and page 48, Table CCW-8; Exhibit AB-22, page 1.

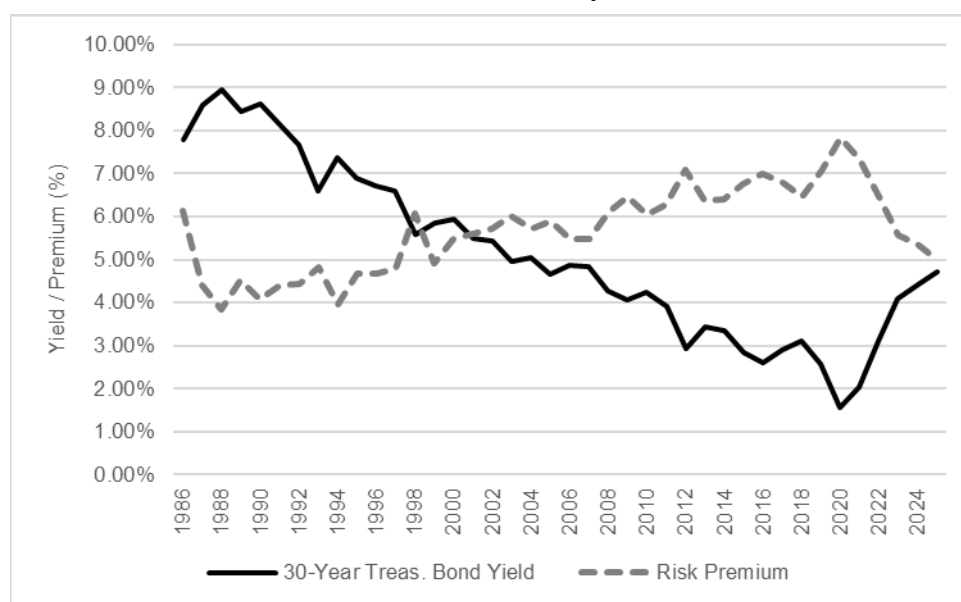
¹³⁸ Direct Testimony of Christopher C. Walters, page 45, lines 12-22 and page 46, lines 1-19.

¹³⁹ 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.

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Walters' data in Exhibits AB-19 and AB-20 demonstrates that there is a statistically significant negative relationship between bond yields and the estimated risk premium.¹⁴⁰ The R-squared is 0.82 to 0.85, which means that interest rates explain 82 to 85 percent of the change in the Risk Premium for authorized electric utility ROEs.

Figure 5 Mr. Walters' Treasury Bond Yield-Based Risk Premium Analysis¹⁴¹



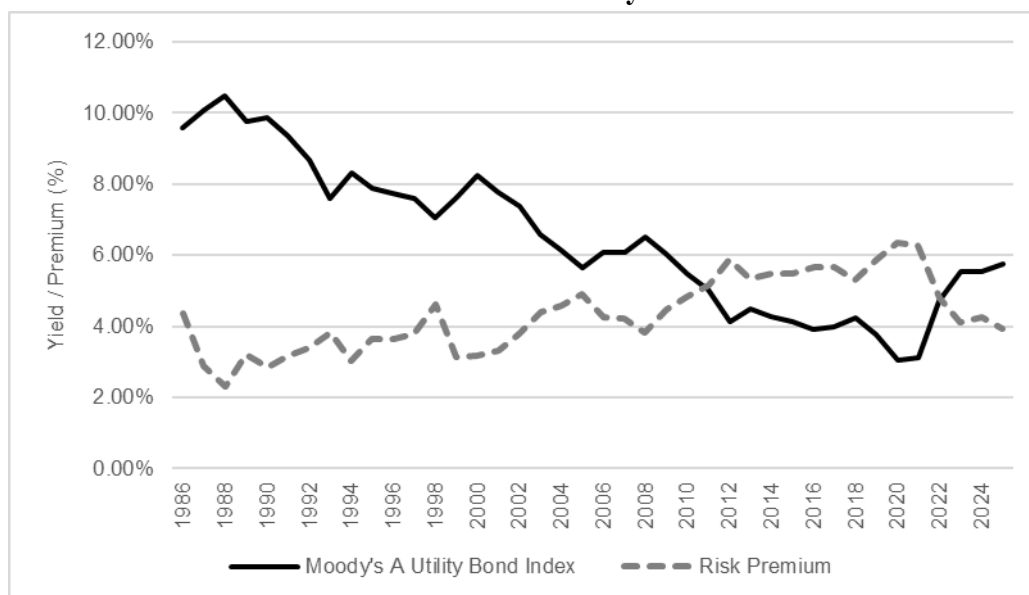
¹⁴⁰ See Exhibit A-39 Schedule DD2.13-2-14, at 2 and 4 which provides a summary of regression statistics demonstrating that the relationship between the interest rate and risk premium data provided by Mr. Walters's Exhibits AB-19 and AB-20 is significant at the 99 percent confidence interval.

¹⁴¹ Source: Walters Exhibit AB-19.

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Figure 6 Mr. Walters' Utility Bond Yield-Based Risk Premium

Analysis¹⁴²



Despite acknowledging the statistical relationship in his WLS regression analysis, Mr. Walters disregards this statistically significant relationship from his other two Risk Premium analysis. Therefore, I have recreated this statistical analysis for his Treasury and Utility bond Risk Premium analyses. Table 8 below summarizes the results and compares them to Mr. Walters' filed analyses, demonstrating that his filed analyses understate the cost of equity by approximately 50-60 basis points.

¹⁴²

Source: Walters Exhibit AB-20.

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1 **Table 8 Mr. Walters’ Risk Premium ROE Using Statistical Modeling¹⁴³**

Description	Yield	As Filed Risk Premium	As Filed ROE	Adjusted Risk Premium	Adjusted ROE
Projected Treasury Yield	4.60%	5.32%	9.92%	5.92%	10.52%
3-month A-Rated Utility	5.96%	4.10%	10.06%	4.57%	10.53%
6-month A-Rated Utility	5.87%	4.10%	9.97%	4.62%	10.48%
Projected A-Rated Utility	5.96%	n/a	n/a	4.57%	10.53%
Average					10.52%

2

3 **Q85. Turning to Mr. Walters’ WLS regression analysis, is a WLS regression**
4 **necessary or appropriate?**

5 A85. No. There are three issues with Mr. Walters’ WLS regression analysis. The
6 primary issue is that Mr. Walters is attempting to solve a problem that doesn’t exist.
7 WLS regressions are used to correct for heteroskedasticity, a statistical problem
8 where the error terms are correlated and have a distinct pattern. Ordinary Least
9 Squares (“OLS”) regressions assume that the error terms are random and
10 independent. I ran an OLS regression on Mr. Walters’ risk premium data and then
11 checked for heteroskedasticity in the error terms using both the Breusch-Pagan test
12 and the White Test. The results of those tests demonstrate there is no pattern in the
13 error terms of Mr. Walters’ OLS regression; thus the error terms are uncorrelated.
14 Therefore, Mr. Walters’ WLS regression is unnecessary. Second, even if Mr.
15 Walters WLS analysis was necessary, he provides no statistical basis for his lambda
16 coefficient of 0.20 that was chosen arbitrarily.
17 Third, by giving more weight to the most recent 5-10 years,¹⁴⁴ Mr. Walters is giving
18 more weight to data that occurred during years when the government implemented

¹⁴³ Exhibit A-39, Schedule DD2.13 and Schedule DD2.14. Numbers may not add due to rounding.
¹⁴⁴ Direct Testimony of Christopher C. Walters, page 47, lines 2-8.

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1 extraordinary monetary and fiscal policy to support the U.S economy during the
2 slow recovery of the Great Recession and the COVID-19 pandemic. The current
3 market environment is vastly different with interest rates at levels not seen in
4 approximately 15 years. Further, monetary policy is currently relatively restrictive,
5 unlike the seven or eight years of zero percent Federal Funds rate and Quantitative
6 Easting between 2009-2015 and 2020-2021. Thus, Mr. Walters biases his analysis
7 by choosing to give less weight to data that better reflect current market
8 environment. This analysis should be rejected.

9

10 **Q86. Mr. Walters asserts that the regression study used in your Bond Yield Plus**
11 **Risk Premium Analysis is less accurate than his WLS analysis.¹⁴⁵ What is your**
12 **response?**

13 A86. I disagree. First, Mr. Walters defines accuracy by comparing the the R-square
14 coefficients, concluding that because his WLS regression produces a higher R-
15 square coefficient, it is “more accurate.” However, the R-square is not always a
16 good measure of accuracy and the goal of a statistical model should not be to
17 maximize the R-square as this could lead to questionable modeling assumptions
18 and inputs. For example, the R-square can be increased by simply adding more
19 independent variables, even if they are unrelated to the dependent variable. As
20 noted earlier, Mr. Walters’ WLS is used to correct for heteroskedasticity, which is
21 not present in his data. A 1988 essay in American Statistician titled “Another
22 Cautionary Note About R^2 : Its Use in Weighted
23 Least-Squares Regression Analysis” explains:

¹⁴⁵ Direct Testimony of Christopher C. Walters, page 73, lines 12-23 and page 74, lines 1-13.

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1 *Weighted least-squares regression analysis minimizes the sum of*
 2 *squared residuals (and therefore maximizes the coefficient of*
 3 *determination) with respect to the transformed variables, whereas OLS*
 4 *regression analysis minimizes the sum of squared residuals (and*
 5 *maximizes the coefficient of determination) with respect to the original*
 6 *variables. Providing that the weighting scheme has been chosen*
 7 *appropriately to counteract the heteroscedastic nature of the random*
 8 *errors, a better fit will be achieved by WLS in the transformed world.*
 9 *Thus the coefficient of determination obtained unthinkingly from a*
 10 *statistical computer package under WLS regression is frequently much*
 11 *larger than the value obtained under the corresponding OLS fit. To the*
 12 *naïve consumer of computer output, this apparent increment to the*
 13 *coefficient of determination can represent a considerable improvement*
 14 *in fit and is displayed prominently in any account of the analysis,*
 15 *whereas closer inspection reveals that the increment reflects, in part, the*
 16 *success of the weighting in solving the problem of heteroscedasticity* ¹⁴⁶

17 The R-square in the WLS regression is the coefficient for the *transformed* dataset.

18 It does not improve the R-square for the original dataset. As explained above,

19 heteroskedasticity is not present in Mr. Walters' data; therefore the higher R-square

20 is providing false confidence that his WLS regression is "more accurate."

21 **Q87. Mr. Walters' also asserts that "statistical noise" in your Bond Yield Plus Risk**
 22 **Premium analysis weakens the analysis.**¹⁴⁷ **Do you agree?**

23 A87. No, I do not. First, as explained earlier, Mr. Walters' comparison of the R-square
 24 coefficients in our analyses is not a meaningful or relevant measure of accuracy,
 25 particularly because his WLS regression is attempting to correct a problem that
 26 doesn't exist. The purpose of my analysis is to model the relationship between the
 27 change in the Treasury bond yield and the change in the equity risk premium. I do
 28 not assert that changes in Treasury bond yields are the only variable that explains
 29 the change in the equity risk premium; however, my model demonstrates that

¹⁴⁶ John B. Willett and Judith D. Singer, "Another Cautionary Note About R^2 : Its Use in Weighted Least-Squares Regression Analysis," The American Statistician, Vol. 42, No. 3, August 1988, at 237 (emphasis in original).

¹⁴⁷ Direct Testimony of Christopher C. Walters, page 73, lines 12-15.

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1 changes in Treasury bond yields explain a large majority of the change in the
2 equity risk premium.
3 Nevertheless, to the extent there is a statistical problem in my analysis, I ran an
4 OLS regression model on the Treasury bond yield and equity risk premium data
5 filed in Exhibit A-14, Schedule D5.5 using heteroskedastic 2 (“HC2”) robust
6 standard errors to correct for any potential problem. After correcting for HC2
7 robust standard errors, the regression formula remains the same as was filed in my
8 direct testimony ($Y = -0.021 - 0.0252X$) and the R-square remains at 0.77. Thus,
9 there is no bias in my Bond Yield Plus Risk Premium analysis.

10 CAPM Analysis

11 **Q88. Please summarize Mr. Walters’ CAPM analysis and results.**

12 A88. Mr. Walters’ CAPM analysis combines three estimates of the market risk premium
13 (“MRP”) and four estimates of the Beta coefficient, along with his projected risk-
14 free rate of 4.60 percent from Blue Chip Financial Forecasts or 4.89 percent based
15 on the current 20-year Treasury yield (applied in his Kroll Normalized Method
16 MRP estimate). Mr. Walters calculates 1212 CAPM estimates, summarized in
17 Table 9 below.

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Table 9 Mr. Walters' CAPM Results, As Filed¹⁴⁸

Market Risk Premium Description	Current <i>Value Line</i> Beta (0.78)	Historical <i>Value Line</i> Beta (0.78)	S&P Beta (0.42)	3-Year Beta (0.65)
Kroll Normalized Method	9.19%	9.20%	7.18%	8.49%
Risk Premium Method	10.06%	10.08%	7.51%	9.17%
FERC DCF Method	10.53%	10.54%	7.76%	9.56%

2

3 **Q89. Are ROE estimates ranging from 7.18 percent to 8.49 percent reasonable?**

4 A89. No. No regulatory commission that I am aware of has authorized an ROE of 8.49
5 percent or lower for a vertically integrated electric utility since 1980.¹⁴⁹ Such
6 results are far below any reasonable estimate of DTE Electric's cost of equity and
7 should be dismissed.

8

9 **Q90. Mr. Walters expresses concerns for using projected 30-Year Treasury Yields**
10 **for five to 10 years out.¹⁵⁰ What is your response?**

11 A90. I disagree. Mr. Walters recommends that "the CAPM and risk premium
12 methodology should be based on observable bond yields in the market today,"¹⁵¹
13 which is exactly the approach I take by considering both current and projected bond
14 yields. Mr. Walters, however, only relies on a projected bond yield.¹⁵² The
15 projected risk-free rate I use gives 50 percent weight to the near-term forecast over
16 the next six quarters from *Blue Chip Financial Forecasts* and 50 percent weight to

¹⁴⁸ Direct Testimony of Christopher C. Walters, page 57, Table CCW-10. See also, Exhibit AB-24, page 1.

¹⁴⁹ Excludes ROEs set for Green Mountain Power in which the ROE is determined formulaically by changes in the 10-year Treasury bond yield.

¹⁵⁰ Direct Testimony of Christopher C. Walters, page 64, lines 5-9.

¹⁵¹ Direct Testimony of Christopher C. Walters, page 64, lines 14-16.

¹⁵² Direct Testimony of Christopher C. Walters, page 50, lines 6-9.

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1 the average of the five- and ten-year forecasts; therefore it is not “largely” based on
2 the the five to 1010 year projections. Notably, Mr. Walters’ projected 30-year
3 Treasury bond yield is from the same source (Blue Chip) as my projected risk-free
4 rate. In the end, Mr. Walters concludes he does not take issue with my projected
5 risk-free rate.¹⁵³

6

7 **Q91. What are your specific concerns with Mr. Walters’ CAPM analyses?**

8 A91. I disagree with (1) certain of Mr. Walters’ Beta coefficients, (2) his reliance on
9 Kroll’s normalized market risk premium method, and (3) certain aspects of the
10 FERC DCF market risk premium methodology.

11

12 **Q92. What is your concern with Mr. Walters’ Beta coefficients from S&P?**

13 A92. Mr. Walters’ estimate of the Beta coefficient includes Vasicek-adjusted Beta
14 coefficients from S&P Global Market Intelligence (“MI”) for his proxy companies.
15 As a preliminary matter the results of Mr. Walters’ CAPM analyses using Vasicek-
16 adjusted Beta coefficients range from 7.18 percent to 7.76 percent. Such results are
17 far below any reasonable measure of DTE Electric’s cost of equity and are
18 approximately 110-180 basis points above current utility bond yields and thus
19 would not provide a sufficient premium for taking on the risk of an equity
20 investment. The Commission should reject these CAPM estimates in their entirety.
21 That aside, while I agree MI is a reliable source of utility financial and rate case
22 data, I disagree with Mr. Walters’ position that Beta coefficients calculated using
23 the Vasicek adjustment are “superior” to those calculated using the Blume
24 adjustment.¹⁵⁴ Simply, the conclusion as to which approach is “superior” remains

¹⁵³ Direct Testimony of Christopher C. Walters, page 64, lines 14-18.

¹⁵⁴ Direct Testimony of Christopher C. Walters, page 51, lines 6-16.

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1 open to debate and there is no consensus on that issue. As Duff & Phelps explains,
2 “[w]hether betas tend to move toward market averages or industry averages over
3 time is an issue open to debate.”¹⁵⁵ Moreover, if there was consensus in the
4 financial community that the Vasicek adjustment methodology was “superior” to
5 the Blume adjustment methodology, it would be more widely adopted by well-
6 known investor data resources, such as Value Line and Bloomberg. However, that
7 is not the case. In my experience, the vast majority of Beta coefficients used by
8 ROE witnesses in regulatory proceedings employ the Blume adjustment
9 methodology. I am not aware of any regulatory commission that has accepted the
10 use of Vasicek adjusted Beta coefficients.

11 Further, the Vasicek adjustment methodology requires more inputs and calculations
12 and is more susceptible to subjective judgment than are the Beta coefficients
13 independently reported by Value Line, or other sources such as Bloomberg that use
14 the Blume adjustment methodology. As S&P notes, the Vasicek adjustment
15 “adjusts the raw beta via weights determined by the variance of the individual
16 security versus the variance of a larger sample of comparable companies.” Because
17 S&P’s Beta Generator model allows the analyst to select up to nine companies in
18 the sample group, the size and makeup of the chosen sample group is highly
19 subjective and could substantially affect the results. As a consequence, S&P’s Beta
20 Generator model – and the Vasicek adjustment generally – is susceptible to the size
21 and selection of the comparable group used in the adjustment. Adjusted Beta
22 coefficients from Value Line, however, are widely used, well understood,

¹⁵⁵ Duff & Phelps 2020 Valuation Handbook, pages 5-9.

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1 independently reported, and easily verifiable; therefore, they are not exposed to
2 these criticisms.

3 **Q93. Have other Commissions rejected the use of Vasicek-adjusted Beta**
4 **coefficients?**

5 A93. Yes. The Florida Public Service Commission concluded that the method was
6 subject to bias, noting that the use of MI Beta coefficients “is questionable and
7 subject to analyst bias.”¹⁵⁶ For similar reasons, the North Carolina Utilities
8 Commission also rejected the use of Vasicek adjusted Beta coefficients in its order
9 for Duke Energy Carolinas in Docket No. E-7, Sub 1276.¹⁵⁷
10

11 **Q94. What is your concern with Mr. Walters’ application of 10-year historical Beta**
12 **coefficients?**

13 A94. When an analyst relies on historical data to estimate the forward-looking cost of
14 equity, they are effectively assuming that the estimate is a reasonable expectation
15 of investor and market expectations going forward. By relying on an average of
16 Value Line’s historical 5-year Beta coefficients, Mr. Walters is effectively
17 presuming that the risk profile of the proxy group during these years is reflective
18 of its current and expected risk profile. A concern with Mr. Walters’ approach is
19 that Value Line’s five-year historical Beta coefficients from 2014 reflect data going
20 back to 2009, which would encompass the 2008/2009 recession, and the slow
21 economic recovery experienced in subsequent years. If Mr. Walters’ intent is to

¹⁵⁶ Florida Public Service Commission Docket No. 20220069-GU, *In re: Petition for rate increase by Florida City Gas*, Order No. PSC-2023-0177-FOF-GU, at 43 (June 9, 2023).

¹⁵⁷ North Carolina Utilities Commission Docket No. E-7, Sub 1276, *In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation*, Order Accepting Stipulations, Granting Partial Rate Increase, Requiring Public Notice, And Modifying Lincoln CT CPCN Conditions, at 206 (December 15, 2023).

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1 consider Beta coefficients over a longer historical period to smooth out his
2 perceived short-term aberrations, he could have used the approach he used with his
3 three-year Beta coefficient approach but use a ten-year period rather than three
4 years (adjusted using the Blume adjustment). This approach would avoid including
5 data from 2009-early 2014 that may skew the historical data.

6

7 **Q95. Mr. Walters asserts that your Beta coefficients are stale and excessive because**
8 **they are affected by “market anomalies” triggered at the onset of the COVID-**
9 **19 pandemic.¹⁵⁸ What is your response?**

10 A95. To respond to Mr. Walters’ and Mr. Coppola’s concerns that the Beta coefficients
11 used in my direct testimony are stale, I have updated my CAPM analysis in Exhibit
12 A-39, Schedule DD2.4. Additionally, in response to Mr. Walters, I have also
13 provided a set of CAPM analyses using Beta coefficients from Bloomberg
14 calculated using 10 years of data instead of five years. This provides a longer
15 history and more data observations, thus reducing the weight of the effect of the
16 COVID-19 period. Though the markets during the onset of the COVID-19 period
17 may have been atypical, I do not agree that the data during this time period was
18 necessarily anomalous. Market events that cause utilities to trade closer to the
19 overall market as they did during the early COVID-19 period may occur in the
20 future. Because the Beta coefficient should reflect the potential for future events
21 to occur, I do not believe it is appropriate to remove those data points from the Beta
22 coefficient as Mr. Walters proposes in his three year average Value Line Betas.¹⁵⁹
23 A better approach is to give those data points less weight in the calculation as the
24 10-year Beta coefficient estimates do. I note that the proxy group average 10-year

¹⁵⁸ Direct Testimony of Christopher C. Walters, page 68, lines 3-8.

¹⁵⁹ Direct Testimony of Christopher C. Walters, page 50, lines 11-22 and page 51, lines 1-23.

Line
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1 Beta coefficients (0.75) are similar to Mr. Walters current and historical average
2 Value Line Beta coefficient (0.78).

3

4 **Q96. Mr. Walters notes that there is an error in your Beta coefficients filed in**
5 **Exhibit A-14, Schedule D5.4.¹⁶⁰ Have you provided a corrected CAPM**
6 **analysis?**

7 A96. Yes. A corrected version of my CAPM analysis filed in my direct testimony is
8 provided as Exhibit A-39, Schedule DD2.6. The results of corrected CAPM
9 analysis did not meaningfully change from the results shown in Exhibit A-14,
10 Schedule D5.4.

11

12 **Q97. Do you agree with Mr. Walters' reliance on Kroll's normalized market risk**
13 **premium method?**

14 A97. No, I do not. It is not clear that Kroll develops its market risk premium in relation
15 to its normalized risk-free rate. The market risk premium is calculated as the
16 difference between the expected market return and risk-free rate; therefore, it is a
17 function of the expected market return and risk-free rate at a point in time.
18 Consequently, the market risk premium and risk-free rate are not independent of
19 each other, they are interrelated. In fact, academic studies have shown that the two
20 are inversely related.¹⁶¹ As the risk-free rate decreases, the market risk premium
21 increases and vice versa. However, as shown in Figure 7 below, there is no clear
22 relationship between Kroll's recommended Equity Risk Premium and risk-free rate.

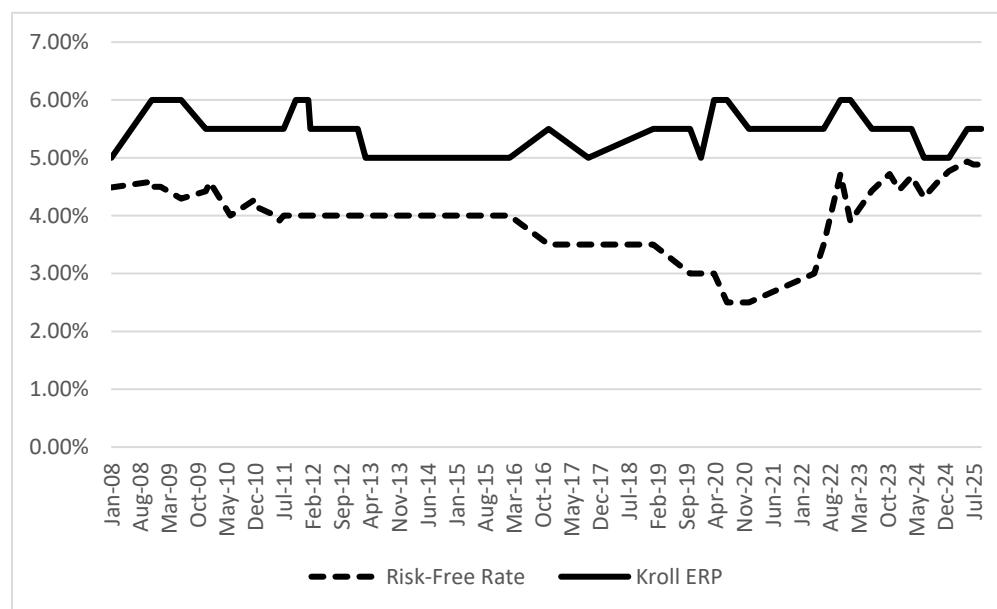
¹⁶⁰ Direct Testimony of Christopher C. Walters, page 63, lines 20-23.

¹⁶¹ See, e.g., Robert S. Harris and Felicia C. Marston, Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts, Financial Management, (Summer 1992), at 63-70.

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1 Whereas academic studies indicate that the two lines should move in opposite
2 directions, Figure 7 shows they do not.

3 **Figure 7 Kroll Recommended Equity Risk Premium and**
4 **Risk-Free Rate (2008-2024)¹⁶²**



5
6 The conclusion that there is no clear relationship between the two variables
7 provided by Kroll is supported by statistical analysis. The R-squared is 0.43
8 percent, which indicates that Kroll's Risk-Free Rate explains less than 1.00 percent
9 of the change in the Equity Risk Premium. This runs counter to the fundamental
10 fact that the market risk premium is a function of the risk-free rate, as noted earlier.
11 Further the two variables are slightly positively correlated, contrary to the fact that
12 the two variables are inversely related and thus should be negatively correlated.

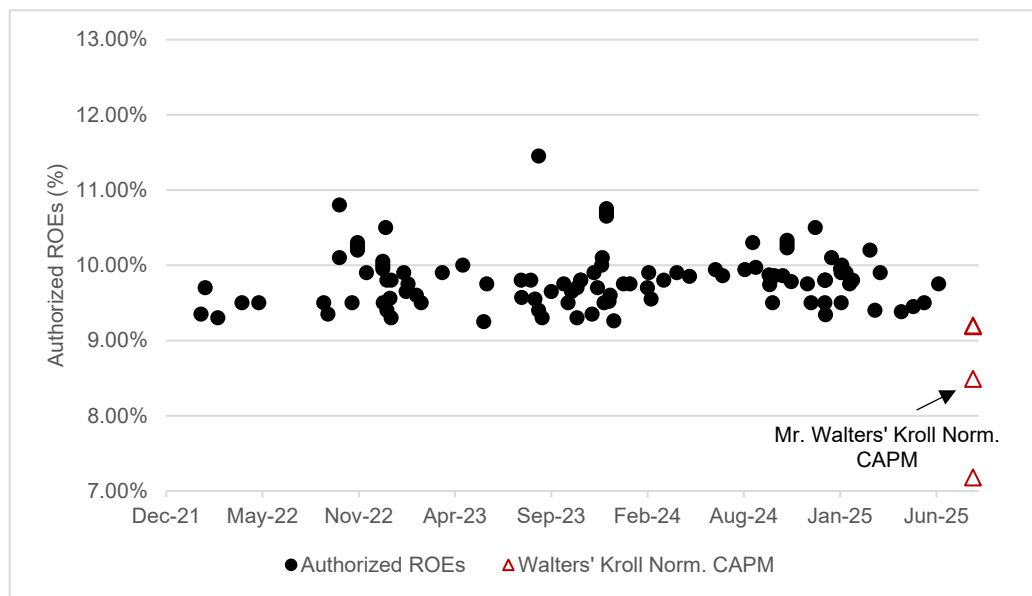
¹⁶² Sources: Kroll Cost of Capital Navigator, Federal Reserve Bank of St. Louis FRED Economic Data.

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1 **Q98. What is the effect of Mr. Walters' Kroll Normalized CAPM results on his**
2 **analysis?**

3 A98. The results of Mr. Walters' CAPM analyses using the Kroll Normalized Method
4 (ranging from 7.18 percent to 9.20 percent) are below any reasonable estimate of
5 DTE Electric's cost of equity. In fact, each are below every ROEs authorized for a
6 vertically integrated electric utility since 2022 (see Figure 8 below). The
7 Commission should give no weight to these estimates.

8 **Figure 8 Mr. Walters' Kroll Normalized Method CAPM vs. Authorized**
9 **ROEs for Vertically Integrated Electric Utilities (2022-2025)¹⁶³**
10



11

12 **Q99. What are your concerns with Mr. Walters' market risk premium estimates**
13 **using the FERC's DCF methodology?**

14 A99. I respectfully disagree with Mr. Walters' approach as it is internally inconsistent
15 and does not reflect the expected market return as a whole.

¹⁶³ Source: RRA. Excludes ROEs authorized for Green Mountain Power that operates under an Alternative Rate Plan in which the ROE is set annually by formula that adjusts the ROE based on changes in the 10-year Treasury bond yield.

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1 The purpose of the analysis is to estimate the return investors expect for the market
2 as a whole, including high- and low-growth companies, not to estimate the
3 aggregate return for companies that pay dividends or those that Mr. Walters
4 believes have proper growth rates. At any point in time, the market as a whole
5 includes companies that are both dividend and non-dividend paying, as well as
6 those with negative and positive growth, even companies with very high or very
7 low growth. Excluding companies because they are non-dividend paying, or
8 because the expected growth rates do not meet arbitrary thresholds, results in an
9 estimate of a subset of the market, not the market as a whole. A good analogy is
10 an investment in a mutual fund or Exchange Traded Fund that tracks the S&P 500
11 Index. Every dollar invested in these funds is invested in all companies in the S&P
12 500 Index; the investor cannot not pick and choose only dividend-paying
13 companies, or only companies with growth rates she deems “sustainable.”

14 Further, excluding companies with growth rates that are believed to be
15 unreasonable creates an internal inconsistency in the CAPM. A fundamental
16 assumption of the CAPM is that the required return is proportional to the risk of the
17 investment. Under the CAPM, the Beta coefficient is the measure of risk and is
18 calculated by comparing the subject security’s returns to the overall market returns.
19 Because the Beta coefficient is calculated relative to the overall market (e.g., the
20 S&P 500 Index or the New York Stock Exchange), it is important that the expected
21 market return also reflects the overall market. Therefore, it is inconsistent to
22 combine Beta coefficients calculated relative to the entire market with a market risk
23 premium estimate calculated using only a subset of the market. Consequently, any

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1 credible estimate of the expected return on the market as a whole must include all
2 companies.

3

4 **Q100. Please explain further why excluding non-dividend paying companies does not**
5 **fully reflect the expected market return.**

6 A100. According to Mr. Walters' workpapers, there are 96 companies in the S&P 500
7 Index that do not currently pay dividends, including some of the largest companies
8 in the Index in terms of market capitalization. Amazon, Boeing, Berkshire
9 Hathaway, Netflix, Palantir Technologies, Tesla, and Uber are among the 96
10 companies that are excluded from the analysis for not paying dividends. Excluding
11 non-dividend paying companies removes approximately \$9.8 trillion
12 (approximately 17.5 percent)¹⁶⁴ from the total market capitalization, skewing the
13 analysis. In my opinion, it is not reasonable to exclude 17.5 percent of the market
14 in calculating an expected market return that is meant to reflect the entire market.

15

16 **Q101. Does Mr. Walters' DCF methodology using "all companies" alleviate your**
17 **concern?**

18 A101. No, it does not. Although Mr. Walters asserts that his second DCF approach
19 includes "all companies," it only adds back the non-dividend paying companies.
20 He still excludes companies with negative growth rates or growth rates greater than
21 20.00 percent, including AT&T, Bristol Meyers Squibb, Broadcom, Citigroup,
22 NVIDIA Corporation, Eli Lilly, Southwest Airlines, and Pfizer. Excluding
23 companies whose growth rates do not meet arbitrary thresholds removes

¹⁶⁴

See, Mr. Walters CCW Public WP 7, tab "SP 500 dcf all cos".

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1 approximately \$14.1 trillion (or approximately 25.2 percent)¹⁶⁵ of the total market
2 capitalization of the S&P 500 Index. Combined, Mr. Walters' approaches exclude
3 approximately 43 percent of the S&P 500 by market capitalization¹⁶⁶ excluding six
4 of the 15 largest companies in the S&P 500 Index by market capitalization. It is
5 simply not accurate to assert that these approaches reflect the expected return on
6 the entire market when it excludes more than 40 percent of the S&P 500 Index's
7 market capitalization.

8

9 **Q102. Mr. Walters suggests your expected market return is "inflated" because**
10 **expected individual growth rates of certain companies exceed his measure of**
11 **GDP growth.¹⁶⁷ What is your response?**

12 A102. I disagree. Determining whether a company's individual growth rate is
13 "sustainable" is highly subjective and introduces bias in the analysis. Mr. Walters'
14 criticism focuses on individual company growth rates he deems as "too high";
15 however, he fails to acknowledge that my expected market return estimates also
16 include growth rates that are unsustainably low. The Value Line expected market
17 return as calculated in Exhibit A-14, Schedule D5.4 includes 46 companies with
18 growth rates equal to or lower than Mr. Walters' 2.40 percent inflation estimate
19 (implying negative real growth). 20 of those have negative growth rates. That is,
20 the analysis includes both high and low growth rates and is not biased toward only
21 high growth rates. In other words, by not attempting to evaluate the sustainability
22 of each of the 500 individual companies' growth rate as Mr. Walters does, I do not

¹⁶⁵ See, Mr. Walters CCW Public WP 7, tab "SP 500 excl. no divs".

¹⁶⁶ I note that there is overlap in some companies that do not pay dividends and those that also have earnings growth rates less than zero or above 20 percent. Tesla, the 9th largest company by market capitalization, is one of those companies.

¹⁶⁷ Direct Testimony of Christopher C. Walters, page 65, lines 10-21.

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1 introduce bias into my expected market return analysis. More importantly, a proper
2 market return estimate must include all companies in the analysis to avoid internal
3 inconsistencies. Mr. Walters' analysis, on the other hand, excludes more than 40
4 percent of the S&P 500 Index, biasing his estimate downward.

5
6 **Q103. What is your response to Mr. Walters' reference to professional investor**
7 **forecasts that indicate expected market returns range from 3.92 percent to**
8 **6.70 percent?**¹⁶⁸

9 A103. I have several concerns with his references. First, Mr. Walters' 9.50 percent ROE
10 estimate is entirely at odds with the data he presents. In this instance, Mr. Walters
11 refers to the market return forecasts summarized in Table 10, below.

12 **Table 10 Summary of Mr. Walters' Market Return Forecast References**¹⁶⁹

Institution	Term (Yrs.)	Market Return Forecast
BlackRock Capital Management	30	6.70%
JP Morgan Asset Management	10 - 15	6.70%
Vanguard	10	2.80% - 4.80%
Research Affiliates	10	3.92%
Invesco	10	5.0% – 6.3%
Goldman Sachs	10	3.00%
Fidelity	20	5.70%
Schwab	10	6.00%

13
14 According to these investment firms, the expected market return ranges from 2.80
15 percent to 6.70 percent for U.S. equities. Mr. Walters, however, estimates an ROE
16 of 9.50 percent for a utility that is less risky than the overall market, as measured

¹⁶⁸ Direct Testimony of Christopher C. Walters, page 55, Table CCW-10 line 1.

¹⁶⁹ Direct Testimony of Christopher C. Walters, page 55, Table CCW-10 at 1..

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1 by the Beta coefficient. Three estimates are below Mr. Walters' projected risk-free
2 rate of 4.60 percent, which means that the market risk premium is negative, which
3 is illogical on its face. These estimates simply have no meaningful value in
4 determining DTE Electric's cost of equity.

5 Intuitively, investment advisors have an inherent incentive to underestimate
6 equity returns because the consequences of overestimating the return outweighs
7 the consequences of underestimating equity returns. Investors are much happier if
8 actual returns exceed predictions, and investment advisors risk losing clients
9 (amongst other negative outcomes) if they overestimate returns.

10

11 **Q104. Please summarize Mr. Walters' concerns with your ECAPM analysis.**

12 A104. Mr. Walters' principal concern with my ECAPM analysis is the use of adjusted
13 Beta coefficients such as those published by *Value Line*.¹⁷⁰ I addressed Mr.
14 Walters' concern in response to Mr. Ufolla and Mr. Coppola earlier and will not
15 repeat my response here.

16

17 **Q105. Please summarize what adjustments you recommend to Mr. Walters' CAPM**
18 **analyses.**

19 A105. First, I recommend that the Commission reject Mr. Walters' CAPM results using
20 Vasicek adjusted Beta coefficients and those using the Kroll Normalized market
21 risk premium. As shown earlier, these results are far below any reasonable estimate
22 of DTE Electric's ROE. Even though I disagree with both of Mr. Walters' FERC
23 DCF market risk premium estimates, if the Commission is going to rely on it, it

¹⁷⁰ Direct Testimony of Christopher C. Walters, page 69, lines 5-21; page 70, lines 1-14, 19; page 71, lines 1-24; and page 72, lines 1-5.

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1 should only give weight to the market risk premium estimate that includes non-
2 dividend paying companies (7.80 percent) even though it still excludes 25 percent
3 of the market.
4 Table 11 below summarizes my recommended adjustments to Mr. Walters'
5 CAPM analyses.

6 **Table 11 Adjustments to Mr. Walters' CAPM**

	Kroll Normalized MRP (5.50%)	Risk Premium Derived MRP (7.00%)	FERC DCF MRP (including non-div companies, 7.80%)
Current VL Beta	Reject	10.06%	10.69%
Historical VL Beta	Reject	10.08%	10.70%
S&P Vasicek Beta	Reject	Reject	Reject
3-year S&P Blume Adj. Beta	Reject	9.17%	9.69%
Average			10.07%

7

8 **Q106. What is your conclusion with regard to Mr. Walters' analyses and ROE**
9 **recommendation?**

10 A106. Mr. Walters' analyses include several flaws that produce results that fail to meet
11 the *Hope* and *Bluefield* standards for a fair return. Table 12 demonstrates that
12 eliminating Mr. Walters' analyses based on flawed assumptions, or making small,
13 reasonable adjustments, produces ROE results ranging from 10.07 percent to 10.61
14 percent. The midpoint of this range of 10.34 percent.

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1

Table 12 Recommended Adjustments to Mr. Walters' ROE Results

ROE Methodology	Mr. Walters' Range	Range of Revised Model Results	Average of Revised Model Results
DCF – include only Constant Growth “Analysts’ Growth” Method	8.36% - 10.65%	10.57% - 10.65%	10.61%
Risk Premium – Fully reflect inverse relationship	9.87% - 10.06%	10.48% - 10.53%	10.52%
CAPM – reject Kroll MRP and Vasicek Betas	7.18% - 10.54%	9.17% - 10.70%	10.07%
Range of Averages		10.07% - 10.61%	
Midpoint		10.34%	

2

3 As a basic test of logic, Mr. Walters' analysis and ROE recommendation are
4 incompatible with the current capital market for a vertically integrated electric
5 utility such as DTE Electric. Mr. Walters' recommendation to reduce DTE
6 Electric's authorized ROE by 40 basis points when long-term government and
7 utility bond yields remain similar to, or have slightly increased, since DTE
8 Electric's last ROE authorization of 9.90 percent fails to allow the Company to
9 sufficiently recover its capital costs.

10 Financial Integrity

11 **Q107. Mr. Walters assesses the Staff's ROE and capital structure recommendations**
12 **on DTE Electric's financial integrity based on a review of S&P's and Moody's**
13 **credit metric analysis. Do you have any concerns with Mr. Walters' analysis?**

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1 A107. Yes, I do. Mr. Walters' financial integrity analysis is an oversimplified view that
2 fails to take into consideration the many quantitative and qualitative factors
3 considered by the credit rating agencies. Although credit rating agencies review
4 cash flow and leverage metrics in their credit determinations, the actual assessment
5 of those metrics is far more complex than Mr. Walters' analysis suggests. Cash
6 Flow/Leverage considerations are one element of a broad set of criteria.¹⁷¹ Unlike
7 Mr. Walters' analysis, the rating agencies' assessment does not look to a single
8 period or assume static relationships among variables. S&P for example reviews
9 credit ratios "on a time series basis with a clear forward-looking bias."¹⁷² Further,
10 the ratios depend on "base case" projections considering "current and near-term
11 economic conditions, industry assumptions, and financial policies."¹⁷³
12 Consequently, relying on pro forma credit metrics to assess the credit implications
13 of any specific ROE and equity ratio is a partial analysis that may lead to incorrect
14 conclusions.
15 Moreover, the quality of the regulatory environment is among the most important
16 factors that rating agencies consider in evaluating the creditworthiness of utilities.
17 Recommendations to reduce DTE Electric's authorized ROE when capital costs
18 have risen, combined with a more leveraged capital structure, would introduce a
19 level of unpredictability in Michigan's regulatory environment. Changes in the
20 perception of the regulatory environment can have significant consequences on the
21 rating agencies' credit metric thresholds.

¹⁷¹ Standard & Poor's Ratings Services, *Corporate Methodology*, at 3 (January 7, 2024).

¹⁷² Standard & Poor's Ratings Services, *Corporate Methodology*, at 31 (January 7, 2024).

¹⁷³ Standard & Poor's Ratings Services, *Corporate Methodology*, at 32 (January 7, 2024).

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1 Reducing the Company's authorized ROE reduces cash flow, while more debt in
2 the capital structure increases the denominator of the cash flow-to-debt ratio. The
3 result is that both actions would hinder the Company's ability to maintain credit
4 metrics above its downgrade thresholds.

5

6 **Response to CUB Witness Bandyk**

7 **Q108. Please summarize Mr. Bandyk's ROE recommendation in this case.**

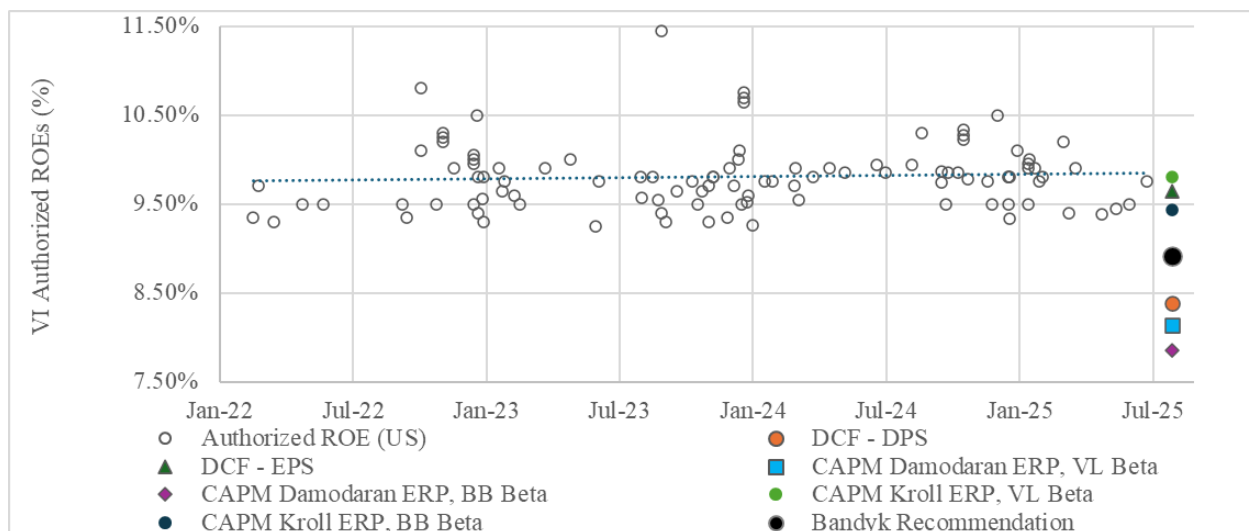
8 A108. Mr. Bandyk recommends the Commission authorize an ROE of 8.91 percent.¹⁷⁴ As
9 an alternative, Mr. Bandyk recommends the Commission authorize an ROE of 9.4
10 percent, which is the midpoint of Mr. Bandyk's recommendation (8.91 percent) and
11 DTE Electric's current authorized ROE (9.90 percent). Mr. Bandyk's 8.91 percent
12 recommendation is the average of his 9.01 percent DCF estimate and his 8.80
13 percent CAPM estimate.¹⁷⁵ Mr. Bandyk's analyses apply many of the same flawed
14 inputs and methodologies as discussed in response to Messrs. Ufolla, Coppola, and
15 Walters, and I will not repeat those arguments. As shown in Figure 9 below, the
16 results of Mr. Bandyk's various methodologies are unreasonably low and should
17 be dismissed as outliers.

¹⁷⁴ Direct Testimony of Matthew J. Bandyk, page 5, lines 3-4.

¹⁷⁵ Direct Testimony of Matthew J. Bandyk, page 15, line 2.

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**Figure 9 Mr. Bandyk's ROE Results vs. Authorized ROEs for
Vertically Integrated Electric Utilities¹⁷⁶**



Q109. Do Mr. Bandyk's ROE recommendations meet the *Hope* and *Bluefield* standards for a fair rate of return?

A109. No. Mr. Bandyk's primary recommendation of 8.91 percent is far below any reasonable measure of DTE Electric's cost of equity. As shown in Figure 9 above, Mr. Bandyk's unreasonably low recommendation is driven by his reliance on results that are clear outliers and do not meet the *Hope* and *Bluefield* standards for a fair return.

There have only been only two cases in the last 45 years in which an ROE of 8.91 percent or lower has been authorized for a vertically integrated electric utility.¹⁷⁷

Those cases were in 2019 and 2021, when the interest rate and inflation environment was substantially lower than it is now. As noted earlier, Arizona

¹⁷⁶ Source: RRA. Rate case decisions for vertically integrated electric utilities as of July 31, 2025. Excludes decisions with companies that operate under a formula rate plan or decisions with ROE penalties.

¹⁷⁷ Source: Regulatory Research Associates. Excludes decisions for Green Mountain Power that operates under an Alternative Rate Plan where the ROE is set annually by formula based on changes in the 10-year Treasury yield.

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1 Public Service Company (“APS”) was downgraded immediately following a
2 November 2021 order that included an 8.70 percent ROE¹⁷⁸ inclusive of a 20-basis
3 point penalty. RRA commented that the decision was “negative from an investor
4 perspective” that imposed “numerous disallowances on the utility, and has garnered
5 strong reactions in the investment community.”¹⁷⁹ Despite a more favorable
6 decision in March 2024 that increased the authorized ROE to 9.55 percent, APS’s
7 credit rating has remained the same. An ROE in the range of Mr. Bandyk’s
8 recommendation is likely to be viewed very unfavorably by the financial
9 community; moreover, it would introduce a heightened level of instability and
10 unpredictability in Michigan’s regulatory environment which would increase the
11 regulatory risk and cost of capital for all Michigan utilities.

12

13 **Q110. Mr. Bandyk references several articles that suggest that authorized ROEs**
14 **exceed market returns.¹⁸⁰ Do you agree with the conclusions of the authors of**
15 **those articles?**

16 A110. No, I do not. The referenced articles contain serious flaws in the logic that would
17 not withstand the scrutiny of a regulatory commission proceeding. For example,
18 Mr. Bandyk references a 2021 paper by Karl Dunkle Werner and Stephen Jarvis
19 entitled “Rate of Return Regulation Revisited” and a 2019 study in the journal
20 Energy Policy by David Rode and Paul Fischbeck that assert that authorized ROEs
21 were above levels that historical relationships would suggest. The first flaw is that

¹⁷⁸ I note that the case was appealed and the authorized ROE was increased to 8.90 percent on remand.

¹⁷⁹ Regulatory Research Associates, “Arizona Public Service electric rate case decision viewed as negative for investors,” December 3, 2021.

¹⁸⁰ Direct Testimony of Matthew J. Bandyk, page 7, lines 17-19; page 8, lines 9-16; page 9, lines 1-10; and page 10, lines 1-3.

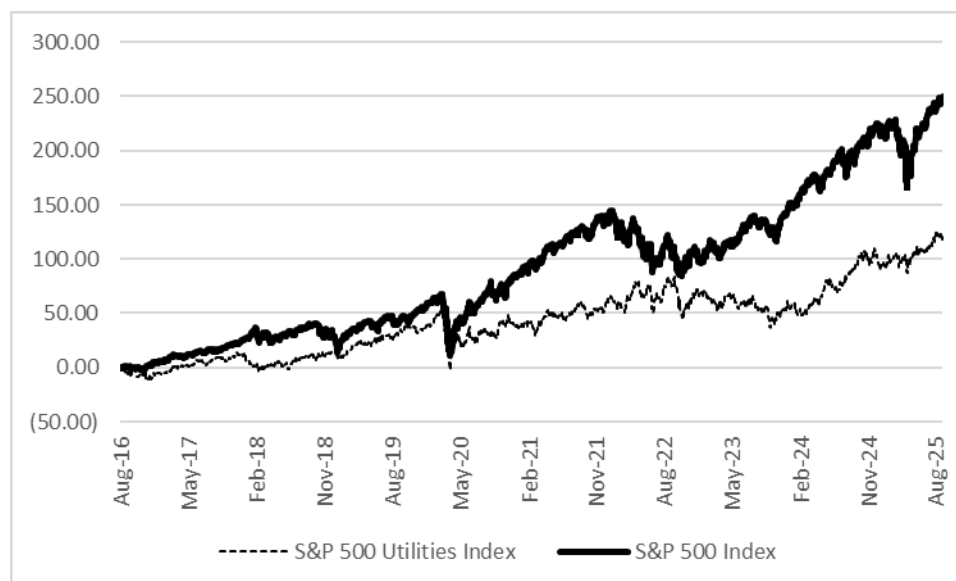
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1 authors of these studies only rely on the CAPM to estimate the cost of equity,
2 whereas investors and most regulatory commissions consider multiple models
3 when determining the appropriate cost of equity. Additionally, the CAPM as
4 specified by Dunkle Werner and Jarvis has certain limitations for measuring the
5 cost of equity and relies on assumptions that are inconsistent with current market
6 data. The authors assume a constant market risk premium and a constant unlevered
7 Beta coefficient. Therefore, both measures of equity risk are held constant and thus
8 do not incorporate changes in market risk premia or changes in industry risk that
9 have occurred over the study period. A more complete CAPM, as well as outputs
10 from alternative models, such as the DCF and Bond Yield Plus Risk Premium
11 models, demonstrate that regulators' authorized ROEs are consistent with evidence
12 of investors' return requirements and are not overcompensating utilities. This
13 highlights the importance of considering the evidence produced by multiple
14 methodologies provided in the context of capital market conditions at the time.
15 Rode and Fischbeck acknowledge the decline in the risk-free rate over time, but do
16 not even test that variable in any of their econometric tests. As shown in my Bond
17 Yield Plus Risk Premium analyses, and as further demonstrated as in my response
18 to Mr. Walters, changes in the equity risk premium are strongly related to changes
19 in the risk-free rate. Rode and Fischbeck simply ignore one of the most important
20 variables that explains changes in the equity risk premium.
21 Mr. Bandyk also cites an August 2016 article by Steve Huntoon in Public Utilities
22 Fortnightly that discusses utility stock outperformance over a recent period and
23 suggests that utilities should not outperform the broad market because they are less
24 risky than competitive industries. However, because utilities are defensive stocks,
25 they often (but do not always) outperform the market during economic downturns

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1 as investors allocate capital to less risky sectors. Much of the historical period that
2 Mr. Huntoon reviews occurred during the Great Recession and slow economic
3 recovery thereafter. Therefore, it is not surprising that the utility sector may have
4 outperformed the market during this period. I note that since August 2016, the S&P
5 500 Utilities Index underperformed the S&P 500 Index as shown in Figure 10
6 below.

7 **Figure 10 Total Return in the S&P 500 Index vs. S&P 500 Utilities**
8 **Index (August 2016-August 2025)**



9
10 Additionally, Mr. Huntoon cites Burton Malkiel's "A Random Walk Down Wall
11 Street," a book that is over 50 years old, that references an expected market return
12 of seven percent. As shown in Table 13 below, since Mr. Huntoon's article in 2016,
13 the total return on the S&P 500 has been 15.8 percent, on average.

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Table 13 Annual Total Return on Large Company Stocks¹⁸¹

Year	Total Return
2016	11.96%
2017	21.83%
2018	-4.38%
2019	31.49%
2020	18.40%
2021	28.71%
2022	-18.11%
2023	26.61%
2024	25.62%
2016-2024 Average	15.79%

2

3

Given that over the last nearly 100 years the market has returned more than 12 percent on average over multiple business cycles – including the Great Depression, post-World War II expansion, stagflation of the 1970s and 1980s, and the dot com boom and age of the Internet – it is difficult to reconcile what structural changes in the economy could occur that would cut returns by 40 percent over the long term.

8

In summary, Mr. Bandyk’s erroneous conclusion that authorized ROEs have exceeded market returns is due to faulty and illogical measures of the market return, not because commissions like this Commission have been setting authorized ROEs above the market cost of equity. As compared to the market returns shown in Table 13 above, authorized ROEs have been far below returns on the market.

9

10

11

12

¹⁸¹ Source: Kroll, 2023 SBBI Yearbook, Appendix A-1 (years 1926-2022); Cost of Capital Navigator (2023-2024 data).

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1 **Q111. Mr. Bandyk disagrees that an authorized ROE below returns authorized for**
2 **other utilities impedes a utility's ability to attract capital.¹⁸² What is your**
3 **response?**

4 A111. Mr. Bandyk is mistaken. The authorized ROE is a measure of the opportunity cost
5 of capital. If given the choice between an investment in a utility with a higher
6 authorized return vs. one with a lower return, investors will choose the former all
7 else equal. Further, the authorized ROE and capital structure are primary drivers of
8 cash flow and earnings. An unduly low authorized ROE and equity ratio puts
9 pressure on credit metrics that can have adverse effects on a Company's credit
10 profile and credit rating that both debt and equity investors consider when
11 evaluating their investment options and determining their return requirements. A
12 utility with a weaker credit profile will be less attractive to investors, which
13 hampers its ability access capital on favorable terms relative to utilities with
14 stronger credit profiles.

15 DCF Analysis

16 **Q112. Please summarize Mr. Bandyk's DCF analyses.**

17 A112. Mr. Bandyk performs two Two-Stage DCF analyses using the FERC's
18 methodology applied to the same proxy group as I use. The first DCF analysis
19 applies analyst earnings growth rate projections as the initial stage and a long-term
20 growth rate based on a nominal GDP growth rate projected for 2028-2035 (proxy
21 group average ROE of 9.65 percent). His second DCF analysis applies the same
22 approach, but uses projected dividend growth rates from Value Line (proxy group
23 average ROE estimate of 8.38 percent). For the reasons explained earlier, GDP
24 growth is an unfounded constraint. The utility sector has grown faster than GDP

¹⁸²

Direct Testimony of Matthew J. Bandyk, page 12, lines 10-21.

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1 over many decades and it is inconsistent with financial theory and the DCF model's
2 assumptions to assume that all companies will grow at the same rate in perpetuity.
3 Moreover, despite his criticism that the projected earnings and dividend growth
4 rates are short-term,¹⁸³ Mr. Bandyk uses a relatively short-term forecast of GDP
5 growth for the perpetual growth rate.

6

7 **Q113. Mr. Bandyk disagrees with the use of 90- or 180-trading day averaging**
8 **periods.¹⁸⁴ What is your response?**

9 A113. As can be seen by the various approaches taken by the Opposing Witnesses, there
10 are a variety of approaches used to calculate recent average for relevant market
11 data. Mr. Ufolla asserts that the 30-day average is too short, while Mr. Bandyk
12 asserts the 90- and 180-day averages run the risk of relying on stale data. Mr.
13 Coppola uses a 30-day average, while Mr. Walters uses a 13-week average (roughly
14 three months). Mr. Walters also reviews three and six month bond yields in his
15 Risk Premium analysis. The fact that each of the witnesses take various approaches
16 to calculating recent averages in their market data support the reasonableness of
17 considering of multiple averaging periods and demonstrates my approach is
18 consistent with the methodologies applied by practitioners.

19

20 **Q114. Are dividend growth rates appropriate measures of growth in the DCF model?**

21 A114. No, they are not. Over the long term, dividend growth can only be sustained by
22 earnings growth. Additionally, dividend growth depends on management decisions
23 regarding the dividend payout ratio over the near term and may not necessarily
24 reflect the long-term growth prospects of the company. Further, Value Line is the

¹⁸³ Direct Testimony of Matthew J. Bandyk, page 25, lines 2-9.

¹⁸⁴ Direct Testimony of Matthew J. Bandyk, page 27, lines 11-16.

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1 only source I am aware of that publishes dividend growth rate projections. As such,
2 they are more susceptible to potential bias than earnings growth rates which are
3 reported by many sources and generally represent a consensus view. The fact that
4 dividend growth rate projections are not widely reported by other sources further
5 supports the conclusion that earnings growth is the most meaningful measure of
6 growth among the investment community. In other words, if investors relied
7 heavily on projections of dividend or book value growth, more sources would offer
8 that data. As noted earlier, when providing guidance to investors regarding the
9 overall total return targets in their investor presentations, companies define the total
10 return as the dividend yield plus *earnings* growth, not dividend growth.

11

12 **Q115. Do academic studies support the use of dividend growth rates in investors'**
13 **stock valuations?**

14 A115. No. Academic studies suggest that investors base their investment decisions on
15 analysts' expectations of growth in earnings.¹⁸⁵ Additionally, analysts' consensus
16 earnings forecasts are better at predicting the valuation of common stocks.¹⁸⁶
17 Additionally, a 2002 study in the *Journal of Accounting Research* examined "the
18 valuation performance of a comprehensive list of value drivers" and found that
19 "forward earnings explain stock prices remarkably well" and were generally
20 superior to other value drivers analyzed.¹⁸⁷ A 2012 study from the journal
21 *Contemporary Accounting Research* found that the sell-side analysts with the most

¹⁸⁵ See, e.g., Harris and Marston, *Estimating Shareholder Risk Premia Using Analysts Growth Forecasts*, *Financial Management*, Summer 1992, at 65; and Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, *The Journal of Portfolio Management*, Spring 1988, at 81. Please note that while the original study was published in 1988, it was updated in 2004 under the direction of Dr. Vander Weide. The results of that updated study are consistent with Vander Weide and Carleton's original conclusions.

¹⁸⁶ Direct Testimony of Jennifer E. Nelson, page 24, lines 18-25 and page 25, lines 1-11.

¹⁸⁷ Liu, Jing, et al., "Equity Valuation Using Multiples," *Journal of Accounting Research*, Vol. 40 No. 1, March 2002.

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1 accurate stock price targets were those whom the researchers found to have more
2 accurate earnings forecasts.¹⁸⁸ I am not aware of any similar findings regarding
3 dividend growth or GDP growth estimates. I note that no other witness in this
4 proceeding uses dividend growth rates.

5

6 **Q116. What would Mr. Bandyk's DCF analysis be if it was revised to only rely on**
7 **projected earnings growth rates?**

8 A116. As shown in Exhibit A-39 Schedule DD2.15, revising Mr. Bandyk's DCF analysis
9 to rely only on projected earnings growth rates produces an ROE estimate of 10.19
10 percent for his proxy group on average. I note that Mr. Bandyk relies on my annual
11 dividends and earnings growth rates as of January 31, 2025, combined with his
12 stock prices as of July 18, 2025, creating an internal inconsistency in his analysis.

13 CAPM Analysis

14 **Q117. Please summarize Mr. Bandyk's CAPM analyses and results.**

15 A117. Mr. Bandyk applies two estimates of the risk-free rate, two estimates of the Beta
16 coefficient, and two estimates of the market risk premium to develop four CAPM
17 estimates that range from 7.85 percent to 9.80 percent.¹⁸⁹

18

19 **Q118. Do you have any concerns with Mr. Bandyk's risk-free rates?**

20 A118. Yes, I do. Mr. Bandyk's 4.24 percent risk-free rate is the yield on the 10-year
21 Treasury bond.¹⁹⁰ In determining the security most relevant to the application of

¹⁸⁸ Gleason, C.A., et al., "Valuation Model Use and the Price Target Performance of Sell Side Equity Analysts," *Contemporary Accounting Research*.

¹⁸⁹ Direct Testimony of Matthew J. Bandyk, page 15, line 2 and Exhibit CUB-5.

¹⁹⁰ Mr. Bandyk relies on NYU Professor Dr. Aswath Damodaran's risk-free rate and implied equity risk premium model. Dr. Damodaran uses the 10-year Treasury bond as the risk-free rate in his implied equity risk premium model. This is noted in Mr. Bandyk's Figure 3 on page 18 of his direct testimony.

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1 the CAPM, it is important to select the term that best matches the life of the
2 underlying investment. As explained by Morningstar:

3 *The traditional thinking regarding the time horizon of the chosen*
4 *Treasury security is that it should match the time horizon of whatever is*
5 *being valued... Note that the horizon is a function of the investment,*
6 *not the investor. If an investor plans to hold stock in a company for*
7 *only five years, the yield on a five-year Treasury note would not be*
8 *appropriate since the company will continue to exist beyond those five*
9 *years.*¹⁹¹

10 Since utility assets are long-duration investments, it is appropriate to use yields on
11 long-term Treasury bonds as the risk-free rate component of the CAPM. Therefore,
12 the 30-year Treasury bond is the most appropriate security for that purpose.

13

14 **Q119. What Beta coefficients does Mr. Bandyk apply?**

15 A119. Mr. Bandyk uses adjusted Beta coefficients reported by Value Line and Bloomberg
16 and converts them to raw Beta coefficients by removing the Blume adjustment.¹⁹²
17

18 **Q120. Please respond to Mr. Bandyk's claim that there is "extensive academic**
19 **literature supporting the inapplicability of the Blume adjustment when it**
20 **comes to utilities."**¹⁹³

21 A120. Despite referencing "extensive academic literature," Mr. Bandyk cites to two
22 studies, one of which is primarily focused on Australian natural gas utilities using
23 study periods that are approximately 20 or more years old.¹⁹⁴ For the analysis
24 relating to U.S. natural gas distribution utilities, the authors' studies showed a
25 significant increase in Beta post the "Technology Bubble" (i.e., 2002-2007) with
26 the high end of the 95 percent confidence interval increasing to 1.0 for the average

¹⁹¹ Morningstar Inc., Ibbotson SBBI 2013 Valuation Yearbook, at 44.

¹⁹² Direct Testimony of Matthew J. Bandyk, page 22, lines 12-15.

¹⁹³ Direct Testimony of Matthew J. Bandyk, page 23, lines 9-10.

¹⁹⁴ Direct Testimony of Matthew J. Bandyk, page 23, lines 12-17.

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1 portfolio return.¹⁹⁵ As seen during the COVID-19 era, it is possible for utility Beta
2 coefficients to reach near 1.0.

3

4 **Q121. Are raw Beta coefficients widely used by rate of return analysts in regulatory**
5 **proceedings or been accepted by regulatory commissions?**

6 A121. No. I am not aware of any regulatory commission that has accepted the use of raw
7 Beta coefficients. Value Line and Bloomberg are widely used by investors and
8 both use the Blume adjustment. Mr. Bandyk's raw Beta coefficients should be
9 rejected.

10

11 **Q122. Do you agree with Mr. Bandyk's use of the market risk premium estimates**
12 **from Kroll and NYU?**

13 A122. No, I do not. I explain in detail the flaws with Kroll's methodology in response to
14 Mr. Walters and will not repeat those arguments here.

15 Turning to the NYU Implied Equity Risk Premium model, as Mr. Bandyk explains,
16 the approach applies a multi-stage DCF analysis for the S&P 500 Index in which
17 the first stage of growth relies on an estimate of analysts' earnings growth rates for
18 the first five years, and a terminal stage of growth equal to the 10-year Treasury
19 bond yield for years six through perpetuity. The Implied Equity Risk Premium
20 model assumes the 10-year Treasury bond yield as the risk-free rate, which is also
21 equal to the discount rate. The assumed terminal growth rate is an especially critical
22 input because the large majority of the cash flows that are discounted depend
23 substantially on it.

¹⁹⁵ Allen Consulting Group, "Empirical evidence on proxy beta values for regulated gas distribution activities," June 2007, at 19-20. <https://www.aemc.gov.au/sites/default/files/content/3016ea51-04c4-4b64-890c-845d23d2c47d/Annexure-C-Empirical-Evidence-on-Proxy-Betas.pdf>

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1 In my opinion, the Implied Equity Risk Premium model's assumptions are
2 not reasonable or consistent with the cost of equity analyses that I see typically
3 applied in utility regulatory proceedings. For example, the other witnesses in this
4 proceeding have assumed a risk-free rate using the 30-year Treasury bond yield,
5 not the 10-year Treasury bond yield. Additionally, the assumption that the market
6 will grow in the long term at the rate of a risk-free government bond backed by the
7 full faith and credit of the U.S. government defies financial theory. Investors require
8 a premium to compensate them for the risk of investing in equities relative to
9 government bonds. Investors simply would not be satisfied with growth equal to
10 the rate of return they could earn on a risk-free security. These concerns should not
11 be construed to mean I am criticizing the Implied Equity Risk Premium model for
12 academic purposes; rather it is my opinion that the Implied Equity Risk Premium
13 model has limited application for utility ratemaking purposes given its underlying
14 assumptions. For these reasons, it should be rejected.

15

16 **Q123. Mr. Bandyk criticizes historical-based estimates of the market risk**
17 **premium.¹⁹⁶ What is your response?**

18 A123. Mr. Bandyk's first concern is that historical-based estimates are sensitive to the
19 historical time period selected and is exposed to subjective bias. I rely on the entire
20 99-year historical data period available, so I have not introduced subjective bias
21 with respect to the appropriate historical time period.

22 Mr. Bandyk's second concern is that historical estimates of the market risk
23 premium are subject to survivorship bias. I note that Mr. Bandyk relies on the NYU
24 Implied Equity Risk Premium model to estimate the expected return on the S&P

¹⁹⁶

Direct Testimony of Matthew J. Bandyk, page 16, lines 9-18 and page 17, lines 1-6.

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1 500 Index, which is routinely updated to remove companies that do not survive or
2 are no longer traded on a major U.S. stock exchange. To the extent that
3 survivorship bias is a concern, the NYU Implied Equity Risk Premium analysis is
4 similarly exposed to such concerns.

5 Bond Yield Plus Risk Premium Analysis

6 **Q124. What is your response to Mr. Bandyk's criticisms of your Bond Yield Plus**
7 **Risk Premium analysis?**

8 A124. Mr. Bandyk asserts that the approach is not based on objective data, that it
9 perpetuates excessive ROEs, and that the FERC has rejected the approach.¹⁹⁷ I
10 disagree on all three points.

11 First, every regulatory commission in the country that I am aware of adheres to the
12 *Hope* and *Bluefield* standards with regard to determining the authorized return and
13 considers a broad range of market-based data applied to various financial models.
14 To suggest that regulators – including this Commission – do not base their
15 authorized ROE determinations on a robust review of objective market data is
16 inaccurate and without merit. Even if it were the case that Mr. Bandyk's financial
17 models were accurate and "objective" estimates of the Company's cost of equity
18 (which they are not), an authorized ROE in the ranges produced by most of Mr.
19 Bandyk's methodologies would (1) fail to provide a return commensurate with
20 returns available to other investments of similar risk, and (2) deny DTE Electric a
21 return sufficient to attract capital and ensure confidence in its financial integrity to
22 maintain its credit. The U.S. Supreme Court has held that under the statutory
23 standard of "just and reasonable," it is the reasonableness of the end result, not the

¹⁹⁷ Direct Testimony of Matthew J. Bandyk, page 28, lines 18-21 and page 29, lines 1-7.

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1 methodologies applied, that is controlling.¹⁹⁸ In that respect, Mr. Bandyk's ROE
2 recommendation, and the analytical results on which it is based, fail that standard.
3 Second, for the reasons explained earlier, Mr. Bandyk relies upon flawed and
4 outdated studies in reaching his conclusion that authorized ROEs exceed market
5 returns.

6 With respect to the FERC's stance on the Risk Premium model, Mr. Bandyk has
7 not cited FERC's most recent decision regarding the Risk Premium analysis. In its
8 most recent Order on the ROE topic, FERC explained that, "[t]herefore, while we
9 do not adopt the Risk Premium model here for the reasons discussed above, we do
10 not foreclose the use of a Risk Premium model in future proceedings if parties can
11 demonstrate the concerns discussed above have been addressed."¹⁹⁹ As such, FERC
12 has not "ruled out" the Risk Premium model; it would consider it if parties can
13 demonstrate that its concerns have been addressed. Thus, the FERC has not closed
14 the door entirely on the Risk Premium analysis.

15 Business Risk Factors

16 **Q125. Mr. Bandyk disagrees that the Company's business risk factors support an**
17 **adjustment to the authorized ROE.²⁰⁰ As a preliminary matter, does your**
18 **ROE recommendation include an explicit adjustment to reflect DTE Electric's**
19 **business risk factors?**

20 A125. No it does not. As explained in my direct testimony, my recommendation reflects
21 the midpoint of my recommended ROE range and I have not made an explicit
22 adjustment on account of DTE Electric's business risks.

¹⁹⁸ *Hope*, 320 U.S. at 602.

¹⁹⁹ *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 189 FERC ¶ 61,036 (October 2024).

²⁰⁰ Direct Testimony of Matthew J. Bandyk, page 29, lines 12-15.

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1 **Q126. Do you agree with Mr. Bandyk's position that the level of DTE Electric's**
2 **capital expenditures is not relevant to its business risk profile, rather it is the**
3 **risk of cost recovery in a timely fashion that is of sole concern?**²⁰¹

4 A126. I agree that the risk of full and timely cost recovery explains part of the risk
5 associated with elevated levels of capital expenditures. However, Mr. Bandyk
6 ignores other risks pertaining to high levels of capital expenditures. First, a full and
7 timely return must include full recovery of the Company's capital costs. As
8 demonstrated above, Mr. Bandyk's recommended ROE and capital structure would
9 not adequately recover DTE Electric's capital costs. Second, the authorized return
10 must be sufficient to provide the cash flow necessary to fund higher levels of capital
11 expenditures, as well as support the Company's credit and enable it to compete for
12 external capital on favorable terms. My analysis regarding the ratio of capital
13 expenditures to net plant relative to the proxy group indicates that the Company
14 relies more heavily on external capital to fund its investment than the proxy group
15 companies.²⁰² Capital is finite and the Company and its peers compete for capital
16 from the same pool of investors. To compete for the significant amount of external
17 capital from debt and equity investors that its heightened level of capital
18 expenditures will require, DTE Electric must provide a competitive return relative
19 to those available from other vertically integrated electric utilities like DTE
20 Electric. An ROE in the range of Mr. Bandyk's recommendations would inhibit
21 the Company's ability to compete for capital and constrain its ability to execute on
22 its investment plans.

²⁰¹ Direct Testimony of Matthew J. Bandyk, page 30, lines 3-9.

²⁰² Direct Testimony of Jennifer E. Nelson, pages 43, lines 15-21 and page 44, lines 1-2 (Figure 6).

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1 **Q127. Does a utility's credit rating fully capture the risks to equity investors as Mr.**
2 **Bandyk suggests?**²⁰³

3 A127. No. Credit ratings, while important, are not the only consideration in assessing
4 business or financial risk, and the risks for equity investors are not the same as the
5 risks for bondholders. Credit ratings assess the likelihood a company could default
6 on its debt. Equity investors are more concerned with cash flow and earnings,
7 including regulatory support for recovery of prudently-incurred costs, capital
8 spending, changes in interest rates, changes in long-term weather patterns, and
9 exposure and opportunities related to decarbonization of the industry. Bondholders
10 are focused on whether a company can meet its debt and other financial obligations
11 as they come due.

12

13 **Q128. How do the Company's capital expenditure needs compare to some of its**
14 **peers' recent announcements?**

15 A128. As shown in Figure 7 of my direct testimony, the Company's planned capital
16 investments as a ratio of its net plant is the highest among the proxy group.
17 Additionally, several companies have recently announced increased capital
18 investment plans in the tens of billions of dollars, including AEP (up from \$54
19 billion to \$70 billion)²⁰⁴ and Duke Energy (increased to \$87 billion).²⁰⁵ Thus it is
20 vitally important that the Commission authorize an ROE and capital structure that
21 will enable DTE Electric to compete for capital among its peers on cost effective
22 and favorable terms for customers.

²⁰³ Direct Testimony of Matthew J. Bandyk, page 30, lines 10-17 and page 31, lines 7-11.

²⁰⁴ <https://www.aep.com/news/stories/view/10354/>

²⁰⁵ <https://www.reuters.com/business/energy/duke-energy-boosts-capex-87-billion-sells-florida-unit-stake-provide-funds-2025-08-05/>

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1 **Q129. Are the risks associated with Company's capital expenditure requirements**
2 **associated with its clean energy mandates and its expenditures associated with**
3 **other types of capital one and the same as Mr. Bandyk asserts?**²⁰⁶

4 A129. Not entirely. The credit pressure associated with elevated levels of capital
5 expenditures is agnostic to whether those expenditures are associated with clean
6 energy or any other type of capital. However, there is policy risk associated with
7 clean energy investments which potentially could cause stranded costs. As noted
8 earlier, the current economic policy climate is highly uncertain, and to the extent
9 that state or federal policy may change after the Company has expended funds to
10 meet clean energy mandates, shareholders bear the risk of policy changes.

11 **Response to Walmart Witness Lyon**

12 **Q130. Please summarize the ROE testimony of Walmart Witness Lyon.**

13 A130. Walmart Witness Lyon does not provide a specific ROE recommendation in this
14 proceeding. Instead, Witness Lyon asserts that the Company's proposed ROE is
15 unreasonable in light of (1) the customer impact of the resulting revenue
16 requirement increase, (2) the reduced risk associated with Michigan's regulatory
17 framework and Commission precedent, and (3) ROEs recently approved in
18 Michigan and by other utility regulatory commissions nationwide.²⁰⁷
19 By way of evidence, Walmart Witness Lyon provides data from RRA regarding
20 authorized return for electric investor-owned utilities from January 2023 through
21 July 24, 2025. Walmart Witness Lyon states that the average ROE for vertically
22 integrated utilities authorized during this period is 9.77 percent. He further states

²⁰⁶ Direct Testimony of Matthew J. Bandyk, page 31, lines 14-17 and page 32, lines 1-3.

²⁰⁷ Direct Testimony of Matthew T. Lyon, page 10, lines 5-13.

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1 that the Company's proposed ROE would be tied for the second highest approved
2 ROE for a vertically integrated utility during this analysis period.²⁰⁸

3

4 **Q131. What is your response to Walmart Witness Lyon on those points?**

5 A131. First, authorized ROEs are, by nature, backward looking. While they can be a
6 broad benchmark to assess the reasonableness of an ROE recommendation, one
7 must recognize that authorized ROEs are determined based on model input data
8 and capital market data that are often lagged by the time a regulatory commission
9 issues its final order. By referencing the average of all decisions between 2023 and
10 2025, Walmart Witness Lyon gives equal weight to authorized ROEs based on data
11 that may be years old as well as to more current authorized ROEs. Further Mr.
12 Lyon did not include correct data for some of his observations, which I correct in
13 Table 14 below.

14 **Table 14 Average Authorized ROEs for Vertically Integrated Electric Utilities**
15 **(2023-2025)²⁰⁹**

Year	WAL-2 As Filed	Corrected	≥ 9.90%
2023	9.71%	9.80%	28%
2024	9.85%	9.84%	34%
2025	9.74%	9.74%	43%
2023-2025	9.77%	9.81%	33%

16

17 I note that there have only been 14 decisions thus far in 2025, thus 2025 is a
18 relatively small sample size at this point in the year. Nonetheless, approximately

²⁰⁸ Direct Testimony of Matthew T. Lyon, page 15, lines 1-6 and page 16.

²⁰⁹ Source: Regulatory Research Associates. I note that Walmart Witness Lyon's Exhibit WAL-3 inexplicably excludes four vertically integrated utility rate case outcomes ranging from 9.70% to 10.75% and reports incorrect authorized ROEs for Appalachian Power Company in Virginia (November 2024), which RRA reports as 9.75%, not 9.80%, and Florida Public Utilities Co. (March 2025), which RRA reports as 10.20%, not 10.15%. He also includes an authorized ROE of 9.50% for Appalachian Power Company's 2023 case (PUR-2023-00002), though RRA lists the authorized ROE as "NA."

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1 43 percent of authorized ROEs for vertically integrated electric utilities since
2 January 2025 have been 9.90 percent or higher.²¹⁰

3 With respect to Mr. Lyon's assertion that Michigan's regulatory framework reduces
4 DTE Electric's risk, I note that Mr. Lyon does not compare DTE Electric's
5 regulatory framework to the proxy group. As explained in my Direct Testimony,
6 evaluating risk is a comparative exercise and forward test years and capital cost
7 recovery mechanisms are also in place for the proxy companies. Because the proxy
8 companies all have similar mechanisms, DTE Electric is no less risky than its peers
9 and any effects on the cost of equity associated with the regulatory framework are
10 captured in the analytical model results.²¹¹

11

12 **Q132. Do you agree with Walmart Witness Lyon that your ROE recommendation is**
13 **too high?**²¹²

14 A132. No, I do not. Table 15 below lists recent authorized ROEs for vertically
15 integrated electric utilities above 9.90 percent, which is the low end of my
16 recommended range. As Table 15 shows, Mr. Lyon excluded three 2023 decisions
17 in California that range from 10.65 percent to 10.75 percent. Since that time,
18 interest rates have increased considerably, as discussed earlier in my testimony.
19 Furthermore, there are at least 27 utilities with current authorized ROEs above 9.90
20 percent, the low end of my recommended ROE range. Thus, my 10.75 percent
21 recommendation is reasonable.

²¹⁰ Source: Regulatory Research Associates.

²¹¹ Direct Testimony of Jennifer E. Nelson, page 56, lines 10-12.

²¹² Direct Testimony of Matthew T. Lyon, page 10, lines 3-4.

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**Table 15 Authorized ROEs of at Least 9.90%
For Vertically Integrated Electric Utilities (2023-2025)²¹³**

Company	State	Date of Order	Authorized ROE
Alaska Electric Light Power	Alaska	8/31/2023	11.45%
Southern California Edison Co.	California	12/22/2023	10.75%
Pacific Gas & Electric Co.	California	12/22/2023	10.70%
San Diego Gas & Electric Co.	California	12/22/2023	10.65%
Tampa Electric Co.	Florida	12/3/2024	10.50%
Southern California Edison Co.	California	10/17/2024	10.33%
Duke Energy Florida LLC	Florida	8/21/2024	10.30%
Pacific Gas & Electric Co.	California	10/17/2024	10.28%
San Diego Gas & Electric Co.	California	10/17/2024	10.23%
Florida Public Utilities Co.	Florida	3/4/2025	10.20%
Duke Energy Carolinas LLC	North Carolina	12/15/2023	10.10%
Otter Tail Power Co.	North Dakota	12/30/2024	10.10%
Liberty Utilities (CalPeco Electric)	California	4/27/2023	10.00%
PacifiCorp	California	12/14/2023	10.00%
Bear Valley Electric Svc Inc	California	1/16/2025	10.00%
Green Mountain Power Corp.	Vermont	8/26/2024	9.97%
Virginia Electric & Power Co.	North Carolina	1/14/2025	9.95%
Duke Energy Carolinas LLC	South Carolina	6/20/2024	9.94%
Dominion Energy South Carolina	South Carolina	8/8/2024	9.94%
Consumers Energy Co.	Michigan	1/19/2023	9.90%
Upper Peninsula Power Co.	Michigan	3/24/2023	9.90%
DTE Electric Co.	Michigan	12/1/2023	9.90%
Consumers Energy Co.	Michigan	3/1/2024	9.90%
AES Indiana	Indiana	4/17/2024	9.90%
Puget Sound Energy Inc.	Washington	1/15/2025	9.90%
Consumers Energy Co.	Michigan	3/21/2025	9.90%

3
4
5
6
7

I further note that on July 1, 2025 the Georgia Public Service Commission approved a settlement for Georgia Power Company that would extend its Alternative Rate Plan for three years in lieu of filing a rate case and maintained Georgia Power Company's 10.50 percent ROE (within a range of 9.50 percent to 11.90 percent)

²¹³ Source: Regulatory Research Associates.

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1 and 56 percent equity ratio.²¹⁴ Because Georgia Power Company did not file a rate
2 case, this decision is not included in RRA's dataset. Additionally, Florida Power
3 & Light recently filed a settlement reached with several parties that stipulated to a
4 10.95 percent ROE within a range of 9.95 percent to 11.95 percent and an equity
5 ratio of 59.60 percent. Walmart is a party to the stipulation as is Federal Executive
6 Agencies, whose witness is Mr. Walters.²¹⁵ A consortium of consumer parties filed
7 a separate settlement that proposed a 10.60 percent ROE within a range of 9.6
8 percent to 11.6 percent on 59.60 percent equity ratio.²¹⁶

9 **Response to MNC Witness Jester**

10 **Q133. Mr. Jester asserts that persistent disallowances do not increase regulatory**
11 **risk.²¹⁷ Do you agree?**

12 A133. No, I do not. I agree that cost recovery is not guaranteed and that the Company
13 bears the burden of demonstrating its costs are prudently incurred. Mr. Jester points
14 to credit rating agencies' descriptions of the Michigan regulatory environment as
15 currently supportive. Persistent disallowances, however, would adversely affect
16 the financial community's views of Michigan's regulatory environment, rendering
17 it less supportive compared to other regulatory environments. Because the
18 Company must compete for capital among utilities that operate in as supportive or
19 more supportive regulatory environments, persistent disallowances would
20 jeopardize the perception of the supportiveness of Michigan's regulatory
21 environment. If debt and equity investors determine that cost recovery in Michigan

²¹⁴ <https://www.georgiapower.com/news-hub/press-releases/georgia-psc-approves-plan-to-freeze-base-rates-through-2028.html>

²¹⁵ Florida Public Service Commission Docket No. 20250011-EI, Joint Motion for Approval of Settlement Agreement, at 3 (August 20, 2025).

²¹⁶ Florida Public Service Commission Docket No. 20250011-EI, Joint Motion to Approve Customer Majority Parties' Stipulation and Settlement Agreement, at 4 (August 26, 2025).

²¹⁷ Direct Testimony of Douglas B. Jester, page 12, lines 5-11.

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1 is becoming more unpredictable or uncertain, the Company's regulatory risk will
2 increase and investors will demand a higher return to compensate them for taking
3 on additional risk.
4

5 **Q134. What is your response to Mr. Jester's assertion that if disallowances increase**
6 **the Company's risk, the allowed ROE should not increase "above its market-**
7 **determined cost of capital?"²¹⁸**

8 A134. I agree that the authorized return should reflect the market cost of equity. I have
9 estimated the Company's market cost of equity through the use of various market
10 based financial models. Further, I do not make any adjustments to account for the
11 risk of disallowances or regulatory risk. To the extent that Mr. Jester is suggesting
12 that the Company's requested ROE is above its market determined cost of equity,
13 he is incorrect. Nevertheless, as discussed earlier, if debt and equity investors
14 determine that cost recovery in Michigan is becoming more unpredictable or
15 uncertain, its market cost of equity will increase because investors will demand a
16 higher return to compensate for higher regulatory risk.

17 **Capital Structure**

18 **Q135. Please summarize the capital structure recommendations of the Opposing**
19 **Witnesses.**

20 A135. All of the Opposing Witnesses recommend a capital structure consisting of 50
21 percent common equity and 50 percent debt. As discussed in my Direct Testimony,
22 regulatory guidelines recommend that a Company's ratemaking capital structure
23 reflect its actual capital structure when three criteria are met: the subject utility (1)
24 issues its own debt; (2) has its own credit rating; and (3) its actual capital structure
25 is consistent with the proxy group's capital structure. As explained in my Direct

²¹⁸ Direct Testimony of Douglas B. Jester, page 14, lines 3-11.

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1 Testimony, the Company's proposed capital structure meets all three criteria and
2 should be approved. Mr. Lepczyk responds to the Opposing Witnesses' capital
3 structure recommendations.
4

5 **Q136. Mr. Coppola and Mr. Walters reference the capital structures of the proxy**
6 **group at the consolidated holding company level.²¹⁹ Are comparisons to the**
7 **capital structure at the holding company level the correct measure of an**
8 **appropriate capital structure for a regulated electric utility?**

9 A136. No, they are not. As a preliminary matter, the rate base – rate of return regulatory
10 construct is grounded in the recognition that a utility's rate base on the asset side of
11 the balance sheet is financed with the subject utility's capital structure included on
12 the liabilities and equity side of the balance sheet. For that reason, the actual capital
13 structure should be used unless it is demonstrated that it greatly diverges from
14 sound industry practice. DTE Electric's 50.75 percent equity ratio is less than the
15 average proportion of equity used by its peers as Mr. Lepczyk's Exhibit A-14
16 Schedule D1.1 shows. Therefore it is not unsound or unreasonable.
17 Consolidated holding companies do not have an obligation to serve and are,
18 therefore, financed differently than their regulated operating subsidiaries. Unlike
19 the parent company, regulated operating subsidiaries must maintain financial
20 flexibility to meet the obligation to serve in all operating and market environments.
21 That financial flexibility has a cost. Capital at the holding company level finances
22 a variety of business segments (both regulated and unregulated) each with different
23 risk profiles and return requirements. For these reasons, the proper comparison of

²¹⁹ Direct Testimony of Sebastian Coppola, page 72, lines 16-17; and Direct Testimony of Christopher C. Walters, page 22, lines 3-7.

Line
No.

1 the Company's capital structure is to the capital structures that finance the proxy
2 companies' *regulated* electric operations.

3

4 **Q137. Mr. Bandyk performs an interest coverage ratio analysis to support his**
5 **recommendation.²²⁰ Do you agree with his analysis and the conclusions he**
6 **draws from it?**

7 A137. No, I disagree with his analysis for several reasons. First, the interest coverage
8 ratio that Mr. Bandyk uses is not used by the rating agencies for the utilities sector.
9 Mr. Bandyk refers to Dr. Damodaran's data of corporate interest coverage ratios
10 and bond ratings, however, this data is not specific to the utilities sector and reflects
11 non-regulated sectors without the obligation to serve. For the utilities sector
12 specifically, the rating agencies focus on measures of cash flow to debt and debt
13 leverage as the primary metrics.²²¹
14 Most notably, however, even if Mr. Bandyk's analysis was the exact methodology
15 applied by the rating agencies (which it isn't), Mr. Bandyk's analysis shows that
16 the Company's requested return results in an interest coverage ratio of 4.58 that
17 falls in his purported A2 credit rating range (4.25 to 5.499), which is the Company's
18 current rating. His recommendation produces an interest coverage ratio of 3.82,
19 which falls in his purported A3 credit rating range (3.00 to 4.249). In other words,
20 Mr. Bandyk's own analysis shows that his recommendation would be insufficient
21 to meet his purported interest coverage ratio for an A2 rated entity like DTE

²²⁰ Direct Testimony of Matthew J. Bandyk, page 35, lines 1-19; and page 36, lines 1-17; Exhibit CUB-9.

²²¹ For example, S&P's primary metrics are Funds From Operations ("FFO")/Debt and Debt/Capitalization. Moody's primary metrics are Cash From Operations pre-working capital ("CFO pre-WC")/Debt, CFO pre-WC less dividends/Debt, and Debt/Book Capitalization.

Line
No.

1 Electric. The Company's requested ROE and capital structure produces an interest
2 coverage ratio that is in the lower half of the A2 range reported by Mr. Bandyk.

3 **Updated ROE Analysis**

4 **Q138. Have you updated your ROE analyses?**

5 A138. Yes, I have updated the results of the financial models used to estimate the cost of
6 equity for DTE Electric in my direct testimony (data as of January 31, 2025) to
7 include market data through July 31, 2025. I have updated the proxy group to
8 remove TXNM, Inc. and Northwestern Energy Group from my proxy group due to
9 pending transactions. Additionally, I have added Dominion Energy, Inc. because
10 enough time has passed since the closing of the sale of its natural gas distribution
11 utilities to Enbridge, Inc. The results of the updated analyses are shown in Table 16
12 and Exhibit A-39 Schedule DD2.1 to Exhibit A-39 Schedule DD2.5.

Line
No.

1

Table 16 Updated ROE Results²²²

Model	January 31, 2025	July 31, 2025
Constant Growth DCF	10.33%	10.48%
Quarterly Growth DCF	10.59%	10.69%
<i>Average DCF</i>	<i>10.46%</i>	<i>10.58%</i>
CAPM: Forward Market Return	14.33%	12.07%
CAPM: Historical Market Return	11.49%	10.03%
ECAPM: Forward Market Return	14.57%	12.81%
ECAPM: Historical Market Return	11.66%	10.57%
<i>Average CAPM</i>	<i>13.01%</i> <i>(11.58% average low CAPM)</i>	<i>11.37%</i>
<i>Risk Premium</i>	10.28%	10.31%
ROE Recommendation	10.75%	10.75%

2

3 **Q139. How do these updated results compare with those presented in your direct**
4 **testimony?**

5 A139. The updated data increased the results of the DCF to approximately 10.60 percent.
6 The Risk Premium results remained approximately the same at 10.30 percent. The
7 updated data for the CAPM produced results ranging from approximately 10.00
8 percent to 12.80 percent and average approximately 11.30 percent. My 10.75
9 percent ROE recommendation falls below the midpoint of the range and is equal to
10 the average of the updated DCF, CAPM, and Risk Premium results.

²²² See, January 31, 2025 Results: Exhibit A-14 Schedule D5.1 to Exhibit A-14 Schedule D5.5. CAPM results as corrected in Exhibit A-39 Schedule DD2.6. July 31, 2025 Results: Exhibit A-39 Schedule DD2.1 to Exhibit A-39 Schedule DD2.5. DCF results reflect only the results using the mean EPS growth rates. DCF and CAPM results reflect the average of the proxy group mean and median ROE estimates.

Line
No.

1 **Conclusion**

2 **Q140. Please summarize your key conclusions and recommendations.**

3 A140. As discussed in my Direct and Rebuttal Testimonies, it is critical that the Company
4 maintain its financial profile in order to provide safe, reliable service to the benefit
5 of customers. The Opposing Witnesses' recommendations are unduly low and
6 would not provide a risk-comparable return, impeding DTE Electric's ability to
7 maintain a strong financial profile and attract capital. Based on the analyses
8 discussed throughout my Rebuttal Testimony, my 10.75 percent ROE
9 recommendation remains a reasonable and appropriate estimate of the Company's
10 cost of equity. The results of the updated DCF, CAPM, ECAPM, and Bond Yield
11 Plus Risk Premium analyses, along with my analyses of capital market data and the
12 Company's risk profile, continue to support the reasonableness of my 10.75 percent
13 ROE recommendation. I further continue to support the proposed capital structure
14 consisting of 50.75 percent common equity and 49.25 percent long-term debt.

15

16 **Q141. Does this conclude your rebuttal testimony?**

17 A141. 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

REBUTTAL TESTIMONY

OF

MARKUS B. LEUKER

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF MARKUS B. LEUKER

Line
No.

1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed?**

3 **A1.** My name is Markus B. Leuker. My business address is: One Energy Plaza, Detroit,
4 Michigan 48226. I am employed by DTE Electric Company (DTE Electric or
5 Company) as a Director of Load Management and Forecasting in the Business
6 Planning and Development organization.

7

8 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
9 **Company (DTE Electric or Company)?**

10 **A2.** Yes.

11

12 **Purpose of Testimony**

13 **Q3. What is the purpose of your rebuttal testimony?**

14 **A3.** The purpose of my rebuttal testimony is to:

15 1. Address the following Load Forecasting topics:

- 16 • Respond to the assertion of Attorney General (AG) Witness Coppola that
17 the Electric Vehicle (EV) adoption forecast is too high.
- 18 • Respond to the request for Circuit level loading analysis to be modeled
19 under different electrification scenarios, as proposed by Witness Woolley
20 on behalf of Michigan Environmental Council (MEC), Natural Resources
21 Defense Council (NRDC), Sierra Club (SC) and Citizens Utility Board of
22 Michigan (CUB) collectively MNSC and Witness Stephens on behalf of the
23 AG and Michigan Environmental Council, and Natural Resources Defense
24 Council (MN) or collectively AG-MN.

Line
No.

- 1 • Address MSNC Witness Woolley’s recommendation that the Company
- 2 develop an EV detection tool.
- 3 • Respond to AG-MN Witness Stephens’ criticism regarding the accuracy of
- 4 the load forecasts.
- 5 • Respond to Michigan Public Service Commission (MPSC or Commission)
- 6 Staff (Staff) Staff Witness Ausum’s recommendations regarding the Rate
- 7 Case Electric Filing PIII Supplemental Data requirements.
- 8 2. Address the following Demand Response (DR) topics:
- 9 • Respond to testimony of Staff Witness Towslee regarding the disallowance
- 10 associated with the dedicated DR call center;
- 11 • Respond to the testimony of Witness Matthews of the MPSC Staff and
- 12 Witness Sherman on behalf of Michigan Energy Innovation Business
- 13 Council (MEIBC), Institute for Energy Innovation (IEI), and Advanced
- 14 Energy United (United), collectively referred to as MEIU on the Company’s
- 15 Commercial and Industrial (C&I) Battery Storage DR Pilot and the
- 16 proposed disallowance;
- 17 • Respond to testimony of The City of Ann Arbor (AA) Witness Lange
- 18 regarding the Company’s residential generator DR pilot;
- 19 • Address MNSC Witness Woolley’s recommendation to make Smart Charge
- 20 a permanent program within the DR portfolio;
- 21 • Address the recommendations of MEIU Witness Albers on the Company’s
- 22 DR Procurement;
- 23 • Address the proposed Operations and Maintenance (O&M) disallowance of
- 24 AG Witness Coppola.

Line
No.

- 1 • Address recommendations of Ecology Center, The Environmental Law and
2 Policy Center, The Union of Concerned Scientists and Vote Solar,
3 collectively CEO, witness Kenworthy regarding Virtual Power Plants
4 (VPP).

5

6 The absence of a discussion of other matters in my testimony should not be
7 regarded as an indication that I agree with all other aspects of the Staff's and
8 intervenor's testimony. The narrow focus of my testimony is instead a consequence
9 of a focus on priority issues in recognition of the available resources.

10

11 **Q4. Are you sponsoring any exhibits in this proceeding?**

12 **A4.** No.

13

14 **Load Forecasting Topics**

15 **Electric Vehicle Forecast**

16 **Q5. What did AG Witness Coppola say in his testimony regarding the DTE**
17 **Electric EV registration forecast?**

18 **A5.** On page 31, line 8 of his direct testimony, Witness Coppola states, "Although the
19 Company continues to show "hockey stick" growth in EV registrations and
20 adoptions for future years in the testimony of Mr. Neal Foley in this rate case, the
21 rate of new vehicle registrations has slowed down significantly in the past year."

22

23 **Q6. Does the Company agree with Witness Coppola?**

24 **A6.** No. First, the Company does not agree with AG Witness Coppola's characterization
25 of the EV registration forecast as "hockey stick" growth. Second, EV registrations

Line
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1 have been higher than forecast in the second half of 2024 and the first half of 2025,
2 contrary to Witness Coppola's assertion that the rate of new vehicle registrations
3 has slowed down significantly in the past year.

4

5 **Q7. What have the EV registrations been in the DTE Electric service area over the**
6 **past year?**

7 **A7.** EV registrations have been at all-time highs over the last 12 months. The Company
8 currently has registration data up through June 2025. From July 2024 to June 2025,
9 there have been 44,761 registrations in the DTE Electric Service Area compared to
10 18,421 registrations from July 2023 to June 2024. See Figure 1 below.

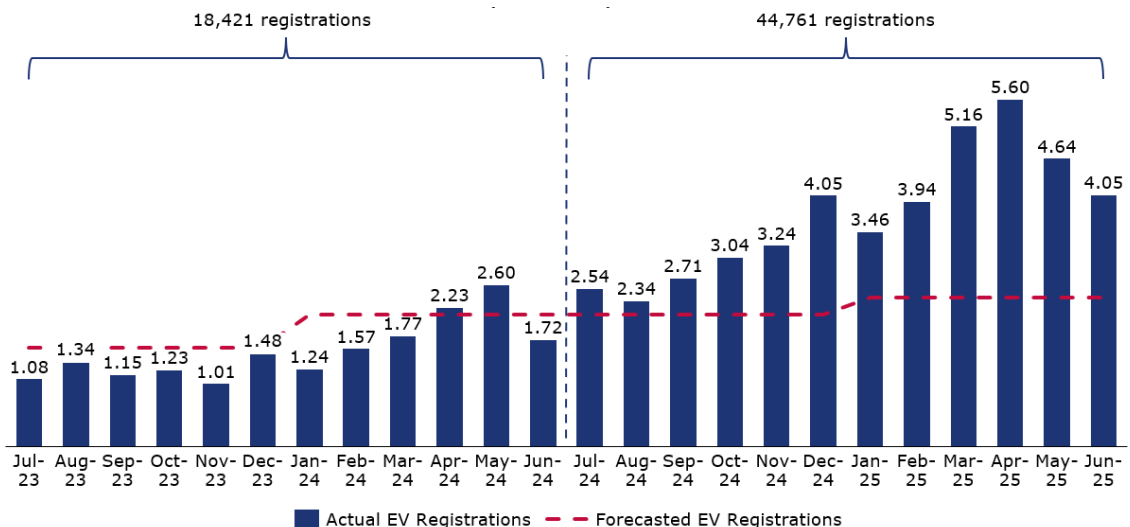
11 The rate of new EV registrations has increased in the past 12 months in contrast to
12 Witness Coppola's incorrect assertion that the rate of new vehicle registrations has
13 slowed down significantly in the past year.

14

15 **Figure 1 Actual Total EV Registrations in DTE Electric Service**

16 **Territory (thousands)**

17



Line
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1 **Q8. What else does AG Witness Coppola testify to regarding the EV market?**

2 **A8.** In his direct testimony, page 31, starting at line 11, Witness Coppola states,
3 “Beginning in 2024, EV manufacturers realized that electric vehicles are not selling
4 at the pace anticipated as late as 2023, and EVs are stockpiling at dealers’ lots. EV
5 buyers often have been dissatisfied with the actual driving range, particularly
6 during the winter and hot days that quickly drain the car batteries. Reliability of
7 certain vehicles with recalls for software and equipment failures has also created
8 customer dissatisfaction and increased concerns and fear with prospective EV
9 buyers. EV manufactures have cut back production of EVs, delayed new models,
10 deferred building new batteries plants, and redirected resources to hybrid vehicles
11 with batteries that self-charge during gasoline-fueled operation.”

12

13 **Q9. Does the Company agree with the way AG Witness Coppola characterizes the**
14 **EV market and that EV adoption may not materialize at the rate the Company**
15 **has proposed?**

16 **A9.** No. The Company disagrees with Witness Coppola’s characterization. There is
17 ample evidence to support the Company’s projections of EVs that were used as the
18 basis for various investments in this instant case. Witness Coppola characterizes
19 the EV market in a way that makes it seem like the EV market is in decline, but this
20 is not true. Despite forecast revisions made by the Company with each iteration as
21 Witness Coppola points out, it is still the Company and external experts’¹ opinion
22 that the market for EVs will continue to grow. Said differently, there will continue
23 to be new EVs added to the Company’s service area each year that the Company
24 will be required to serve, even if that growth is slower than previous projections.

¹ [Quantifying Trump’s impacts on EV adoption - The Salata Institute](#)

Line
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1 **Q10. What do other witnesses in this case say about the EV forecast?**

2 **A10.** MEIU Witness Schuster testifies on page 11, lines 4-6 of her direct testimony, that
3 she agrees with the EV deployment rate predicted by the Company.
4

5 **Q11. What are the implications of the higher EV registrations over the last year?**

6 **A11.** The Company attributes the increase in EV registrations over the past year to the
7 availability of federal tax credits. The federal EV tax credits are scheduled to be
8 eliminated as part of the One Big Beautiful Bill Act (OBBBA), so the future EV
9 registrations remain somewhat uncertain into the 2026 test year for this instant case.
10 With the additional EV registrations over the past year, we are currently ahead of
11 forecast in 2025, making the 2025 forecast underestimated instead of overestimated
12 as Witness Coppola insinuates on page 30, lines 15-16 of his direct testimony.
13 Despite the uncertainty going into 2026, the strong EV sales performance of 2025
14 along with the likelihood that these vehicles will remain in DTE's service area and
15 require charging support, it is unlikely that the 2026 forecast for EV charging is
16 overestimated.
17

18 **Q12. What is your recommendation related to the EV forecast?**

19 **A12.** Consistent with Company Witness Foley's support and MEIU Witness Schuster's
20 recommendation, I recommend the Commission accept the Company's EV forecast
21 as filed.
22

23 Circuit Level Forecasting

24 **Q13. What did AG-MN Witness Stephens and MSNC Witness Woolley request**
25 **regarding a Circuit level loading analysis?**

Line
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1 **A13.** AG-MN Witness Stephens’ second recommendation, found on page 70 of his direct
2 testimony, states the Company should “Implement a circuit-specific load
3 forecasting capability before DTE’s next rate case” and on page 29, line 2 of his
4 direct testimony, MNSC Witness Woolley’s seventh recommendation states the
5 Commission should “Require the Company to submit circuit- and substation-level
6 loading and thermal headroom analyses (similar to the one I present at the network-
7 level), modeled under multiple electrification scenarios and tied to clear upgrade
8 triggers, in support of any grid plan or capacity project that it seeks to justify on the
9 basis of system loading.”

10

11 **Q14. What is your response to these Witnesses’ recommendations for circuit**
12 **loading studies?**

13 **A14.** In the order issued on July 10, 2025 in Case U-20147, distribution system plan
14 (DSP) filing guidelines were issued². As part of those guidelines, action plans shall
15 include:

16

17 *“a. Load Forecasts, Scenario Planning, and DER Outlook*

18 *The utility shall describe its circuit-level load forecasting process,*
19 *including how the utility incorporates the load-modifying impacts*
20 *of DERs. For each of its distribution circuits, the utility shall*
21 *provide the circuit voltage, capacity (MW or MVA), the peak and*
22 *minimum daytime load for each of the previous five years, the*
23 *forecasted peak load, MW of existing DERs by DER type, and*
24 *forecasted MW of DERs by DER type. In developing its load*
25 *forecasts, the utility shall consider multiple scenarios, including at*
26 *a minimum lower and higher levels of building and transportation*
27 *electrification”*

² [STATEOFMICHIGAN](https://www.stateofmichigan.gov/energy/2025/07/10/dsp-filing-guidelines)

Line
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1 The Company intends to comply with the above recent order. In the next DSP, the
2 Company plans to utilize circuit level load forecasts that consider multiple
3 electrification scenarios. The Company's position is that the DSP is the correct
4 place for the presentation of the circuit level forecasts and scenario planning.

5

6 Electric Vehicle Detection

7 **Q15. What did MNSC Witness Woolley recommend regarding EV detection?**

8 **A15.** On page 5, lines 12-15 of his direct testimony, Witness Woolley states, "First, the
9 Company should identify which residential customers have EVs. With the help of
10 existing EV detection tools, the Company can use customer metering data to
11 identify customers that charge EVs at home, even if the EV purchase and/or the
12 installation of home charging infrastructure occurred without the Company's
13 knowledge."

14

15 **Q16. How do you respond to MNSC Witness Woolley's recommendation regarding**
16 **EV detection?**

17 **A16.** I agree with Witness Woolley that EV detection or EV finder tools are valuable for
18 a utility to ascertain which customers are charging EVs at their residences. The
19 Company is already developing an EV Identification Framework which includes
20 an EV finder tool in-house for this use. The Company is in the late stages of
21 development and is planning for the results from the DTE Electric-developed EV
22 Identification Framework to be used in the circuit level loading analysis described
23 above and planned for the next DSP. There will be no need for the Company to
24 investigate or purchase a separate EV detection tool.

Line
No.

1 Forecast Accuracy

2 **Q17. What did AG-MN Witness Stephens say regarding the System wide load**
3 **forecast?**

4 **A17.** On page 42, lines 1-6, Witness Stephens states, “I note that the load growth DTE
5 forecasted in its 2022 Integrated Resource Plan was not at all accurate. To me, this
6 calls the accuracy of DTE’s load growth forecasting process into question,
7 particularly given DTE’s failure to maintain a capability to forecast loads at the
8 circuit level. A bottom-up (by circuit) load forecasting process would undoubtedly
9 be more accurate than the top-down load forecasting process DTE has employed to
10 date.”

11

12 **Q18. How do you respond to AG-MN Witness Stephens?**

13 **A18.** Witness Stephens selected the incorrect forecast from the DTE Electric 2022
14 Integrated Resource Plan (IRP) filing from which to evaluate the Company’s
15 forecast accuracy. In that IRP case, the Company presented a total of nine load
16 forecasts including all the required sensitivities. The load forecast selected for
17 Witness Stephens’ analysis was the “high load forecast” and was developed to
18 satisfy the requirement of 1.5% load growth rate on energy or peak demand per
19 year as specified in the MIRPP filing requirements in place for that case. It is
20 inappropriate to select that high load forecast sensitivity to be representative of the
21 Company’s load forecasting accuracy.

22

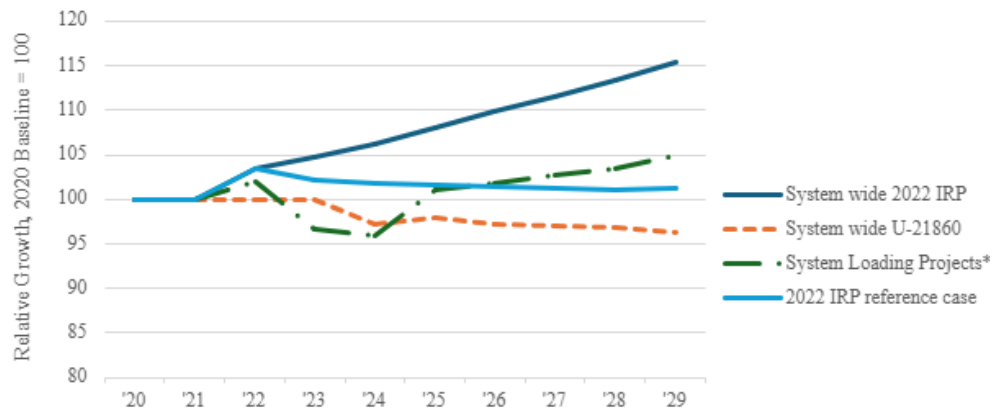
23 In addition, Witness Stephens used incorrect values³ for the years 2020 and 2021
24 in Figure 9 of his testimony, rendering the graphic and his assertions that “the load

³ Witness Stephens used values 10,630 and 11,005 for 2020 and 2021 respectively. The correct values are 11,005 and 10,992 for 2020 and 2021 respectively.

Line
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1 growth DTE presented in its 2022 Integrated Resource Plan was not at all accurate”
2 as misleading and a gross mis-characterization of the reference case forecast that
3 should have been used in his analysis. Refer to Figure 2 that shows the corrected
4 values⁴ for 2020 and 2021 as well as the 2022 IRP Reference Case forecast instead
5 of the high-load forecast (System wide 2022 IRP).

7 **Figure 2: Corrected Witness Stephens Figure 9 – Load Growth System-
8 Wide vs. System Loading**



9
10 **Q19. Can you discuss the accuracy of the load forecast over the last few rate case**
11 **filings?**

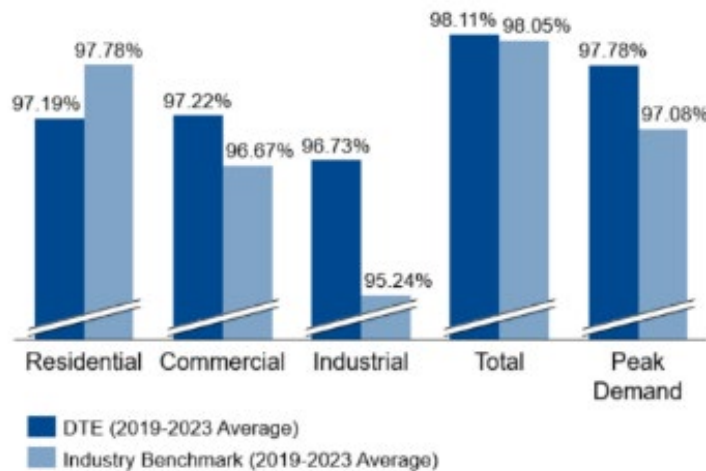
12 **A19.** As seen in Figure 2, the Company’s load forecast accuracy is much higher than
13 Witness Stephens notes, and in line with industry benchmarks. The Company has
14 provided forecast accuracy data in this instant case. As seen in my exhibit A-15,
15 Schedule E5, page 1, lines 22 and 23, the peak demand variance is 2.22% on
16 average for 2019-2023 and 2.49% for 2022-2024. DTE Electric compares favorably
17 to other peer utilities across the nation in the ITRON benchmarking study over the

⁴ 2020 and 2021 values are actual, not weather-normalized

Line
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1 years of 2019-2023, as shown in my direct testimony on page 38-39, starting on
2 line 12, and in Figure 3. Similar accuracy comparisons have been presented in the
3 last few rate cases.

5 **Figure 3 DTE vs. Industry Forecast Accuracy 2019-2023**



7 Changes to PIII Supplemental Data Attachment 3 Requirements

8 **Q20. What proposals did Staff Witness Ausum make regarding the Rate Case Filing**
9 **Requirements?**

10 **A20.** Staff Witness Ausum proposes revisions to the Rate Case Filing Requirements,
11 specifically Part III Supplemental Data. Witness Ausum requests that Attachment
12 3 Question 1 be updated to require "...actual historical customer class sales, number
13 of customers, and monthly use per customer alongside the rate schedule sales."
14 Additionally, Witness Ausum proposes that Attachment 3 Question 1 and 2 be
15 revised so that the data "correspond[s] with the sample of historical data used to
16 estimate the forecasting regression equations which in this case was the period
17 beginning January 2006 through June 2024".

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1 **Q21. Should adjustments to Part III Supplemental Data be made within individual**
2 **rate case proceedings?**

3 **A21.** No. The rate case filing requirements extend to all Michigan utilities. Therefore,
4 any changes should be made through the appropriate regulatory docket to allow all
5 utilities and interested parties to have a voice. Most recently, in U-18238, the
6 Commission updated the filing requirements—including Part III Supplemental
7 Data, which concluded in July 2024 after more than a year of collaborative
8 stakeholder engagement.

9
10 **Q22. Beyond procedural concerns, are there substantive issues with Staff Witness**
11 **Ausum's recommendations?**

12 **A22.** Yes. Witness Ausum's recommendation to extend the reporting period back to 2006
13 to align with the load forecasting model is not feasible and does not align with the
14 Company's forecasting methodology. The Company forecasts deliveries at the
15 customer class level, not the rate schedule level. The Company's data from that
16 period is not consistently aligned at the rate schedule level and predates the
17 implementation of Advanced Metering Infrastructure (AMI), during which data
18 collection and summarization practices differed significantly.

19
20 Additionally, extending the reporting period for individual attachments through the
21 most recent calendar years could lead to historical mismatches. If Staff Witness
22 Ausum is seeking the inputs to the Company's load forecasting model, those inputs
23 are provided regularly through Audit and in this instant case the Company provided
24 complete model inputs as well as forecasting project files when requested by Staff.

Line
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1 The Company is willing to provide its forecasting model inputs as workpapers if
2 desired by the Commission in its next Rate Case Filing.

3

4 **Demand Response Topics**

5 **DR Call Center**

6 **Q23. Could you describe the dedicated DR call center?**

7 **A23.** Yes. The dedicated DR call center was set up to field DR specific calls from
8 customers. The call center is operated by an external vendor and is shared with
9 various groups within DTE Electric such as Energy Waste Reduction, Home
10 Protection Plus and Natural Gas Balance. The Company projects \$300,000 in
11 annual O&M expenses to support the DR call center.

12

13 **Q24. What recommendation did Staff Witness Towslee make regarding the**
14 **dedicated DR call center?**

15 **A24.** Beginning on page 3 of his direct testimony, Witness Towslee recommends the
16 Commission disallow the projected \$300,000 annual cost to support the call center.

17

18 **Q25. What reasons does Staff Witness Towslee cite for his recommendation to**
19 **disallow the costs associated with the DR call center?**

20 **A25.** The first reason Witness Towslee cites is that the Company has not previously
21 sought approval regarding the call center (p. 3, Lines 17-18). In addition, Witness
22 Towslee argues that Staff is not convinced that the DR call center is necessary
23 because the volume of DR related calls are not tracked by the Company's general
24 call center nor did the Company provide evidence to support the service (Towslee,
25 p. 4, Lines 1-5).

Line
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1 **Q26. How do you respond to Staff Witness Towslee's reasons for disallowance?**

2 **A26.** The Company did seek approval to recover DR call center costs in the Company's
3 last ordered electric rate case, Case No. U-21534. The call center is included in the
4 Other Projects line item of Table 3 and is mentioned specifically on page 42 of
5 Company Witness Farrell's direct testimony in case U-21534. In that case, no
6 intervenors nor Staff took issue with the proposed spend.

7
8 **Q27. Why does the Company believe that the DR call center is necessary?**

9 **A27.** The dedicated call center allows the Company to respond to the dynamic needs of
10 DR programs and DR events. The dedicated call center allows for specialized
11 training and dedicated DR subject matter experts. By having dedicated DR subject
12 matter experts, calls can be resolved more quickly, which reduces the number of
13 escalations to program managers, improving first call resolution metrics. As
14 indicated on page 4 of Staff Witness Towslee's exhibit S-20.1, the Company
15 conducted an exercise to identify DR-related calls to the general call center and
16 determined an accuracy factor. Based on this exercise, the dedicated DR call center
17 was able to reduce call handling time by an average of nearly 46% compared to the
18 general call center. By reducing call handling time, the Company will be enhancing
19 the overall customer experience—streamlining enrollment and boosting retention
20 in DR programs. Through July 2025, the dedicated call center received 2,530 calls
21 related to demand response that have been transferred from the general call center
22 and has fielded 6,594 calls where customers called the DR call center directly.

23

24 In addition, with anticipated increased focus on program growth within the
25 residential sector and the expectation that more DR events will be called in the

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1 future, having a dedicated DR call center is necessary to resolve customer issues
2 and answer customer questions efficiently.

3

4 **Q28. Should the Commission disallow the costs associated with the dedicated DR**
5 **call center as recommended by Staff Witness Towslee?**

6 **A28.** No. For the reasons outlined, it is essential that the Commission approve the
7 forecasted spend for the dedicated DR call center to ensure the Company continues
8 to deliver a positive customer experience for those enrolled and participating in
9 demand response programs.

10

11 C&I Battery Storage DR Pilot

12 **Q29. What is the Company's C&I battery storage DR pilot?**

13 **A29.** The C&I battery storage pilot is a behind-the-meter (BTM) lithium-ion phosphate
14 battery energy storage system (BESS) that is designed to test the ability to achieve
15 peak demand shaving or shifting during a DR event. The Company is targeting a
16 two-year pilot after installation is completed at two customer sites. The Company
17 has identified one external commercial customer and one internal customer.

18

19 **Q30. What recommendation did Staff Witness Matthews make on the Company's**
20 **C&I battery storage DR pilot?**

21 **A30.** Beginning on page 7, line 3 of his testimony, Witness Matthews recommends that
22 the Commission disallow the costs associated with the second battery of roughly
23 \$508,000 "at this time". In addition, he states the Staff is supportive of the Company
24 looking for other uses for the second battery, and recognizes there are many benefits
25 when a battery is used in conjunction with a substation or Non-Wires Alternative

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1 (NWA) project but recommends looking for pilots that are not similar to other
2 Company approved storage pilots (p.6, lines 15-18, p.7, lines 18-21). He concludes
3 by recommending the Company's use case should be different than its current
4 NWA pilots.

5

6 **Q31. How do you respond to Staff Witness Matthews' recommendation that the**
7 **Commission should disallow the costs associated with the second battery?**

8 **A31.** The Company disagrees with the proposed disallowance. Witness Matthews'
9 recommendation appears to be based on the misunderstanding that the battery will
10 be used for NWA purposes. Despite the second battery being used by an internal
11 customer, the battery will not be used for NWA purposes (e.g., preventing
12 substation overloading). Instead, it will be housed in a controlled environment that
13 allows for testing on the grid in a safe manner, with equipment that can perform
14 repeatable scenarios of expected events. This will allow for 1) experimentation and
15 stacking of different energy storage use cases, 2) evaluation of compensation
16 models, 3) answering key questions around wholesale market integration (as
17 contemplated by the Commission's Order in MPSC Case No. U-21032), in addition
18 to addressing the DR-related objectives as outlined in question 98 on page 55 of
19 my direct testimony. These learnings will be critical to optimizing the use of
20 batteries going forward and therefore, the capital costs associated with the second
21 C&I DR battery should be approved.

22

23 **Q32. Could you summarize MEIU Witness Sherman's reasoning for recommending**
24 **disallowance of the second battery in the C&I battery storage DR pilot?**

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1 **A32.** Yes. Witness Sherman bases her recommendation to disallow the costs of the
2 second battery on two reasons. The first is that the Company still went ahead and
3 purchased the second battery and associated equipment despite the Commission
4 disallowances of the second battery spend in previous rate cases (p. 16-25). The
5 second reason is that an internal business unit is not an appropriate customer for
6 this pilot as the overall objectives will not be able to be achieved (p. 9, lines 2 –
7 12).

8

9 **Q33. How do you respond to MEIU Witness Sherman's reasons to recommend**
10 **disallowance of the second battery?**

11 **A33.** The Company did not ignore the Commission's second battery cost disallowances
12 from previous orders as insinuated by Witness Sherman. As indicated in Question
13 100 on page 56 of my direct testimony, along with testimony in previous rate cases
14 on this same topic, both batteries were purchased together and at the same time.
15 The spending on the second battery is a result of milestone payments that were
16 agreed to during the procurement schedule that was agreed upon by the Company
17 and battery manufacturer prior to Commission disallowance.

18

19 In addition, the Staff and Commission have been consistent about the need for the
20 Company to find a second customer that is willing to participate in the pilot dating
21 back to Case U-21297. Nowhere in Staff's testimony or the Commission's orders
22 around the second battery spend was it specified that the second customer must be
23 external. As indicated on page 56 of my direct testimony and correctly referenced
24 in Witness Sherman's testimony, the Company has been unsuccessful in finding a
25 second external customer due to the costs and associated savings for the customer.

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1 As a result, the Company had to pivot and work to find an internal customer where
2 the learning objectives could still be studied and pilot benefits could be realized.
3 The Company was successful in this endeavor despite Witness Sherman's
4 disagreement with this approach. The Company believes that utilizing an internal
5 customer to study the outlined objectives of the C&I battery storage DR pilot is
6 appropriate and the costs should not be disallowed.

7

8 Residential Generator Pilot

9 **Q34. Could you summarize the residential generator pilot?**

10 **A34.** Yes. The residential home generator pilot launched in 2023 in collaboration with
11 Generac Grid Services with a target to enroll 200 customers. The Company began
12 calling events and analyzed the results in 2024. Based on the 2024 event results,
13 the Company planned to continue the pilot throughout 2025 before transitioning the
14 residential home generator pilot to a program in 2026.

15

16 **Q35. What is the current status of the residential home generator pilot?**

17 **A35.** As indicated in my response to discovery request MEIUDE-2.13 and filed as AA
18 Witness Lange's exhibit AA-2, Generac unexpectedly terminated the current pilot
19 in Q1 of 2025. As a result, the Company closed the pilot and unenrolled all pilot
20 participants.

21

22 **Q36. Does AA Witness Lange support the Company pursuing a residential home**
23 **generator pilot?**

24 **A36.** No, Witness Lange does not support the idea of a residential home generator pilot
25 and states he "would not support such a program if it involves shifting electric load

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1 to fossil gas-powered generators” (p. 5, lines 1-2). He ultimately recommends
2 disallowance of the \$532,000 of O&M.

3

4 **Q37. What reasons does AA Witness Lange use to justify his position on residential**
5 **home generator pilots?**

6 **A37.** Throughout his testimony, Witness Lange argues why the use of generators does
7 not support the Company’s climate goals.

8

9 **Q38. Does AA Witness Lange offer any alternatives for a similar pilot?**

10 **A38.** Yes. Beginning with Line 1 on page 5 of his direct testimony, Witness Lange states
11 that he would support a similar pilot if it shifted electric load to batteries rather than
12 generators that rely on fossil fuels.

13

14 **Q39. How do you respond to AA Witness Lange’s testimony?**

15 **A39.** While the Company appreciates Witness Lange’s recommendations, it should be
16 noted that the \$532,000 in O&M was tied to the residential home generator pilot
17 which later would have been used to support a full-scale program. Being that
18 Generac terminated the pilot, the Company is no longer requesting the O&M that
19 is tied to the residential home generator pilot.

20

21 In addition, it appears that Witness Lange does not completely understand the
22 residential home generator pilot. The pilot targeted customers who already own a
23 whole-home generator and made the decision to purchase one prior to being
24 contacted by the Company. The pilot was not incentivizing customers to purchase
25 and install a natural gas generator. It simply targeted customers who already owned

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1 the technology and requested DTE Electric shift their load to their generator during
2 DR events. The Company's use of these existing generators during emergency
3 situations would reduce the need for investment in other generating resources and
4 supports the Company's clean energy goals. Because of this, the Company may
5 revisit a residential home generator pilot as the Company views generators as a
6 viable option for demand response participation. The residential generator pilot
7 could serve as a basis for a program that uses other technologies in the future.

8

9 **Q40. What recommendation do you make to the Commission regarding the**
10 **residential home generator pilot?**

11 **A40.** The Company recognizes that the original O&M ask of \$532,000 for the residential
12 generator pilot is no longer needed at this time. However, the Company asks the
13 Commission to recognize the opportunity that exists within this space and to allow
14 the Company to revisit the pilot, or make the pilot a program, in the future and
15 receive the appropriate funding when requested.

16

17 Smart Charge Pilot

18 **Q41. Could you summarize the Smart Charge Pilot?**

19 **A41.** Yes. The Smart Charge pilot is an electric vehicle managed charging pilot where a
20 participant's vehicle charging is automatically managed such that charging occurs
21 during off-peak periods when the electricity cost is lowest and makes use of
22 available capacity on the system.

23

24 **Q42. What is the current status of the Smart Charge Pilot?**

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1 **A42.** As indicated on page 60 of my direct testimony, Smart Charge currently remains in
2 the pilot stage while additional value streams are being analyzed. The Company
3 extended contracts with WeaveGrid and ChargeScape through the end of 2026 to
4 continue analyzing these additional value streams.

5
6 **Q43. Does Witness MNSC Woolley support keeping Smart Charge in the pilot**
7 **stage?**

8 **A43.** No. Witness Woolley recommended that “the Commission direct the Company to
9 convert Smart Charge into a permanent program and invest in scaling it
10 aggressively” (p. 20, lines 9 – 11).

11

12 **Q44. What reasons does MNSC Witness Woolley use to justify their position on the**
13 **Smart Charge pilot?**

14 **A44.** Witness Woolley justifies their position by indicating that unmanaged charging
15 adds “substantial on-peak load” (p. 19, line 19) and that the pilot “often reduced
16 customer’s bills relative to unmanaged charging” (p. 17, lines 11 – 12), provides a
17 positive financial impact to the Company of “about \$47.82 per participating
18 vehicle” (p. 19, lines 5 – 6), and “avoids costly new peak demand and associated
19 system upgrades” (p. 19, line 21).

20

21 **Q45. Do you agree with MNSC Witness Woolley’s assertion that vehicles, in an**
22 **unmanaged charging scenario, would “add substantial on-peak load” (p. 19,**
23 **line 19) as evidenced by Figure GGW-3?**

24 **A45.** No. The data used in Figure GGW-3 in Witness Woolley’s testimony displays plug-
25 in times for Smart Charge Pilot enrollees. However, plug-in times are indicative of

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1 when a vehicle plugs-in to their charger, not when a vehicle begins charging.
2 Managed charging programs prefer customers plug in their vehicles when they
3 come home from work and the software utilized by the managed charging vendor
4 will schedule the charging session to deploy at the most optimal time (most likely
5 off-peak). Therefore, using plug-in data from a managed charging scenario is an
6 inaccurate counterfactual for unmanaged charging behavior and should not be used
7 as justification that unmanaged charging adds substantial on-peak load. An accurate
8 counterfactual to determine if unmanaged EVs add on-peak load would be to
9 analyze energy consumption patterns of unmanaged EVs. The Company has
10 performed this analysis and summarized the energy consumption of managed and
11 unmanaged EVs in Figure 4 below. This analysis indicates that unmanaged EVs
12 begin charging during off-peak hours, in alignment with their managed charging
13 counterparts, and thus do not add substantial on-peak load.

14

15 **Q46. Do you agree with Witness Woolley’s justification that the Pilot “often reduced**
16 **customer’s bills relative to unmanaged charging”?**

17 **A46.** No. The Company has analyzed unmanaged EV charging behaviors and determined
18 that unmanaged EVs are charging off-peak in alignment with their managed
19 charging counterparts as shown in Figure 4, in part due to the default time-of-use
20 residential rates. This alignment means the benefits of managed charging that have
21 been analyzed up to this point, including customer bill reductions, can be obtained
22 without the Pilot. Therefore, the Company has determined that further analysis on
23 the benefits of a managed charging program is necessary.

24

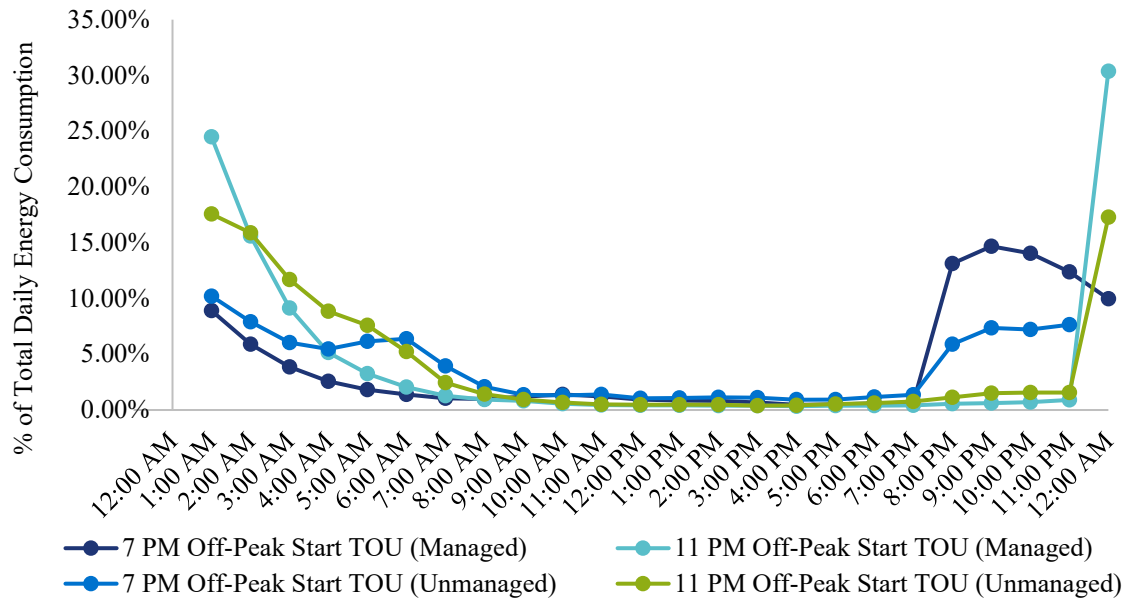
25

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1

Figure 4 Managed vs. Unmanaged Charging Performance

2



3

4 **Q47. Do you agree with MNSC Witness Woolley’s justification that the Pilot**
 5 **provides a positive financial impact to the Company of “about \$47.82 per**
 6 **participating vehicle”?**

7 **A47.** No. Witness Woolley indicated on page 19, lines 2-6 of his direct testimony, that
 8 there was a Net Incremental Revenue per Vehicle of \$47.82. However, it appears
 9 that Witness Woolley failed to include an EV management fee (per enrollee) and a
 10 platform fee(s) for DERMS solutions (Table 1, lines 9 and 12) that are included in
 11 the administrative costs as shown in his Exhibit CUB-23. These costs, when
 12 incorporated into the same data source, yield a negative Net Incremental Revenue
 13 Per Vehicle of \$104.55 as shown in Table 1.

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1

Table 1 Smart Charge Pilot Revenue & Costs

Item	Pilot Revenue & Costs	
1	Number of Enrollees	2,193
2	Fleet-level Capacity Costs in 2024	\$4,762
3	Distribution Rate for Smart Charge Enrollees (\$/kWh)	\$0.08907
4	Fleet-level Sales of Electricity in 2024	3,727,840
5	Distribution Revenue (Gross Margin) on Smart Charge Electricity Sales	\$332,038.71
6	Fleet-level Net Revenue	\$327,276.71
7	Revenue/Pilot EV	\$149.24
8	Total Annual Customer Incentive Costs (\$85 per Enrollee)	\$186,405.00
9	Total EV Management Fees (\$45.97 per Enrollee)	\$100,812.21
10	Annual Miscellaneous O&M Costs	\$24,000.00
11	Annual Miscellaneous Capital Costs	\$12,000.00
12	Platform Fee	\$233,335.85
13	Total Administrative Costs⁵	\$556,553.06
14	Cost/Pilot EV	\$253.79
15	Net Incremental Revenue	\$(229,276.35)
16	Net Incremental Revenue Per Vehicle	\$(104.55)

2

3 **Q48. Do you agree with MNSC Witness Woolley’s justification that the Pilot**
4 **“avoids costly new peak demand and associated system upgrades”?**

5 **A48.** Not necessarily. The Company believes that Smart Charge *might* “offer a powerful
6 opportunity to improve grid utilization and lower costs” (Woolley, p. 19, line 22).
7 However, further analysis is needed to quantify additional value streams such as
8 those discussed by Witness Woolley. The Company extended contracts with
9 WeaveGrid and ChargeScape until the end of 2026, with the goal of continuing to
10 analyze additional value streams. If the pilot were to be converted into a program
11 and scaled aggressively prior to quantifying additional value streams, as suggested

⁵ Total Administrative Costs = Total Annual Customer Incentive Costs + Total EV Management Fees + Annual Miscellaneous Capital Costs + Annual Miscellaneous O&M Costs + Platform Fee

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1 by Witness Woolley, the Company risks scaling a program whose costs do not
2 outweigh the benefits.

3

4 **Q49. What are the additional value streams that the Company plans to quantify**
5 **over the next pilot period?**

6 **A49.** Between now and the end of 2026, the Company is planning to quantify how EV
7 managed charging avoids or reduces the Company's need to invest in certain grid
8 infrastructure at the transformer, feeder, and/or substations levels. As an example,
9 the Company is planning to quantify how managed charging can affect the number
10 and size of EV chargers that can be safely accommodated on residential
11 transformers.

12

13 **Q50. Does the Company have any additional insights based on MNSC Witness**
14 **Woolley's recommendation?**

15 **A50.** Yes. If the Pilot were to be scaled into a program, cost increases will need to be
16 approved. Using the Pilot administrative costs submitted by the Company and the
17 32,044-vehicle assumption in Witness Wolley's Exhibit CUB-23, the annual
18 administrative cost to run the program would be approximately \$4.4M annually.

19

20 **Q51. What recommendation do you make to the Commission regarding the Smart**
21 **Charge pilot?**

22 **A51.** The Company recommends the Commission continue supporting Smart Charge as
23 a limited pilot between now and the end of 2026, while the additional value streams
24 discussed are analyzed. However, if the Commission agrees with Witness Woolley,

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1 the Company asks the Commission to approve \$4.4 million in annual O&M costs,
2 specifically earmarked for the Smart Charge program in this instant case.

3

4 DR Procurement

5 **Q52. Can you briefly explain the Company's efforts in working with aggregators to**
6 **procure DR?**

7 **A52.** Yes. The Commission approved a settlement in the Company's last IRP on July 26,
8 2023. In that settlement, the Company agreed to target 150 MWs of new DR
9 through a three (3) separate 3-year solicitations, with the first being for 25 MWs
10 beginning in the 2025/26 MISO Planning Year. The second solicitation would be
11 for an additional 25 MWs beginning in the 2026/27 MISO Planning Year and the
12 third would be for a 100 MW solicitation beginning in the 2027/2028 MISO
13 Planning Year.

14

15 **Q53. Has the Company met the requirements of the settlement agreement to date?**

16 **A53.** Yes. On June 26, 2024, the Company launched the first Request for Proposal (RFP)
17 for 25 MWs beginning with the 2025/26 MISO Planning Year and on April 10,
18 2025, the second RFP was launched for the 25 MWs beginning with the 2026/27
19 MISO Planning Year.

20

21 **Q54. Was the Company able to sign a contract with an aggregator to procure 25**
22 **MWs in the first solicitation?**

23 **A54.** No. As explained in Q82 of my direct testimony, the Company invited 14
24 aggregators to bid and received zero bids.

25

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1 **Q55. Was the Company able to contract with an aggregator to procure 25 MWs in**
2 **the second solicitation?**

3 **A55.** No. Much like the first solicitation, the Company invited 17 aggregators to bid and
4 received zero bids.

5
6 **Q56. Does MEIU Witness Albers make any recommendations on the Company's**
7 **DR procurement process?**

8 **A56.** Yes. The first recommendation Witness Albers makes begins with line 14 on page
9 6 of his direct testimony where he recommends that DTE Electric not require an
10 aggregator to provide the full 25 MW capacity. Witness Albers states on lines 18
11 and 19 of page 6 that "it may be easier for DTE to meet its obligation to procure
12 DR resources if it does not require a single aggregator to provide all 25 MW of
13 capacity." Witness Albers believes that multiple aggregators providing lesser
14 amounts of DR capacity will improve the results of the DR procurement RFP.

15
16 **Q57. How do you respond to MEIU Witness Albers' recommendation?**

17 **A57.** I would like to point out that Witness Albers uses the term "obligation" when
18 referring to procuring DR resources, which is incorrect. The Company's obligation
19 stemming from the 2022 DTE Electric IRP settlement in Case No. U-21193 was to
20 "target" DR MW through a competitive bidding process, which the Company has
21 done by issuing an RFP in each of the last two calendar years and will issue a third
22 RFP in 2026. As for allowing an aggregator to provide lesser amounts of DR
23 capacity, the Company believes that one aggregator should have been able to
24 procure 25 MWs. In the third solicitation, the Company expects to allow multiple

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1 aggregators to procure less than 100 MW of DR, in hopes of a successful DR
2 procurement.

3

4 **Q58. What other recommendations does MEIU Witness Albers make to improve**
5 **the DR solicitation?**

6 **A58.** MEIBC Witness Albers makes three additional recommendations to improve the
7 DR solicitation.

- 8 • Recommends that DTE Electric is the market participant rather than
9 aggregators for the load they bring (p. 7, lines 18-22, p. 8, lines 1-2);
- 10 • Recommends not limiting the bidders to aggregators who were invited to
11 bid by the Company (p.8, lines 4-19);
- 12 • Recommends a pay-for performance model (p.9, lines 1-8).

13

14 **Q59. Do you have any concerns with the additional recommendations made by**
15 **MEIU Witness Albers to improve the DR solicitation?**

16 **A59.** Yes. Witness Albers does not provide any arguments on why it would be beneficial
17 for DTE Electric to be the Midcontinent Independent System Operator (MISO)
18 Market Participant instead of the aggregator. He correctly points out that Table 1
19 of the DR procurement RFP (MEIU Exhibit 3.2, p. 7) outlines the roles and
20 responsibilities of the Company and aggregator, with most tasks belonging to the
21 aggregator with the Company acting as the reviewer (p. 7, lines 18-22). However,
22 DTE Electric disagrees with this recommendation and believes the Company's
23 approach is necessary to protect the Company and its customers from financial
24 harm. If DTE Electric were to be the Market Participant, all the risk for
25 underperformance, and any corresponding penalties, would fall to the Company

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1 along with increased responsibilities such as daily market offers, communications
2 between MISO and DR resources, DR testing requirements, MISO settlements and
3 meter data submissions.

4
5 In addition, MEIU Witness Albers assumes "...only those organizations explicitly
6 invited by DTE may submit a bid" (p. 8, lines 4-5). This is an incorrect assumption
7 that stems from page 20 of the RFP (MEIU Exhibit 3.2, p. 20) that says "Only those
8 organizations explicitly invited by the Company are eligible to bid on this RFP."
9 However, the paragraph goes on to read "If your organization is interested in
10 bidding but was not initially invited, you may contact the Buyer..." and provides
11 instructions on how non-invited bidders could submit a bid. In fact, this process
12 was used both in the first solicitation and the second solicitation as each solicitation
13 invited an additional bidder that was not on the original bidder list.

14
15 Witness Albers notes his concern that some of the bidders that were invited to bid
16 "are not aggregators and may be redundant" (p. 8, line 8). Witness Albers goes on
17 to note MEIBC is a trade association and not an aggregator, as is AEM-Alliance,
18 and that ecobee and Generac Power Systems (both invited to bid) are part of the
19 same organization. While Witness Albers is correct that MEIBC and AEM-
20 Alliance are trade associations, the Company is aware that neither of these groups
21 are aggregators themselves. The RFP was sent to these trade associations as a
22 courtesy and to make them aware of the RFP and share with aggregators in their
23 membership or in the broader DR industry. DTE Electric is not fully aware and
24 should not be expected to know of every DR aggregator that might have an interest
25 in participating. DTE Electric partnered with Guidehouse in good faith to identify

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1 aggregators that might be interested in bidding but also understood the reality that
2 not every single aggregator could realistically be invited to bid. As for ecobee and
3 Generac Power Systems being the same organization, ecobee reached out directly
4 to bid, despite being part of Generac, as ecobee was not on the original bidder list
5 but Generac was. The bidder list was also expanded for the second solicitation to
6 new aggregators in hopes of securing at least one response to the RFP.

7

8 Finally, Witness Albers proposes a pay-for-performance model, citing that
9 customers are more likely to participate when an event is called because there is an
10 incentive to do so. Because of this, Witness Albers believes aggregators would be
11 more likely to participate as opposed to offering 25 MW of capacity over three
12 years, regardless of customer performance (p. 9, lines 1-8). I do not disagree with
13 Witness Albers that customers would be more likely to participate if there was an
14 incentive to do so. However, it is stated in Table 1 of the RFP that the aggregator
15 is responsible for issuing incentives to customers. The Company is indifferent to
16 how aggregators choose to incentivize their customers as long as the customers
17 perform to the levels expected when called upon. It would not be beneficial to the
18 Company or its customers if the Company pays an aggregator to secure 25 MW
19 and in addition issued incentives to the customers that make up the aggregator's 25
20 MW. In this case, it would be more efficient for the Company to work with those
21 customers directly rather than going through an aggregator.

22

23 **Q60. Does MEIU Witness Albers make any further recommendations to the**
24 **Commission in regard to the Company's DR procurement efforts?**

Line
No.

1 **A60.** Yes, but they are not directly tied to the DR procurement efforts of the Company.
2 Beginning on page 10 of his direct testimony, he encourages the Company to
3 support lifting the ban on resources smaller than 1 MW participating in DR
4 aggregation. To support his argument and in an attempt to make DTE Electric
5 comfortable working with aggregators, Witness Albers states that “DTE does not
6 seem to be familiar with working with aggregators” (p. 10, lines 13-14) and then
7 goes on to describe programs around the country and their successes, such as
8 Arizona Public Service Company’s (APS) Cool Rewards VPP and a program called
9 ConnectedSolutions that exists in the Northeast. Both of these programs are
10 thermostat programs that are operated by EnergyHub.

11

12 **Q61. Does DTE Electric support lifting the ban on resources smaller than 1 MW**
13 **participating in DR aggregation?**

14 **A61.** Before addressing the aggregation ban on resources smaller than 1 MW, it should
15 be recognized that DTE Electric already works with EnergyHub on its opt-in
16 thermostat program, so the Company is already comfortable working with these
17 types of program implementers, many of whom also perform as “aggregators” in
18 other markets, as described above. DTE Electric’s Smart Savers program is a bring-
19 your-own-thermostat program that allows for temperature offsets in exchange for
20 participants receiving an annual incentive. This program is described further on
21 page 57 of my direct testimony. Along with EnergyHub, the Company has
22 experience working with program implementers such as ICF, Generac and
23 Weavegrid among others.

24

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1 Regarding lifting the ban on resources smaller than 1 MW, no, the Company does
2 not support this. As explained in Q80 of my direct testimony, the Company is
3 concerned with lifting the DR aggregation ban for residential customers.
4 Throughout page 47 of my direct testimony, I reference the fraud that occurred
5 when an aggregator was accused of signing up residential customers without their
6 knowledge and consent, the confusion that could arise with residential customers,
7 potential double counting of resources and ill-defined issue resolution channels for
8 residential customers. As indicated in the Order in Case No. U-21099, the
9 Commission had concern with residential customers participating in DR
10 aggregation as well, so the size minimum of 1 MW of enrolled load was
11 implemented.

12

13 Proposed DR O&M Disallowances

14 **Q62. Could you summarize AG Witness Coppola's position on the proposed**
15 **increase in spending on the Company's DR portfolio?**

16 **A62.** Yes. Beginning with line 16 on page 128 of his direct testimony, Witness Coppola
17 proposes to disallow the \$4,066,000 projection adjustment in demand response
18 O&M costs.

19

20 **Q63. What reasons does AG Witness Coppola give for his proposed disallowance?**

21 **A63.** Witness Coppola provides no evidence or support as to why he recommends
22 disallowing the increase in O&M other than it is "speculative at this time" (p. 129,
23 line 3).

24

25 **Q64. How does the Company respond to Witness Coppola's recommendation?**

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1 **A64.** The Company does not agree with Witness Coppola's recommendation. His
2 recommendation lacks evidence and merit and should not be considered by the
3 Commission. The \$4,066,000 that Witness Coppola recommends for disallowance
4 is associated with Smart Savers, Smart Charge, CoolCurrents, DR pilots and other
5 projects and are included in the projection adjustments in Company Witness
6 Foley's exhibit A-13, schedule C5.9. Support for this increase in spending is
7 supported throughout my direct testimony.

8

9 **Q65. Could you describe the projection adjustments that are included on Foley's**
10 **exhibit A-13, schedule C5.9?**

11 **A65.** Yes. Projection adjustments are forecasted increases in O&M spend over the
12 historic test period, which is calendar year 2023 in this instant case. For the Smart
13 Savers program, the Company is projecting to spend \$3.3 million annually
14 beginning in 2026 as indicated in lines 5 and 6 on page 58 of my direct testimony.
15 This is an increase of \$1.3 million over 2023 Smart Savers spend. The increase in
16 Smart Savers spend will support nearly 25,000 additional enrolled devices above
17 2023 levels and increase the program by an estimated 11 MW.

18

19 The Company is projecting an increase in spend associated with the Smart Charge
20 pilot of \$0.4 million above 2023 levels. This increase in spend is necessary to
21 expand the Smart Charge pilot to analyze different value streams on the distribution
22 system throughout 2026 to help determine whether Smart Charge should be
23 expanded to a cost-effective program.

24

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1 As described on page 52 of my direct testimony, the Company is increasing its
2 O&M within the CoolCurrents program by \$0.8 million through 2026. The increase
3 in O&M spend will allow the Company to fix 5,000 participating customers' 24v
4 lines.

5

6 To support the Company's additional DR programs and pilots, the dedicated DR
7 call center, DR procurement efforts, and general marketing and incentives
8 supporting program growth initiatives, the Company is projecting an increase of
9 \$1.5 million over 2023 levels.

10

11 **Q66. Can you summarize the \$4.0 million projecting adjustment in DR O&M that**
12 **the Company is requesting?**

13 **A66.** Yes. The \$4.0 million that the Company is requesting is a result of increased O&M
14 spending over 2023 levels for Smart Savers (+\$1.3 million), Smart Charge (+\$0.4
15 million), CoolCurrents (+\$0.8 million) and Pilots and other projects (+\$1.5 million)
16 and is shown in Witness Foley's exhibit A-13, C5.9.

17

18 Virtual Power Plants

19 **Q67. Could you summarize CEO Witness Kenworthy's position and**
20 **recommendation on Virtual Power Plants (VPPs)?**

21 **A67.** Yes. Witness Kenworthy's position is that VPPs would make "DTE's DERMS and
22 Grid Edge spend payoff: it organizes customer flexibility into dispatchable capacity
23 that reduces peaks, defers distribution infrastructure investment, and lowers system
24 costs." (p. 13, lines 7 - 10). He also states that VPPs can be stood up quickly, with
25 basic peak-shaving VPPs capable of beginning operations within about six months.

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1 Additionally, Witness Kenworthy proposes to defer approval of DERMS and
2 GridEdge Insights and New Technology until the Company files a VPP program.

3

4 **Q68. Does the Company agree with CEO Witness Kenworthy’s position that the**
5 **Commission tie the approval of DERMS and GridEdge and New Technology**
6 **funding to a VPP?**

7 **A68.** No, the Company does not agree. Company Witness Rademacher supports the
8 justification for DERMS and Grid Edge Insights and New Technology capital
9 expenditures in his direct and rebuttal testimonies regardless of the presence or plan
10 for a VPP implementation.

11

12 **Q69. Can you describe the Company’s current demand response programs?**

13 **A69.** Yes. The Company has a robust portfolio of DR programs and pilots. The DR
14 portfolio includes all but one of the distributed energy resources (DERs) Witness
15 Kenworthy lists as potential components of a VPP. Currently the DR portfolio
16 includes smart thermostats, water heating, interruptible air conditioning, EV
17 managed charging, and interruptible rate products. Additionally, the Company is in
18 initial development of a residential battery pilot that could be paired with rooftop
19 solar. While all these programs and pilots are in various stages of maturity, the
20 development and growth of these DERs has taken years and significant resources
21 to build.

22

23 Further, the Department of Energy defines a VPP as a “connected aggregation of
24 distributed energy resource technologies”⁶. Fundamentally, the Company operates

⁶ [VIRTUAL POWER PLANTS | Department of Energy](#)

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1 its available demand response resources and programs as a “connected” unit. It is
2 not evident what specifically a “VPP Tariff”, or a VPP generally, would improve
3 relative to the Company’s current DR portfolio.

4

5 **Q70. Do you have additional concerns with Witness Kenworthy’s recommendation**

6 **A70.** Yes, I have several.

7 • Basis for the proposal: The core of Witness Kenwothy’s expected benefits
8 are relative to utility scale batteries and gas peakers. (Page 14) This is the
9 wrong comparison and presumes that a “VPP” will displace these resources.
10 The Company’s integrated resource plan process is a far more appropriate
11 venue to weigh the value of demand response holistically, and to assess
12 whether a “VPP” is additive to the Company’s already robust demand
13 response portfolio.

14 • Benchmarks: Witness Kenworthy references VPP output in California as
15 evidence that they are an important tool, and says they “visibly reduced
16 CAISO net load at the net peak—precisely when capacity is most valuable”
17 (Page 14). While the Company does not question Witness Kenworthy’s
18 cited numbers, responding to capacity events and providing system peak
19 reductions is precisely the role played by DTE Electric’s existing demand
20 response portfolio.

21 • Timeline: While it remains unclear what specific gap Witness Kenworthy
22 is pointing towards given the Company’s demand response portfolio, to the
23 extent he is recommending new technologies, third party relationships,
24 customer interfaces, etc, there is simply no option to execute such work in
25 the timeline suggested. Moreover, without the appropriate time to analyze

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1 how the various technologies interact with each other and with the grid, the
2 Company is at risk of investing in technologies that provide lesser benefits
3 than costs. Lastly, to the extent Witness Kenworthy's comparable resource
4 is a gas peaker, six months is a materially insufficient time to weigh such a
5 tradeoff.

6

7 **Q71. What is the Company's recommendation regarding CEO Witness**
8 **Kenworthy's VPP proposal?**

9 **A71.** The Company recommends that the Commission reject Witness Kenworthy's VPP
10 proposal for the reasons laid out in my rebuttal testimony.

11

12 **Q72. Does this conclude your testimony?**

13 **A72.** Yes, it does.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of)
DTE ELECTRIC COMPANY)
for authority to increase its rates, amend)
its rate schedules and rules governing the)
distribution and supply of electric energy, and)
for miscellaneous accounting authority.)

Case No. U-21860

REBUTTAL TESTIMONY

OF

JASON E. SPARKS

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF JASON E. SPARKS

1 **Q1. Please state your full name, business address and by whom you are employed?**

2 A1. My name is Jason E. Sparks. My business address is One Energy Plaza, Detroit,
3 Michigan 48226. I am employed by DTE Energy Corporate Services, LLC.

4

5 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
6 **Company (DTE Electric or Company)?**

7 A2. Yes.

8

9 **Purpose of Testimony**

10 **Q3. What is the purpose of your rebuttal testimony?**

11 A3. The purpose of my testimony is to rebut the arguments made by:

12 • Attorney General (AG)

13 ○ AG Witness Coppola's omission of the 3-year average of direct
14 expense in the uncollectible expense calculations

15 • Detroit Area Advocacy Organization (DAAO)

16 ○ DAAO Witness Schott's statements on DTE's senior restores &
17 winter protection activities

18 ○ DAAO Witness Schott's statements on unregulated programs and
19 disconnects

20 ○ DAAO Witness Schott's statements on late fees and reporting
21 variances

22 ○ DAAO Witness Jacob's statements on PIPP implementation
23 recommendations

24 • Ecology Center, the Environmental Law & Policy Center, the Union of
25 Concerned Scientists, and Vote Solar (Collectively CEO)

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- 1 ○ CEO Witness Tan's position that DTE's disconnection policies are
- 2 not uniformly applied across our service territory and is the cause of
- 3 disparities within census tracts
- 4 • Citizens Utility Board of Michigan (CUB)
- 5 ○ CUB Witness Bunch's recommendation that DTE should be
- 6 directed to investigate an increase in disconnections and explain
- 7 why customers remain disconnected at the end of each month
- 8 ○ CUB Witness Bunch's position on DTE's cash only policy

9

10 **Q4. Are you sponsoring any rebuttal exhibits?**

11 A4. Yes. I am sponsoring the following rebuttal exhibit:

12	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
13	A-41	FF1	Comparison of DTE UCX Projection vs AG UCX Projection

14

15 **Uncollectible Expense**

16 **Q5. Do you agree with AG Witness Coppola's revised calculation of Uncollectible**

17 **Expense and the disallowance of \$1.6 million?**

18 A5. While DTE Electric agrees with the general methodology employed by AG Witness

19 Coppola in evaluating uncollectible expense, the Company notes an omission in his

20 analysis: the exclusion of the three-year average of direct expense. The inclusion

21 of the three-year average of direct expense is consistent with the methodology

22 approved by the Commission in its final order in DTE Electric's prior rate case (U-

23 21534). Exhibit A-41 Schedule FF1 depicts the adjustment, adding back \$1.2

24 million to the uncollectible expense calculation. Additionally, DTE Electric does

25 not object to Staff Witness Braunschweig's recommendation, on page 10, line 4-8,

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1 of her testimony, to allocate Low Income Payment Stability Plan (PSP)
2 Amortization Expenses through the COSS calculations, removing \$1.0 million
3 from the uncollectible expense calculation. The net of the two adjustments results
4 in \$46.6 million in uncollectible expense and an upward adjustment of \$0.2 million
5 from AG Witness Coppola's projection.

6

7 **Disconnects**

8 **Q6. Do you agree with CEO Witness Tan's position that DTE's disconnection**
9 **policies are not uniformly applied across its service territory and is the cause**
10 **of disparities within census tracts as outlined on page 3 lines 10-12?**

11 A6. No. DTE Energy maintains that its disconnection policies are applied uniformly
12 across its service territory, in accordance with Michigan Public Service
13 Commission (MPSC) regulations and approved tariff provisions. Disconnection
14 decisions are based on account status and payment history, not geographic location,
15 race, or income level. While DTE continuously reviews its policies to ensure
16 fairness and transparency, there is no evidence to suggest systemic disparities in
17 disconnection practices based on demographic or regional factors.

18

19 **Q7. What is the Company's position on Witness Tan's (page 3) and Witness**
20 **Schott's (page 106) recommendation that the Company be required to track**
21 **non-pay disconnects by census tract?**

22 A7. While the Company appreciates the intent behind the recommendation to collect,
23 aggregate and report disconnect data at the census tract level, DTE does not believe
24 this approach is practical nor necessary to achieve meaningful insights into
25 customer disconnection trends. This methodology raises the following concerns:

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1 Data privacy – The level of detail for census tracts is more granular than that of zip
2 code. By narrowing the number of households in each data set, it may be possible
3 to match customers to disconnect information.

4 System compatibility – The Company’s billing system is not configured to
5 accommodate disconnect data at the census tract level and would require the
6 Company to develop new programming and processes for defining and collecting
7 customer data for census tracts.

8

9 **Q8. Do you agree with CUB Witness Bunch’s recommendation on page 14 line 19-**
10 **21 that DTE should be directed to investigate and explain an increase in**
11 **customers who remain disconnected at the end of each month?**

12 A8. DTE Electric respectfully disagrees with CUB Witness Bunch’s recommendation
13 on page 14, lines 19–21 of his testimony, suggesting that the Company be directed
14 to investigate and explain the increase in customers who remain disconnected at the
15 end of each month.

16

17 The disconnect data analysis on page 8-11 referenced in the U-20757 report
18 pertains to premises, not individual customers. This distinction is important. A
19 disconnected premise may reflect a range of circumstances, such as vacancy,
20 seasonal inactivity, or a customer who has relocated. As such, drawing conclusions
21 about customer behavior or hardship from this data risks oversimplifying a complex
22 picture.

23

24 Furthermore, undertaking comprehensive analysis to identify and engage with
25 customers who have not reactivated service would be a substantial and resource-

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1 intensive effort. It would require first distinguishing which disconnected premises
2 correspond to actual customers, initiating outreach, and relying on voluntary
3 responses. Given the limitations of the data and the uncertainty of meaningful
4 engagement, the value of such an investigation is questionable.

5

6 DTE remains committed to transparency and continues to provide detailed
7 reporting under U-20757. However, any additional directives should be grounded
8 in a clear understanding of the data's scope and limitations and balanced against
9 the practical feasibility and potential impact of the proposed analysis.

10

11 **Q9. Do you agree with DAAO Witness Schott's comments on page 45 lines 3-11**
12 **regarding DTE's efforts to restore seniors in preparation for the winter**
13 **heating season?**

14 A9. While Schott's claim suggests that DTE failed to restore service to seniors, that
15 characterization overlooks both the complexity of reconnection efforts and the
16 proactive measures the Company undertook. DTE's Senior Winter Protection
17 yearly campaign is designed to identify and assist vulnerable seniors before the
18 onset of winter. Reaching out to 1,500 seniors disconnected after the heating season
19 demonstrates a strong commitment to public safety and customer care.

20

21 DTE may not always have immediate visibility into the circumstances of seniors
22 following a disconnection, but DTE proactively conducts outreach to ensure they
23 have the opportunity to restore service if needed. When a senior does not respond
24 to initial contact attempts, our outreach escalates to include a site visit. Through
25 these efforts, we often learn that some individuals have either relocated—such as

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1 moving in with a relative—or, in some cases, have passed away, and therefore no
2 longer require service restoration. Restoration of service is not automatic and
3 requires customer engagement, eligibility verification, and in some cases,
4 resolution of safety or billing issues. Despite these constraints, DTE successfully
5 restored service to 357 seniors during DTE’s 2024-2025 Senior Winter Protection
6 campaign, representing hundreds of households now protected during the heating
7 season.

8

9 **Low Income Programs**

10 **Q10. Do you agree with the recommendations pertaining to DTE’s Percentage of**
11 **Income Payment Plan (PIPP), also known as the Payment Stability Plan (PSP),**
12 **by DAAO Witnesses Jacob on page 55 lines 3-17, Schott on page 49 lines 1-4,**
13 **and Watts on page 32 lines 4-10?**

14 A10. DTE acknowledges the intent behind DAAO Witness Jacob’s, Schott’s, and Watts’
15 recommendations regarding the Percentage of Income Payment Plan (PIPP), known
16 as the Payment Stability Plan (PSP). The Company recognizes that income-based
17 payment models can offer meaningful support to low-income customers by
18 promoting affordability and stability.

19

20 However, DTE is currently awaiting the outcome of the Commission’s review on
21 this issue, which is informed by the collaborative work of the Energy Affordability
22 and Accessibility Collaborative (EAAC). The EAAC has been instrumental in
23 evaluating the feasibility, design, and implementation considerations of a statewide
24 PIPP framework. DTE believes it is important to allow that process to conclude so

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1 that any future direction is aligned with broader policy objectives and stakeholder
2 input.

3
4 In the meantime, DTE remains committed to supporting customers through existing
5 affordability programs and continues to engage actively in the EAAC process to
6 help shape equitable and sustainable solutions.

7

8 **Late Fees**

9 **Q11. Can you clarify the variance between the responses provided in discovery**
10 **requests DAAODE-7.3a and DAAODE-4.5 regarding late fees, as referenced**
11 **in DAAO Witness Schott's testimony on pages 32–33, lines 12–15?**

12 A11. Yes. The difference in responses to DAAODE-4.5 and DAAODE-7.3a stems from
13 the distinct methodologies and objectives behind each data set.

- 14 • **DAAODE-4.5** was generated for residential customer-level data with
15 filters that showed only paid or written off amounts.
- 16 • **DAAODE-7.3a** includes any late fees assessed to any and all customers,
17 regardless of rate schedule, as per the general ledger account where late
18 fees are recorded.

19 The variance between the two responses is therefore a result of the differing scopes
20 and intents of the underlying discovery requests, where one addresses operational
21 customer data and the other financial accounting records.

22

23 **Cash Only Policy**

24 **Q12. Do you agree with CUB Witness Bunch's position regarding DTE's cash only**
25 **policy on pages 39-48?**

Line
No.

1 A12. DTE respectfully disagrees with Witness Bunch’s assertion that there is no basis
2 for the Company’s cash-only payment requirement following a returned payment.
3 Recognizing the challenges posed by customer arrearages, the implementation of a
4 cash-only policy is a targeted operational safeguard designed to reduce repeated
5 payment failures and protect both customers and the Company from compounding
6 financial risk.
7
8 Customers whose payments are declined by financial institutions have already
9 demonstrated a breakdown in payment reliability. While late fees and returned
10 payment fees may serve as deterrents, they do not prevent future failed transactions.
11 Requiring a cash payment—defined broadly to include verified funds such as
12 money orders or cashier’s checks—ensures that the next payment is valid and
13 immediately credited, avoiding further arrearage accumulation and unnecessary
14 billing cycles.
15
16 This policy also reduces administrative costs associated with processing failed
17 payments and supports accurate financial reporting. It is not intended to penalize
18 customers, but rather to reinforce payment integrity after a failed transaction.
19 DTE remains committed to offering multiple payment options and supporting
20 customers through affordability programs. The cash-only requirement is applied
21 selectively and only after a payment has been returned, reflecting a measured
22 approach to risk management—not a blanket restriction.

Line
No.

1 **Q13. Do you agree with DAAO Witness Schott's assertion, as stated on pages 45–47**
2 **of his testimony, that DTE has not made any substantive changes to its cash**
3 **only policy?**

4 A13. No, the Company has taken proactive steps to revise its payment policies in direct
5 response to both customer feedback and internal evaluations. These changes reflect
6 DTE's commitment to continuous improvement and stakeholder engagement. The
7 latest revision of the policy includes the addition of a 3-day grace period before a
8 payment method restriction is applied. If customers make the follow up payment
9 within three days, they avoid the payment method restriction. This policy applies
10 to customers who have only had one returned payment within the last 12 months.

11

12 **Q14. Does this conclude your rebuttal testimony?**

13 A14. 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

REBUTTAL TESTIMONY

OF

MICHAEL S. COOPER

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF MICHAEL S. COOPER

Line
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1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed?**

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

6
7 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
8 **Company (DTE Electric or Company)?**

9 A2. Yes.
10

11 **Purpose of Testimony**

12 **Q3. What is the purpose of your rebuttal testimony?**

13 A3. My testimony will rebut the testimony of Michigan Public Service Commission
14 Staff (Staff) Witness Rueckert and Attorney General (AG) Witness Coppola.
15 Specifically, I will rebut:

- 16 • Staff Witness Rueckert's and AG Witness Coppola's proposed adjustments
- 17 to the Company's projected New Hire VEBA expense,
- 18 • Staff Witness Rueckert's proposed adjustment to Other Benefit expense,
- 19 and,
- 20 • AG Witness Coppola's proposed adjustment to Active Healthcare expense.

21 The absence of a discussion of other matters in my testimony should not be
22 regarded as an indication that I agree with all other aspects of the Staff's and
23 intervenors' testimony. The narrow focus of my testimony is instead a consequence
24 of a focus on priority issues in recognition of the available resources.

Line
No.

1 **Q4. Are you sponsoring any exhibits in this proceeding?**

2 A4. Yes. I am sponsoring, in whole or in part, the following exhibits:

3	Exhibit	Schedule	Description
4	A-36	AA1	Normalized 2024 Employee Benefits Expense
5	A-36	AA2	VEBA 2024 Excess True Ups
6	A-36	AA3	VEBA Forfeitures: 2016 to 2023
7	A-36	AA4	Adjusted VEBA Escalation Rates
8	A-36	AA5	Adjusted Staff VEBA Expense
9	A-36	AA6	Adjusted Staff Other Employee Benefits Expense
10	A-36	AA7	AG Response to DEAG-2.1

11

12 **Q5. Were these exhibits prepared by you or under your direction?**

13 A5. Yes, they were.

14

15 **Normalized 2024 Employee Benefits Expense**

16 **Q6. Has the Company developed a normalized level of 2024 Employee Benefits**
17 **Expense?**

18 A6. Yes, exhibit A-36, Schedule AA1 reflects a normalized level of 2024 Employee
19 Benefits, which is comparable to Exhibit A-13, Schedule C5.11, page 2. This
20 schedule starts with actual 2024 Employee Benefits expense and makes known and
21 measurable changes to develop the 2024 normalized Employee Benefits expense.

22

23 **Q7. What are the known and measurable changes related to Temporary Items**
24 **reflected in columns (c)?**

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1 A7. Similar to Exhibit A-13, Schedule C5.11, this Exhibit A-36, Schedule AA1
2 includes adjustments for Temporary Items, in column (c) that relate to temporary
3 cost reductions implemented in 2023 related to the Company's Wellness Plan (line
4 17) and General Benefits (line 21), as described in my Direct Testimony on pages
5 26 and 27, respectively. The basis for the adjustment to 2024 expense is identical
6 to the adjustment made to the Company's 2023 Employee Benefits expense. Also
7 included as a Temporary Item is the impact of out of period rebates, which reduced
8 medical expense by \$0.468 million, and is included in line 8. Further, the
9 Temporary Item for Medical expense also includes the impact of the Company
10 accruing 27 pay periods in 2024, rather than the typical 26 pay periods. Because
11 employee contributions for Medical, Dental, Vision and Life Insurance are
12 recognized when accrued, the Company recognized non-recurring employee
13 contributions in 2024 for these benefits. The excess for medical was \$0.514
14 million, which combined with the out of period rebates results in a total medical
15 Temporary Item of \$0.982 million. The amounts under Temporary Items for
16 Dental, Vision and Life Insurance are related to these excess employee
17 contributions.

18

19 **Q8. What are the Normalization Adjustments reflected in column (d)?**

20 A8. The Normalization Adjustments in column (d) relate to New Hire VEBA,
21 Employee Savings Plan, Medical Expense, Accrued Vacation, Supplemental
22 Savings Plan and Deferred Compensation. The Normalization Adjustments for
23 New Hire VEBA will be discussed in detail below and for the Employee Savings
24 Plan is addressed by Company Witness Fix. The normalization of medical expense
25 reflects the adjustment to the Company's self-insured medical expense similar to

Line
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1 the normalization adjustment discussed in my Direct Testimony on pages 14
2 through 21. The Normalization Adjustment for Accrued Vacation expense, on line
3 13, is based on an updated five-year average of Accrued Vacation expense,
4 consistent with long-standing Commission practice. The Normalization
5 Adjustments for Supplemental Savings Plan and Deferred Compensation, as
6 reflected on line 15 and 16, respectively, relates to adjusting the actual 2024
7 expense to the Expected Return on Assets on pension assets for 2024, as described
8 in Company Witness Fix's Direct Testimony on pages 13 through 15.

9

10 **Q9. What are the adjustments related to Lag Hiring included in column (e)?**

11 A9. In early 2024, the Company implemented the Voluntary Separation Incentive Plan
12 (VSIP) that reduced the Company's workforce. In connection with the workforce
13 reduction, the Company anticipated hiring new employees that were needed in
14 certain strategic areas and replacing employees in areas where employee
15 participation was greater than planned. As a result, at year end 2024 the Company
16 had a number of open positions. The direct labor expense related to those open
17 positions was \$9.361 million, as provided to me by Company Witness Uzenski.
18 The adjustment in column (e) represents the Employee Benefits expense related to
19 those direct labor costs, based on the Company's Employee Benefits overhead rate
20 of 27.4%.

21

22 **New Hire VEBA Expense**

23 **Q10. What adjustment did Staff Witness Rueckert propose to the Company's New**
24 **Hire VEBA (VEBA) Expense?**

Line
No.

1 A10. Staff Witness Rueckert developed the Company's VEBA expense for the projected
2 test year based on the escalation of the Company's actual 2024 VEBA costs of
3 \$10.313 million by the five-year average of historical annual increases of 3.5% to
4 develop projected VEBA costs of \$11.043 million. This projected VEBA cost was
5 reduced for the proportion of VEBA costs charged to expense in 2024 of 54.3% to
6 produce a projected VEBA expense of \$6.002 million (Rueckert Amended Direct,
7 page 6, lines 1 through 17 and Exhibit S-24.3)

8

9 **Q11. Do you agree with Staff Witness Rueckert's adjustment for VEBA expense?**

10 A11. No. Staff Witness Rueckert's approach, based on 2024 VEBA costs as escalated by
11 3.5% annually, is flawed because it relies on unadjusted VEBA costs as a starting
12 point, without any normalization for the impact of excess true ups recognized in
13 2024 and the impact of lag hiring on VEBA expense. He also uses a historical
14 average of the Company's actual percentage changes in the Company's VEBA
15 costs, rather than the actual number of VEBA participants and projected increases
16 in participants.

17

18 **Q12. What adjustment to VEBA expense did AG Witness Coppola propose?**

19 A12. AG Witness Coppola developed the Company's VEBA expense for the projected
20 test year based on the escalation of the Company's actual 2024 VEBA expense of
21 \$5.605 and escalated by the compound annual growth rate in VEBA costs between
22 the years 2020 and 2024 of 1.5%, resulting in a projected VEBA expense of \$5.773
23 million. AG Witness Coppola adjusted this amount for the projected increase in
24 employees of 1.7% per year to produce a projected VEBA expense of \$5.969
25 million (Coppola Direct, page 137, lines 3 through 11, Exhibit AG-56).

Line
No.

1 **Q13. What is AG Witness Coppola's basis for his proposal?**

2 A13. AG Witness Coppola claims that his use of the Company's 2024 actual VEBA
3 expense eliminates the issue of the excessive true ups in 2023 and that his calculated
4 compound annual growth rate for the years 2020 through 2024 is representative of
5 "normal historical growth rate" (Coppola Direct, page 136, lines 14 through 16,
6 page 137, lines 4 through 6).

7
8 **Q14. Do you agree with AG Witness Coppola's proposed adjustment to the**
9 **Company's projected VEBA expense?**

10 A14. No. Similar to Staff Witness Rueckert, AG Witness Coppola fails to adjust the
11 2024 actual VEBA expense for excess true ups recognized in 2024 and the impact
12 of lag hiring on VEBA expense. Moreover, his use of the compound annual growth
13 rate in the Company's VEBA costs between the years 2020 and 2024 represents too
14 short of a period, because it excludes the increase in the Company's 2019 VEBA
15 costs. Moreover, the use of the compound growth rate is inconsistent with
16 traditional Commission practice of using the average of the annual percent change
17 in costs, which would produce an annual escalation rate of 2.3%.

18
19 **Q15. Is it proper to use unadjusted VEBA costs as a basis for determining the**
20 **Company's projected VEBA costs?**

21 A15. No. While Staff Witness Rueckert is silent on the issue of the normalization of
22 excess true ups as I discussed on pages 10 and 11 of my Direct Testimony, AG
23 Witness Coppola claims that the use of 2024 obviates the need for any such
24 normalization, as discussed above.

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1 In 2024, the Company also recognized an unusually high level of true ups related
2 to its VEBA expense. In response to the Attorney General's discovery request, the
3 Company provided a schedule of the known and measurable changes for 2024 as
4 an update to the known and measurable changes reflected in Exhibit A-13, Schedule
5 C5.11 page 2 related to 2023. An updated version of that response, which is
6 reflected on Exhibit A-36, Schedule AA1, shows a VEBA normalization
7 adjustment on line 4, column (d) of \$1.247 million related to excess true ups. The
8 basis for this normalization adjustment is reflected in Exhibit A-36, Schedule AA2,
9 which shows the five-year average of actual true ups recognized for the years 2017
10 through 2021 of \$0.439 million compared to true up recognized in 2024 of \$2.734
11 million. This produces an excess true up in 2024 of \$2.295 million, which after
12 adjustment for the portion expensed, results in a normalization adjustment of
13 \$1.247 million.

14

15 **Q16. Why do you propose using the five-year average of VEBA true ups for the**
16 **years 2017 through 2021?**

17 A16. I use a five-year average of VEBA true ups for the years 2017 through 2021 because
18 the true ups in 2022 and 2023 were also unusually high. To-wit, true ups in 2022
19 and 2023 were \$2.136 million and \$2.920 million, respectively.

20

21 **Q17. What is the cause of unusually high VEBA true ups recognized in the years**
22 **2022 through 2024?**

23 A17. Because it is impossible to accurately project VEBA forfeitures due to employee
24 departures, which are the largest contributors to true ups, the Company generally
25 accrues VEBA costs exclusive of any projected forfeitures. Company contributions

Line
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1 to employee VEBA accounts vest after ten years. Accordingly, employees who
2 depart the Company prior to ten years forfeit their accumulated VEBA balances.
3 Because employees can have their VEBA balances restored if they return to the
4 Company within 12 months, the Company doesn't recognize the forfeitures until
5 the year after the employee leaves the Company. This results in VEBA cost true
6 ups arising that can vary significantly among years.

7

8 **Q18. What were the amount of VEBA forfeitures recognized in the years 2016**
9 **through 2023?**

10 A18. The VEBA forfeitures for the years 2016 through 2023 are reflected in Exhibit A-
11 36, Schedule AA3. The Company's VEBA funding, which is determined based on
12 actual earned employee VEBA contributions and forfeitures, isn't finalized until
13 late in the subsequent year. Therefore, the actual forfeitures from the prior year
14 form the basis for the true up in the subsequent year. That is, forfeitures for the
15 years 2016 through 2023 are the basis for the true ups recognized during the years
16 2017 through 2024.

17 For the years 2016 through 2019, annual forfeitures averaged less than \$0.5 million,
18 as shown on line 11. In 2020, as a result of the COVID-19 pandemic, when
19 employee turnover fell dramatically, forfeitures were less than \$0.1 million, as
20 shown on line 12. As the economy recovered from the pandemic, employee
21 turnover increased, which led to increased forfeitures. As a result, the average
22 annual forfeitures in the years 2022 and 2023 grew to \$2.614 million, as shown on
23 line 13, which reflects a continuing transition from the COVID-19 pandemic that
24 isn't representative of a normal level of forfeitures.

Line
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1 **Q19. Did the Company normalize its VEBA costs for the impact of excess forfeitures**
2 **in its most recent rate case?**

3 A19. Yes. In the Company's filing in Case No. U-21534, the Company made a
4 normalization adjustment that was based on the five-year average of true ups for
5 the years 2017-2021 compared to the actual 2022 true up, which increased the
6 Company's VEBA expense by \$1.027 million. No party objected to the Company's
7 proposal and therefore, the normalization adjustment was included in the revenue
8 requirement ordered by the Commission in that case.

9

10 **Q20. Has the Commission recognized the impact of the COVID-19 pandemic on**
11 **other Employee Benefits Expense?**

12 A20. Yes. In Case No. U-21534, the Commission recognized that the percentage
13 changes in the Company's Employee Savings Plan expense should exclude the
14 years 2021 and 2022 from the historical average used in projecting that expense
15 (Order, January 23, 2025, p. 250). Because the ongoing transition out of the
16 pandemic and the lag in forfeitures being recognized, the Commission's conclusion
17 regarding Employee Savings Plan is equally applicable here.

18

19 **Q21. What do you conclude from this analysis of VEBA true ups?**

20 A21. Because the Company experienced higher than normal forfeitures in 2023, which
21 resulted in excessive true ups in 2024, the excess true up recognized in 2024 should
22 be eliminated from the starting point of both Staff Witness Rueckert's proposal and
23 AG Witness Coppola's proposal.

Line
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1 **Q22. Why is Staff Witness Rueckert's and AG Witness Coppola's escalation rates**
2 **improper?**

3 A22. Both Staff Witness Rueckert and AG Witness Coppola used historical increases in
4 the Company's VEBA costs without adjusting for the excess true ups and the
5 impact in 2024 of lag hiring on VEBA costs.
6 Staff Witness Rueckert uses the years 2019 through 2024, which produces a five-
7 year average annual percentage change of 3.48%. Whereas AG Witness Coppola
8 seems to have developed a compound annual growth rate based on the VEBA costs
9 for the years 2020 through 2024 of 1.5%. AG Witness Coppola adjusts this
10 escalation rate for the projected annual growth in employees, which he calculated
11 to by 1.7%. This results in a total annual escalation by AG Witness Coppola of
12 effectively 3.2%.

13

14 **Q23. Do you agree with the escalation rates proposed by Staff Witness Rueckert or**
15 **AG Witness Coppola?**

16 A23. No. While Staff Witness Rueckert uses a five-year average of annual changes in
17 the Company's VEBA costs, his calculation fails to adjust the Company's recorded
18 VEBA costs for the impact of the extremely high excess true ups in 2022, 2023,
19 and 2024.

20

21 **Q24. Have you recalculated Staff Witness Rueckert's annual average escalation**
22 **that reflects the impact of the excess true ups?**

23 A24. Yes. Exhibit A-36, Schedule AA4, reflects the Company's recorded VEBA costs
24 for each of the years 2019 through 2024 and adjusts those costs for the excess true
25 ups in 2022, 2023 and 2024. The excess true up for 2022 was \$1.697 million as

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1 used in the Company's filing in Case No. U-21534. The excess true up for 2023 is
2 based on the Company's filing in this case, which reduced VEBA costs by \$2.481
3 million. The 2024 excess true up of \$2.295 million is from Exhibit A-36, Schedule
4 AA2, line 8. The Company's adjusted VEBA costs have increased by an average of
5 7.82% over five years, as shown in line 8 of Exhibit A-36, Schedule AA4. This
6 figure accounts for excess true ups and the effect of lag hiring on VEBA. The
7 compound average growth rate for the five-year period is 7.55%, in contrast to the
8 1.5% compound average growth rate computed by AG Witness Coppola.

9

10 **Q25. Have you recomputed Staff Witness Rueckert's projected VEBA expense**
11 **based on the 7.82% average annual escalation rate?**

12 A25. Yes. Exhibit A-36, Schedule AA5 reflects a recalculation of Staff Witness
13 Rueckert's projected VEBA expense based on the normalized 2024 starting point
14 and the 7.82% annual escalation. The VEBA costs are projected to be \$14.996
15 million for the projected test year. After adjusting for the proportion of costs to be
16 expensed, the projected VEBA expense is \$8.150 million, or an increase to the Staff
17 Witness Rueckert's projection of \$2.148 million. It is worth noting that this
18 adjusted VEBA expense is comparable to the Company's projected VEBA expense
19 of \$7.777 million, as reflected on Exhibit A-13, Schedule C5.11, which supports
20 the reasonableness of the Company's original projection.

21

22 **Other Benefits Expense**

23 **Q26. What is Staff Witness Rueckert's proposal for Other Benefits expense?**

24 A26. Staff Witness Rueckert uses the novel approach of grouping all other benefits
25 expense categories, as detailed in Exhibit S-24.3, lines 13 through 16, and

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1 escalating the total of those expense categories by the five-year average of annual
2 percent changes in the costs. Specifically, Staff Witness Rueckert starts with the
3 sum of the Company's actual 2024 Other Benefits costs of \$19.831 million and
4 escalates that cost by 4.40% per year to generate projected Other Benefits costs of
5 \$21.615 million, which after adjustment for the proportion of the costs expensed
6 results in Other Benefits expense of \$12.222 million.

7

8 **Q27. Do you agree with Staff Witness Rueckert's proposed Other Benefits expense**
9 **projection?**

10 A27. No. First, Staff Witness Rueckert has amalgamated into one projection a variety of
11 remarkably dissimilar benefits cost categories. Second, Staff Witness Rueckert has
12 failed to adjust the 2024 benefits costs for any of the known and measurable
13 changes, as reflected in Exhibit A-36, Schedule AA1.

14

15 **Q28. Do you have an alternative to Staff Witness Rueckert's Other Benefits expense**
16 **projection?**

17 A28. While I believe the Other Benefits expense projection included in Exhibit A-13,
18 Schedule C5.11 are the best projection of Other Benefits expense, if the
19 Commission is persuaded that a projection based on 2024 actuals expenses is
20 preferable, it should update the Staff Witness Rueckert's projections for the effect
21 of the known and measurable changes identified on Exhibit A-36, Schedule AA6
22 and individually develop projections of future Other Benefits expense.
23 Specifically, Exhibit A-36, Schedule AA6, uses the same Other Benefits categories
24 reflected on Exhibit S-24.4 and makes the necessary known and measurable
25 adjustments to develop a normalized 2024 Other Benefits expense of \$13.712

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1 million. This normalized amount is adjusted for the Company's escalations based
2 on the individual expense. That is, Accrued Vacation and Life Insurance are
3 escalated at the 3.0% labor escalation, Wellness and Affordable Care Act expense
4 are escalated at the Company's Active Healthcare projected escalations and all
5 other items are escalated by the Company's projected Consumer Price Index
6 increases.

7

8 In addition to the escalations, Exhibit A-36, Schedule AA6 also reflects certain
9 specific projections in column (j). The projected Supplemental Severance expense
10 is based on estimates provided by Aon, the Company's actuaries. Also,
11 Supplemental Savings Plan and Deferred Compensation expense projections are
12 based on the Expected Return on Pension assets.

13

14 This results in a projected Other Benefits expense of \$14.773 million compared to
15 Staff Witness Rueckert's projected Other Benefits expense of \$12.222 million, or
16 an increase of \$2.551 million. This adjusted Other Benefits expense is comparable
17 to the Company's projected Other Benefits expense of \$15.250 million, as reflected
18 on Exhibit A-13, Schedule C5.11, which supports the reasonableness of the
19 Company's original projection.

20

21 **Active Healthcare Expense**

22 **Q29. What adjustment did AG Witness Coppola propose to Active Healthcare?**

23 A29. AG Witness Coppola proposes that the Company's Active Healthcare expense be
24 projected based on the Company's actual 2024 expense of \$45.437 million, which
25 is the sum of the Company's Medical, Dental and Vision cost categories, without

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1 adjustment for the Company's self-insured medical normalization adjustment. AG
2 Witness Coppola escalates the 2024 actual Active Healthcare expense by projected
3 increases in the Consumer Price Index (CPI) of 2.8% and 2.4% for 2025 and 2026,
4 respectively. Similar to VEBA, he further increases the Active Healthcare expense
5 for the projected increase in employees, which he calculated as 1.7% per year. This
6 results in a projected Active Healthcare expense of \$49.456 million, compared to
7 the Company's filed projection reflected on Exhibit A-13, Schedule C5.11 of
8 \$49.969 million, or a reduction of \$0.513 million. The total escalation of Active
9 Healthcare expense proposed by AG Witness Coppola is \$4.019 million, which
10 represents an annual average increase of 4.4% for the two years.

11

12 **Q30. Do you agree with AG Witness Coppola's projected Active Healthcare**
13 **expense?**

14 A30. While I disagree with the use of the CPI to escalate Active Healthcare expense due
15 to the long historical record of medical related costs increasing faster than overall
16 inflation, the overall escalation of 4.4% is comparable with the Company's filed
17 projections. Accordingly, I have no specific corrections to AG Witness Coppola's
18 projected Active Healthcare expense.

19

20 **Q31. Did AG Witness Coppola address the Company's proposed self-insured**
21 **medical costs adjustment?**

22 A31. Yes. AG Witness Coppola avers that the Company's self-insured medical cost
23 normalization adjustment is the same as the net normalization of Active Healthcare
24 expense that the Company has proposed in its two most recent rate cases (Case Nos.

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1 U-21297 and U-21534). Based apparently on that conclusion, he rejects the
2 Company's self-insured medical cost normalization adjustment.

3

4 **Q32. Is the self-insured medical cost adjustment the same as the constant dollar**
5 **Active Healthcare adjustment?**

6 A32. No. They are completely unrelated. The constant dollar adjustment looked back
7 on five years of the Company's actual Active Healthcare costs and adjusted each
8 of those years' costs to current dollar by escalating the actual costs by the increases
9 in nationwide healthcare related costs. The average of the restated Active
10 Healthcare costs was used to adjust the historical test year's Active Healthcare costs
11 to a constant dollar base. In contrast, the self-insured medical costs normalization
12 adjustment addresses solely the medical costs of self-insured claims, which have a
13 history of being the most volatile, as I describe in my Direct Testimony on pages
14 14 through 21. Instead of repricing historical costs for the cumulative impact of
15 changes in nationwide healthcare related costs, the self-insured medical adjustment
16 uses current prices applied to the average historical units of unique medical services
17 provided to the Company employees and dependents.

18 However, based on the response by AG Witness Coppola to a Company Discovery
19 request, it is my understanding that AG Witness Coppola will be revising his
20 testimony to delete the reference to constant dollar averaging and the retroactive
21 inflation. The Discovery question to the Attorney General and the response is
22 reflected on Exhibit A-36, Schedule AA7.

23

24 **Q33. Does this conclude your rebuttal testimony?**

25 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

REBUTTAL TESTIMONY

OF

MATTHEW A. FIX

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF MATTHEW A. FIX

Line
No.

1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed?**

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

6

7 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
8 **Company (DTE Electric or Company)?**

9 A2. Yes.

10

11 **Purpose of Testimony**

12 **Q3. What is the purpose of your rebuttal testimony?**

13 A3. My testimony will rebut the testimony of several witnesses, including:

14 • Attorney General (AG) Witness Coppola’s proposal to exclude incentive
15 compensation expense related to 51% of the operating measures and
16 Association of Businesses Advocating Tariff Equity (ABATE) Witness
17 York’s proposal to exclude incentive compensation expense related to
18 certain operating measures,

19 • Michigan Public Service Commission (MPSC) Staff (Staff) Witness
20 McMillan-Sepkoski’s proposal to exclude Restricted Stock expense,

21 • Witness Bunch on behalf of the Citizens Utility Board and the Natural
22 Resources Defense Council (NRDC-CUB) regarding the 2024 labor
23 escalation rate, and

24 • Staff Witness Rueckert’s proposed adjustment to the Company’s projected
25 Employee Savings Plan (ESP) expense.

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1 The absence of a discussion of other matters in my testimony should not be
2 regarded as an indication that I agree with all other aspects of the Staff's and
3 intervenor's testimony. The narrow focus of my testimony is instead a consequence
4 of a focus on priority issues in recognition of the available resources.

5

6 **Q4. Are you sponsoring any exhibits in this proceeding?**

7 A4. Yes. I am sponsoring, in whole or in part, the following exhibits:

8	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
9	A-55	VV1	AIP/REP 2019-2024 Performance Weighted Results
10	A-55	VV2	Labor Cost Analysis 2019-2024
11	A-55	VV3	ESP Expense 2024 Normalization
12	A-55	VV4	Adjusted ESP Escalation
13	A-55	VV5	Updated Staff ESP Projection

14

15 **Q5. Were these exhibits prepared by you or under your direction?**

16 A5. Yes, they were.

17

18 **Incentive Compensation**

19 **Q6. What is AG Witness Coppola's proposal regarding the Company's incentive**
20 **compensation expense?**

21 A6. AG Witness Coppola proposes the exclusion of 50.6% of the Company's projected
22 Annual Incentive Plan (AIP) and Rewarding Employees Plan (REP) expense
23 related to operating measures of \$20.531 million, which results in a disallowance
24 of \$10.389 million. Instead, AG Witness Coppola proposes that the Company's
25 incentive compensation expense related to the portion excluded from the

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1 Company's revenue requirement be subject to the two-way tracker previously
2 approved by the Commission (Coppola Direct, page 149, lines 12-19 and page 150,
3 lines 1 and 2).
4

5 **Q7. What is the basis for Witness Coppola's proposal to exclude 50.6% of the**
6 **incentive compensation expense related to Operating measures?**

7 A7. Witness Coppola relies on his analysis of the operating performance levels achieved
8 for the years 2020 through 2024 to conclude that 49.4% of these measures achieved
9 performance levels of Target or higher for both AIP and REP for all employee
10 groups, as reflected on Exhibit AG-59.
11

12 **Q8. Do you agree with Witness Coppola's analysis of historical operating**
13 **performance measures?**

14 A8. No. Witness Coppola's analysis of the proportion of measures that were at Target
15 or above is flawed because it fails to recognize how AIP and REP are designed.
16 While certain measures may produce results that are less than Target, other
17 measures can produce results that are greater than Target. Moreover, even those
18 measures where actual performance was less than Target can still generate payouts
19 if the actual performance was higher than the Threshold level. Under the AIP,
20 payouts range from 25% for Threshold performance to 175% for Maximum
21 performance for non-executives, and up to 200% for executives, with 100% payouts
22 for Target performance. Payouts under the REP range from 50% for Threshold
23 performance to 150% for Maximum performance, with 100% payouts for Target
24 performance. Thus, if the actual performance is less than Target but higher than

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1 Threshold, payouts under the AIP would range between 25% and 100% and the
2 REP payouts would range between 50% and 100%.

3

4 These ranges in potential payouts result in Witness Coppola's singular focus on
5 whether actual performance was at Target or above or below Target is an inaccurate
6 representation of the impact of performance on actual payouts. For example, in
7 2021 the Electric OSHA Recordable Incident Rate (RIR) Target was .67 whereas
8 the 2021 actual RIR was .68, which produced a 95.6% AIP payout and a 97.1%
9 REP payout. The difference between the Target of .67 and the actual results of .68
10 represents a variance from Target of only 1.5%. In contrast, Witness Coppola's
11 approach would deem the only 1.5% less than Target to result in a zero payout.
12 This is an unreasonable inference and is inconsistent with the design of the plans.
13 Similarly, Witness Coppola's method ignores the impact of performance above
14 Target, which could result in payouts of up to 150% for the REP and up to 200%
15 for the AIP when Maximum performance levels are achieved. Witness Coppola's
16 exclusive reliance on the achievement of performance relative to Target levels fails
17 to recognize the gradients of performance between Threshold and Maximum
18 performance levels that are the basis for actual payouts.

19

20 **Q9. Have you computed the actual operating performance levels for the same**
21 **period that recognizes the gradients of performance between Threshold and**
22 **Maximum levels?**

23 A9. Yes. Exhibit A-55, Schedule VV1, shows that actual weighted performance for the
24 last five years was 77.2% for the AIP, 79.2% for the AIP Executives, and 69.0%
25 for the REP for a combined average of 75.2%.

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1 **Q10. Is the use of average annual performance, as reflected on Exhibit A-55,**
2 **Schedule VV1, a more accurate depiction of the Company's historical**
3 **performance than the method used by Witness Coppola on Exhibit AG-59?**

4 A10. Yes. The average annual performance method reflected on Exhibit A-55, Schedule
5 VV1 is a more accurate method of measuring historic performance than the
6 approach used by Witness Coppola. Witness Coppola's approach is based on a
7 simplistic binary model, wherein either Target performance was or was not met.
8 Whereas the methodology reflected on Exhibit A-55, Schedule VV1, recognizes
9 that actual payouts can fall within a wide spectrum of performance levels,
10 consistent with the design of the program.

11

12 **Q11. Is it reasonable to assume that only 49.4% of the operating performance**
13 **measures will be achieved in the projected test year?**

14 A11. No. The establishment of costs to be reflected in the Company's revenue
15 requirement is subject to various uncertainties, but the goal is to establish expenses
16 at the levels that are most likely to be incurred. In this instance, it is reasonable to
17 assume that the Company will, on an overall basis, achieve Target performance
18 levels for both the AIP and REP and include all incentive compensation expense
19 related to the operating measures.

20

21 **Q12. Has the Commission addressed the binary method of measuring Operating**
22 **results in prior Orders?**

23 A12. Yes. In the Company's most recent rate case (Case No. U-21534) the Commission
24 addressed an identical proposal of the AG.

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1 “The Commission agrees with the company, based on the record in this case, that
2 the Attorney General’s binary approach of judging a target as met or not ignores
3 that the company employs an incentive payout system that is based on a gradation
4 of meeting targets with threshold, target, and maximum achievement levels.” (Case
5 No. U-21534, January 23, 2025, page 278).

6

7 **Q13. What is ABATE Witness York’s proposal regarding incentive compensation**
8 **expense related to the Operating measures?**

9 A13. ABATE Witness York proposes that the incentive compensation expense related to
10 the Operating measures that don’t have a measurable net customer benefit, to wit:
11 the Customer Satisfaction and Safety measures, be excluded. (York Direct, page
12 16, lines 6 through 11).

13

14 **Q14. Do you agree with ABATE Witness York’s proposal regarding the exclusion**
15 **of incentive compensation expense related to the Customer Satisfaction and**
16 **Safety measures?**

17 A14. No. ABATE Witness York’s proposal is flawed for two reasons. First, ABATE
18 Witness York’s proposal seems to rely on the flawed premise that all of the benefits
19 of the individual measures are capable of precise quantification. Second, ABATE
20 Witness York’s proposal represents an unreasonable interpretation and application
21 of the Commission’s standard that incentive compensation expense is only
22 recoverable if the benefits of the incentive compensation plans exceed the related
23 costs.

Line
No.

1 **Q15. What is the flaw in ABATE Witness York’s apparent assumption that all the**
2 **individual incentive compensation measures are capable of precise**
3 **quantification?**

4 A15. The Cost/Benefit analysis reflected on Exhibit A-21 Schedule K6 represents only
5 the reasonably quantified financial benefits of the Company achieving Target
6 performance for each of the measures included in the incentive compensation plans.
7 For example, the benefits of the Company achieving its Net Promoter Score only
8 reflects the benefits of reductions in customer calls and assigns no measurable value
9 to the benefits to customers that may otherwise be inconvenienced by the
10 Company’s service levels.

11 In addition, while the quantified benefits of the Company achieving its Target
12 performance for the Safety measures is \$1.935 million, this reflects only the
13 measurable benefits to the Company of improved safety performance and excludes
14 any impact on the communities the Company serves. Further, because it would be
15 callous to assign any value to fatalities, the measure of the benefits specifically
16 excludes the immeasurable benefits of avoided fatalities.

17 In summary, ABATE Witness York argues that only measurable benefits should be
18 the basis of determining the net customer benefits of the Company achieving its
19 Operating Targets, which is improper because it presumes that all the benefits of
20 the measures are precisely quantifiable, which they are not. The absence of
21 quantification does not imply the benefits are non-existent.

22

23 **Q16. Why is ABATE Witness York’s interpretation and application of the**
24 **Commission’s incentive compensation Cost/Benefit test requirement**
25 **unreasonable?**

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1 A16. The origins of the Commission's policies regarding the recoverability of incentive
2 compensation can be traced back to its Order in Case No. U-10150, wherein the
3 Commission concluded:

4 "It further finds that the utility should be placed on notice that
5 future approval of an incentive bonus like this requires a showing
6 that it will not result in excessive costs and the benefits to the
7 utility's ratepayers will be commensurate with those costs."
8 (Order, Case No. U-10150, pages 57-58)

9 The Commission has consistently applied the standard articulated in the Order in
10 Case No. U-10150 and assessed the net customer benefits on an aggregate basis
11 without regard to the net benefits for each measure. ABATE Witness York's
12 proposal to only allow recoverability based on each component is unreasonable
13 because it relies only on measurable benefits and is inconsistent with the
14 Commission's traditional practice without any explanation as why a change in
15 practice is either necessary or desirable.

16

17 **Restricted Stock**

18 **Q17. What did Staff Witness McMillan-Sepkoski propose regarding the Company's**
19 **Restricted Stock expense?**

20 A17. Staff witness McMillan-Sepkoski proposes the elimination of \$7.730 million of
21 Restricted Stock expense based on her conclusion that Restricted Stock represents
22 a financial measure, which are routinely disallowed by the Commission (McMillan-
23 Sepkoski Direct, page 7, lines 13 through 15).

24 **Q18. Do you agree with Staff Witness McMillan-Sepkoski's proposal?**

25 A18. No. As I describe in my Revised Direct Testimony on pages 40 and 41, Restricted
26 Stock is completely unrelated to the Company's financial performance. For the

Line
No.

1 sake of brevity, I will not repeat the arguments contained in my Revised Direct
2 Testimony.

3

4 **Q19. Does Staff Witness McMillan-Sepkoski rely on a different rationale for the**
5 **exclusion of the Restricted Stock case than she did in her testimony in the**
6 **Company’s most recent rate case (Case No. U-21534)?**

7 A19. Yes. Staff Witness McMillan-Sepkoski inferred that Restricted Stock was a
8 financial measure in her testimony in Case No. U-21534 because the employee
9 handbook stated that Restricted Stock was a reward for assisting the Company in
10 reaching its financial performance goals. In contrast, in this case Staff Witness
11 McMillan-Sepkoski cites an employee handbook that describes Restricted Stock as
12 a reward to employees for supporting the Company’s business objectives and long-
13 term success.

14

15 **Q20. Does the distinction between “financial performance goals” and “business**
16 **objectives and long-term success” represent a meaningful difference?**

17 A20. Yes. While “financial performance goals” could be viewed as providing a clear
18 nexus to the Company’s financial results, “business objectives and long-term
19 success” refers to all aspects of the Company’s operations, not exclusively
20 financial.

21

22 **Q21. What are the Company’s business objectives?**

23 A21. The best summary of the Company’s business objectives is reflected in the AIP and
24 REP measures contained in my Exhibits A-21, Schedule K2. These measures are
25 indicative of the Company’s priorities.

Line
No.

1 **Q22. Aren't 40% of the Company's AIP and REP measures related to financial**
2 **results?**

3 A22. Yes. While I continue to believe all incentive compensation should be included in
4 the Company's revenue requirement, I also acknowledge the Commission's
5 consistent practice of excluding the AIP and REP incentive compensation expense
6 related to financial measures from the Company's revenue requirement. In light of
7 this, a reasonable alternative to the complete elimination of the Company's
8 Restricted Stock expense is to only disallow 40% of the Restricted Stock expense
9 related to the Financial measures in recognition that 60% of the Company's
10 business objectives pertain to Operating measures. This would result in a
11 disallowance of \$3.092 million of Restricted Stock expense and reduce Staff
12 Witness McMillan-Sepkoski's disallowance by \$4.638 million.

13

14 **Labor Escalation**

15 **Q23. What is NRDC-CUB Witness Bunch's proposal regarding 2024 labor cost**
16 **escalation?**

17 A23. NRDC-CUB Witness Bunch recommends labor inflation for 2024 of 0.23% based
18 on his calculation of the Company's compound average growth in total
19 compensation costs for the period 2019 through 2024 of 0.23% (Bunch Direct, page
20 22, lines 6-10).

21 **Q24. Do you agree with CUB Witness Bunch's recommendation?**

22 A24. No. CUB Witness Bunch's use of the compound annual growth rate in the
23 Company's total compensation of 0.23% for the years 2019 through 2024 is
24 extremely flawed and should be rejected. First, as detailed in the footnote regarding

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Total Compensation on Exhibit CUB-40, page 2 of 2, line 28, the amounts used by CUB Witness Bunch are inclusive of total wages, including incentive compensation and employee benefits. These latter two items are both subject to variability among years and are not predictive of future costs. More importantly, Witness Bunch ignores that the Company's Total Compensation in 2024 was impacted by the Company's VSIP that resulted in a significant reduction in labor costs. Had Witness Bunch measured the compound annual growth rate on a per employee basis rather than total cost, the actual increase in labor costs per employee for the years 2019 through 2024 would be 2.79%, as reflected on Exhibit A-55, Schedule VV2, line 8, column (j), rather than his calculated 0.23%. And, when calculated exclusive of incentive compensation and employee benefits, the compound annual growth rate would be 3.27%, as reflected on Exhibit A-55, Schedule VV2, line 27, column (j). This demonstrates the reasonableness of the Company's 2024 3.50% wage escalation rate projection.

Employee Savings Plan

Q25. What adjustment did Staff Witness Rueckert propose to the Company's projected Employee Savings Plan expense?

A25. Staff Witness Rueckert used the Company's 2024 actual Employee Savings Plan (ESP) costs of \$49.145 million and escalated by 2.44% annually based on a five-year average of the annual change in the Company's ESP costs for the years 2019 through 2024 resulting in a projected ESP cost of \$51.577 million or \$27.621 million of ESP expense after adjusting for the portion of ESP costs capitalized (Rueckert Amended Direct, page 6, lines 1 through 17, Exhibit S-24.3).

Line
No.

1 **Q26. Do you agree with Staff Witness Rueckert's proposed adjustment to the**
2 **Company's projected ESP expense?**

3 A26. No. Staff Witness Rueckert's use of the Company's 2024 ESP expense as a starting
4 point is improper because the Company instituted a change in accounting practices
5 for the recognition of ESP forfeitures for employees who depart the Company prior
6 to their being vested. Previously, the Company recognized the impact of employee
7 forfeitures in the year subsequent to forfeiture. In 2024, the Company began
8 recognizing the impact of forfeitures in the year the employee departed the
9 Company. As a result, in 2024 the Company recognized employee ESP forfeitures
10 related to both 2023 and 2024. This results in an unreasonably low ESP cost in
11 2024 that must be adjusted to develop a proper starting point for escalations through
12 the end of the projected test year. Staff Witness Rueckert also ignored the impact
13 of lag hiring in 2024 on ESP expense, as explained by Company Witness Cooper
14 and as reflected on Exhibit A-36, Schedule AA1.

15

16 **Q27. Have you quantified the impact of the recognition of two years of ESP**
17 **forfeitures in 2024?**

18 A27. Yes. Exhibit A-55, Schedule VV3, reflects the normalization of the 2024 ESP costs
19 to eliminate the 2024 forfeitures which increases the 2024 cost by \$1.341 million.
20 While this excludes the 2024 forfeitures, forfeitures related to 2023 of \$1.425
21 million remain in the 2024 ESP costs. This normalization merely avoids the
22 inclusion of an excess year of forfeitures. In addition, 2024 ESP costs must be
23 adjusted for the impact on ESP of lag hiring in 2024, as described by Company
24 Witness Cooper. The inclusion of the normalization of 2024 ESP costs increases
25 the five-year average from the 2.44% used by Staff witness Rueckert to 3.54%

Line
No.

1 **Q28. Have you prepared an alternative analysis of the Company's Employee**
2 **Savings Plan expense?**

3 A28. Yes. Exhibit A-55, Schedule VV5 reflects an update of Staff Exhibit S-24.3 that
4 includes the impact of normalizing the 2024 ESP costs for the excess forfeitures in
5 2024, the impact of Lag Hiring as described by Company Witness Cooper and the
6 use of the 3.54% ESP annual escalation rate from Exhibit A-55, Schedule VV4.
7 This results in ESP cost for 2026 of \$55.612 million, or after adjustment for the
8 portion of ESP costs capitalized results in ESP expense for 2026 of \$29.780 million,
9 which is \$2.159 million higher than the ESP expense proposed by Staff Witness
10 Rueckert.

11

12 **Q29. Does this conclude your rebuttal testimony?**

13 A29. Yes, it does.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of)
DTE ELECTRIC COMPANY)
for authority to increase its rates, amend)
its rate schedules and rules governing the)
distribution and supply of electric energy, and)
for miscellaneous accounting authority.)

Case No. U-21860

REBUTTAL TESTIMONY

OF

THERESA M. UZENSKI

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF THERESA M. UZENSKI

Line
No.

1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed?**

3 A1. My name is Theresa M. Uzenski. I am employed by DTE Energy Corporate
4 Services, LLC, a subsidiary of DTE Energy Company (DTE Energy). My business
5 address is One Energy Plaza, Detroit, MI 48226.

6

7 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
8 **Company (DTE Electric or Company)?**

9 A2. Yes.

10

11 **Purpose of Testimony**

12 **Q3. What is the purpose of your rebuttal testimony?**

13 A3. The purpose of my rebuttal testimony is to refute certain positions taken by the
14 other parties as follows. The absence of a discussion of other matters in my
15 testimony should not be taken as an indication that I agree with all other aspects of
16 intervenor testimony. More specifically, I provide rebuttal on the following topics:

- 17 • If shared asset capital projects (i.e., projects that are to be utilized by more than
18 one DTE Energy company) are disallowed by the Michigan Public Service
19 Commission (MPSC or Commission), then the related shared asset revenue
20 included in projected net operating income must be reduced for the amounts
21 that will not be billed to affiliated entities.
- 22 • Staff's increase in other operating revenues should be rejected because it is
23 inconsistent with the practice approved by the MPSC in previous rate cases.

Line
No.

- 1 • The Attorney General's (AG) proposed disallowance of the vehicle fleet capital
2 expenditures should be rejected because the Company's forecast method is
3 more accurate than using the 2025 average cost calculated by the AG.
- 4 • The AG's proposed disallowance of renovation work at the Headquarters Plaza
5 should be rejected because the project design is nearly complete and it remedies
6 existing structural problems.
- 7 • Staff's disallowance of capitalized overheads on IT projects must be rejected
8 because it violates standard accounting practices as required by the MPSC
9 Uniform System of Accounts (USoA).
- 10 • Any disallowances of capital projects going in-service beyond the projected test
11 period should not have an impact on the revenue requirement because the cost
12 is offset by an AFUDC credit in projected net operating income.
- 13 • The AG's proposal to increase the regulatory liability for deferred incentive
14 compensation and the related amortization expense should be rejected because
15 the calculation is inaccurate and inconsistent with the design of the approved
16 mechanism. My testimony supports the correct calculations.
- 17 • The AG, Michigan Environmental Council (MEC), and Natural Resource
18 Defense Council's (NRDC) (collectively, AG-MN) assertion that the Company
19 should not be capitalizing certain costs related to its Pole and Pole Top
20 Maintenance and Modernization program (PTMM) is inaccurate. My
21 testimony will demonstrate that the Company's capitalization policies are
22 consistent with the requirements of the USoA.
- 23 • Staff proposed a disallowance of property costs for certain 4.8kV Circuit
24 Conversion projects if the Company does not provide clear documentation of
25 its accounting treatment. The Company's accounting policy is to comply with

Line
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1 the USoA. My Rebuttal Exhibit A-37, Schedule BB5 provides the relevant
2 excerpt.

3 • The AG's general claims that the Company is improperly capitalizing costs are
4 baseless and should be disregarded.

5 • MEC, NRDC, and the Citizens Utility Board of Michigan's (CUB)
6 (collectively, MNC) suggestion that the undepreciated balance of certain
7 distribution assets that are retired be recorded as a deferred asset for future
8 securitization should be rejected. The correct accounting treatment is to reflect
9 the balance in net plant and adjust future depreciation rates if needed.

10

11 **Q4. Are you sponsoring any exhibits in this proceeding?**

12 A4. Yes. I am sponsoring the following exhibits:

13	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
14	A-37	BB1	Shared Asset Adjustment for Proposed
15			Disallowances
16	A-37	BB2	Fleet Vehicle Purchases
17	A-37	BB3	2024 Incentive Deferral
18	A-37	BB4	Capital Overheads
19	A-37	BB5	Land Costs
20	A-37	BB6	DEMNSC-1.5

21

22 **Q5. Were these exhibits prepared by you or under your direction?**

23 A5. Yes, they were.

Line
No.

1 **Revenue**

2 **Q6. What did the Company forecast for Shared Asset revenue?**

3 A6. As shown on my Exhibit A-13, Schedule C3, line 14, the Company forecasted \$63.5
4 million of revenue from shared assets such as building and information technology
5 with its affiliates. The assets are reflected in rate base for DTE Electric, but the
6 revenue requirement is reduced by the amount billed to DTE Energy affiliates for
7 their usage of the assets.

8

9 **Q7. What is the impact to Shared Asset revenue if the Commission disallows the**
10 **underlying assets?**

11 A7. Since the projected revenue assumes the capital projects supported in the instant
12 case are approved, the revenue projection needs to be reduced for the impact of any
13 capital disallowances of shared assets. The reduction to shared asset revenue for
14 each project proposed for disallowance is shown in my Rebuttal Exhibit A-37,
15 Schedule BB1, column (f), for a total of \$1.1 million on line 15. If the Commission
16 disallows a capital project that is for a shared asset, then it must also remove the
17 revenue related to that asset from projected net operating income.

18

19 **Q8. What adjustment to other operating revenues did Staff propose?**

20 A8. At the top of page 5 of his direct testimony, Staff Witness Isakson proposed an
21 increase to present revenues of \$2.7 million based on historic trends in other
22 operating revenue.

Line
No.

1 **Q9. Do you agree with Witness Isakson's proposed increase?**

2 A9. No. Other operating revenues include late payment fees, service request fees and
3 other miscellaneous charges that are impacted by customer payment patterns and
4 the level of customer service requests. Such impacts could result in increased or
5 decreased revenue on a year-over-year basis. Accordingly, the Company held the
6 revenue in the projected period to the same amount experienced in the historical
7 period, consistent with the methodology used in prior rate cases. The Commission
8 has historically approved the Company's projected other operating revenues based
9 on this method and should approve the Company's as-filed amount in the instant
10 case.

11

12 **Capital Expenditures**

13 **Q10. What disallowances related to vehicle fleet capital expenditures have been**
14 **proposed by the AG?**

15 A10. On page 66, line 11 of his direct testimony, AG Witness Coppola proposes
16 disallowances of capital expenditures totaling \$22.6 million for fleet purchases. His
17 argument is based on taking an assumed average cost per vehicle of \$144,000 from
18 2025, adjusting for inflation of 2.4% for a total of \$148,000, and multiplying by
19 299 units to be purchased in 2026 to yield a capital forecast for 2026 of \$44.3
20 million. The difference between Witness Coppola's calculated forecast and the
21 Company's projection of \$66.8 million serves as the basis for his proposed
22 disallowance of \$22.6 million.

Line
No.

1 **Q11. Do you agree with AG Witness Coppola's estimate of projected costs?**

2 A11. No. The Company acknowledges that the data provided may not have been clear
3 as to the number of units being purchased, which led to Witness Coppola
4 calculating an incorrect \$144,000 cost per vehicle for 2025. See my Rebuttal
5 Exhibit A-37, Schedule BB2, pages 2 through 11 for the relevant pages from the
6 Company's response to discovery question AGDE-8.220b. Witness Coppola took
7 the total capital cost for the year and divided it by the number of lines with cost
8 items in the Excel file provided by the Company to calculate a historical cost per
9 unit. However, this is a flawed approach because he unknowingly double counted
10 some units. His analysis also did not consider the mix in the type of vehicles to be
11 purchased in 2026.

12

13 **Q12. Why would using the number of lines in the file result in a double count of**
14 **some units?**

15 A12. First, I need to clarify what a vehicle or mobile unit is for context. The Company
16 defines one unit as consisting of both the chassis (base frame) and the upfit
17 (required accessories and modifications). Prior to 2026, these components were
18 often purchased separately—sometimes in different fiscal years, with the chassis
19 being purchased first and then subsequently followed by the upfit of the vehicle.
20 The file provided by the Company had the cost of the chassis and the upfit on
21 separate lines, reflecting the individual purchases. Thus, Witness Coppola
22 identified a chassis as one unit and the upfit as a separate unit. Please see my
23 Rebuttal Exhibit A-37, Schedule BB2, page 1, Table 1, which uses the same 2025
24 cost data given to Witness Coppola in discovery, updated to reflect the correct
25 number of units.

Line
No.

1 **Q13. What is the correct number of units for 2025?**

2 A13. See pages 12 through 14 of my Rebuttal Exhibit A-37, Schedule BB2 for the
3 updated details and unit count. I recalculated the number of units by applying either
4 a full unit (both the chassis and upfit) or 0.5 units for the purchase of either the
5 chassis or the upfit. Utilizing this methodology, the data reflects 87.5 complete
6 units purchased for 2025 instead of the 172 assumed by Witness Coppola.

7
8 **Q14. What is the corrected composite average cost for 2025 and the 2026
9 projection?**

10 A14. As shown on my Rebuttal Exhibit A-37, Schedule BB2, page 1, Table 1, the total
11 cost of capital investment in 2025 (\$24.9 million) divided by the number of units
12 calculated (87.5) yields an average cost per unit of \$284,000. Applying Witness
13 Coppola's methodology of multiplying the average unit price (corrected to
14 \$284,000) by 299 units, results in a forecast of \$84.9 million. This is far and above
15 the \$66.6 million projected by the Company. Even though the calculation is higher
16 than what was originally filed there is still a mix component of purchasing vehicles
17 that Witness Coppola did not consider, thus making this calculation oversimplistic.

18
19 **Q15. How does the mix of vehicle types impact the 2026 projection?**

20 A15. Rebuttal Exhibit A-37, Schedule BB2, page 1, Table 2 demonstrates that the cost
21 per unit for 2025 varies from approximately \$36,000 to over \$500,000, depending
22 on the type of asset. In Table 3, the Company separates out six different
23 classifications of purchases projected for 2026. The Company will purchase heavy
24 duty vehicles, medium duty vehicles, light duty vehicles, power operated
25 equipment, cable reel trailers and regular trailers. It will also purchase EV

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1 infrastructure. The unit cost for 2026 differs from the unit cost in 2025 because of
2 the mix of vehicles even within the categories. For example, the cost for medium
3 duty trucks depends on how much equipment is added to the basic vehicle. The
4 cost variances are explained in Table 3.

5

6 **Q16. What do you conclude regarding Witness Coppola's proposed disallowance of**
7 **capital expenditures on fleet?**

8 A16. I have identified two issues with Witness Coppola's calculations. His unit cost did
9 not reflect the correct number of units to be purchased in 2025 and did not consider
10 the vehicle classification mix that can drive the composite unit cost to either
11 increase or decrease based on quantity and price derived within each bucket.
12 Recognizing these two flaws in Witness Coppola's calculation, the Commission
13 should reject his proposed \$22.6 million disallowance of fleet capital expenditures.

14

15 **Q17. What is the Attorney General's proposed disallowance for the plaza**
16 **renovation project?**

17 A17. Starting at line 7 on page 61 of his direct testimony, AG Witness Coppola proposes
18 disallowances of capital expenditures totaling \$7.8 million for the plaza renovation
19 project. On page 61, at line 14, he asserts the Company did not provide a clear and
20 compelling case as to why the expenditure was needed.

21

22 **Q18. How do you respond to AG Witness Coppola's proposed disallowance?**

23 A18. I disagree with the proposed disallowance. The Company has already initiated
24 design work for the plaza renovation project and plans to solicit bids in the fourth
25 quarter of 2025. The pipes and plumbing of the plaza are all original from when

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1 the plaza was first built back in 1972. In addition to the pipes and plumbing, the
2 first and second floors of the plaza at the Detroit headquarters will need to be
3 renovated. The first and second floors do not meet current city and state building
4 codes due to outdated infrastructure. Given these issues, the Company considers
5 this project necessary and prudent to complete. The Commission should approve
6 the Company's request for \$7.8 million for this project.

7

8 **Q19. What does Staff propose regarding overhead costs on IT capital projects?**

9 A19. Starting at line 3 on page 17 of her direct testimony, Staff Witness Rogers discusses
10 IT projects and "recommends a full disallowance of the 'Projected Capital
11 Overhead and Other Costs (Capital)' for all projects with spend not already
12 approved in Case Number U-21534." She proposed a disallowance of \$0.731
13 million in 2023, \$3.231 million in the bridge period, and \$11.542 million in 2026
14 for overheads applied to IT projects. Starting at line 19 on page 17, she asserts that
15 the Company did not justify the expense and did not provide details on how the
16 overhead costs were used or why they were necessary for the implementation of
17 specific IT projects.

18

19 **Q20. Do you agree with Staff Witness Rogers' proposed disallowance?**

20 A20. No. Overhead costs are expenses of a business that are not directly related to
21 constructing an asset or providing a service. They are recurring, indirect costs.
22 Overheads are one component of an asset and by definition, the application of
23 overheads to a project cannot be described in terms of a specific function or impact.
24 Overhead costs are routinely allocated to all capital projects executed by the
25 Company, including distribution, generation, general plant and IT projects.

Line
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1 **Q21. What is the accounting treatment for overhead costs?**

2 A21. The Company provided a list of overhead expenses in response to the discovery
3 that is included in Staff Exhibit A-12.9. These types of costs are accumulated in
4 total and then allocated to capital projects, generally by applying an overhead rate
5 to construction charges such as direct labor or materials.

6

7 **Q22. Does the USoA allow for the capitalization of overhead costs?**

8 A22. Yes. In fact, it requires it. The USoA Electric Plant Instruction item 4, Overhead
9 construction costs, states the following: "All overhead construction costs, such as
10 engineering, supervision, general office salaries and expenses, construction
11 engineering and supervision by others than the accounting utility, law expenses,
12 insurance, injuries and damages, relief and pensions, taxes and interest, shall be
13 charged to particular jobs or units on the basis of the amounts of such overheads
14 reasonably applicable thereto, to the end that each job or unit shall bear its equitable
15 proportion of such costs and that the entire cost of the unit, both direct and
16 overhead, shall be deducted from the plant accounts at the time the property is
17 retired." It appears that Staff agrees that overheads are an appropriate capital cost.
18 Please see my Rebuttal Exhibit A-37, Schedule BB4 that contains Staff's responses
19 to discovery on this topic.

20

21 **Q23. If Staff Witness Rogers agrees that overheads are an appropriate capital cost,**
22 **what is the basis for her proposed disallowance?**

23 A23. Witness Rogers stated in direct testimony starting at line 5 on page 18, "Staff
24 questions how the projected overhead cost can be derived for an investment if there
25 is not a breakdown of which overhead purposes are necessary for implementation

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1 and their projected value. Additionally, for investments already implemented, the
2 Company should have a contract, receipt, or a breakdown of the costs and which
3 dollars applied to the ‘Projected Capital Overhead and Other Costs (Capital)’
4 category.” It appears Staff does not fully understand the nature of overhead costs.
5 There is no receipt, contract, or other specific overhead cost item that can be traced
6 back for each IT investment, as suggested by Witness Rogers. There is no
7 “overhead purpose” for individual projects, as requested in discovery by Witness
8 Rogers.

9
10 In response to discovery question Staff-2.9, included in my Rebuttal Exhibit A-37,
11 Schedule BB4, Staff admits that costs “cannot be directly traced to a specific asset.
12 However, Staff is unclear how the overheads and allocations are determined by the
13 Company to project the overhead costs *for each IT investment.*” (Emphasis added.)
14 This response seems contradictory – Staff Witness Rogers says she understands
15 that overhead costs cannot be traced but still expects specific cost information for
16 individual IT projects.

17
18 **Q24. Should the Commission approve Staff’s recommended disallowance of**
19 **overhead costs for IT capital projects?**

20 A24. No. The Commission has consistently approved the inclusion of overhead costs in
21 all capital projects, including information technology projects, consistent with the
22 accounting rules outlined in the USoA. Staff’s recommendation has no basis in
23 accounting or ratemaking standards and must be rejected.

Line
No.

1 **Q25. Did any of the parties to this case propose a reduction in rate base for projects**
2 **not going in service during the projected test period?**

3 A25. Yes. The MPSC Staff, AG and Association of Businesses Advocating Tariff Equity
4 (ABATE) have proposed disallowances of projects that are not in service during
5 the projected test period.

6
7 **Q26. What impact should a disallowance of projects that do not go into service**
8 **during the projected test period have on the Company's requested rate relief?**

9 A26. Such disallowances should not have any impact. As discussed in my revised direct
10 testimony, AFUDC is added to the asset being constructed with a corresponding
11 credit to the income statement. Including the credit to income from AFUDC offsets
12 the impact of including CWIP in rate base; therefore, projects that do not go into
13 service during the projected test period have no impact on the Company's revenue
14 requirement and deficiency. To ensure that is the result, either the proposed
15 disallowances for projects not going into service should be excluded from any
16 reductions to rate base approved by the Commission, or a corresponding adjustment
17 (reduction) in pre-tax AFUDC should be added to offset the removal of the projects
18 from approved rate base.

19

20 **Incentive Compensation - Amortization Expense**

21 **Q27. What is the Attorney General's recommended adjustment to the 2024 deferred**
22 **incentive compensation and related amortization expense?**

23 A27. AG Witness Coppola discusses this starting at line 6 on page 135 of his direct
24 testimony. Witness Coppola proposes an amortization credit of \$1.084 million
25 compared to the Company's projected credit amount of \$0.459 million, resulting in

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1 a net decrease to O&M of \$625,000. This difference relates to the recoverable
2 amount assumed for actual 2024 performance, as shown on Witness Coppola's
3 Exhibit AG-55, page 2, line 2, and the resulting deferred asset of \$1.365 million
4 shown on line 4.

5
6 The Company supported a balance of \$4.491 million for 2024, representing the
7 difference between the amount of incentive compensation related to operating
8 metrics approved in Case No. U-21297, and the forecasted expense based on
9 achieving the targeted results. This is shown on my Exhibit A-13, Schedule
10 C5.10.1, column (e), line 3. The Company subsequently reduced the 2024 balance
11 by \$152,000 from its original filing to reflect an adjustment to the 2024 layer
12 recorded in 2025. See my Rebuttal Exhibit A-37, Schedule BB3, page 5, line 3,
13 column (e), supporting the revised balance of \$4.339 million.

14

15 **Q28. How did Witness Coppola calculate the \$1.365 million amount?**

16 A28. As shown on his Exhibit AG-55, page 2, Witness Coppola calculates a percentage
17 based on the number of 2024 operational measures achieved. He applies that
18 percentage to the potential incentive compensation approved in U-21297 to
19 determine the amount he suggests is recoverable - \$11.507 million, shown on line
20 2. He then compares that amount to the base shown on line 3, resulting in a
21 difference of \$1.365 million on line 4.

22

23 **Q29. Do you have any concerns with the AG's calculations?**

24 A29. Yes. Witness Coppola is assuming performance results of 59.0%. These figures
25 are based on the number of metrics at Target or better. This calculation is flawed

Line
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1 because it assumes all the operating metrics underlying the incentive compensation
2 plan are based on whether performance Targets were met or not met (i.e., binary).
3 In fact, a performance weighted average is the basis for the actual incentive
4 compensation plan payouts that recognizes there are gradients between the
5 Threshold and Maximum performance levels, as more fully explained by Company
6 Witness Fix, rather than Witness Coppola's simplistic binary method.

7

8 The recognition of the gradients in performance can be seen on Company Witness
9 Fix's Exhibit A-21, Schedule K2 in the instant case. Applying the weighting used
10 in the plan design, 2024 actual results averaged 81%, ranging from 68% to 99%, as
11 shown on my Rebuttal Exhibit A-37, Schedule BB3, pages 2 through 4. The results
12 summary and payout calculations are shown on page 1.

13

14 **Q30. Has the Commission approved the deferred incentive compensation**
15 **calculation that reflects weighted results for the targets?**

16 A30. Yes. The Commission approved recoverable incentive compensation within the
17 mechanism based on a weighting of metric results in its January 23, 2025 Order in
18 Case No. U-21534. Page 278 of the Order states, "The Commission agrees with
19 the company, based on the record in this case, that the Attorney General's binary
20 approach of judging a target as met or not ignores that the company employs an
21 incentive payout system that is based on a gradation of meeting targets with
22 threshold, target, and maximum achievement levels."

Line
No.

1 **Q31. What is the appropriate amount of recoverable incentive compensation for**
2 **2024?**

3 A31. As shown on my Rebuttal Exhibit A-37, Schedule BB3, page 1, line 14, column
4 (g), the amount related to 2024 performance is \$14.3 million instead of the \$11.5
5 million calculated by AG Witness Coppola. The payout percentages in column (b)
6 are from the weighted results shown on pages 2 through 4. In columns (h) and (i)
7 I demonstrate that if the actual results percentages were applied to the projected
8 expense of \$19.5 million from U-21297 (and used by Witness Coppola in his
9 calculations), the payout amount for 2024 would be \$15.5 million, as shown on line
10 14.

11

12 **Q32. Did the Company record \$15.5 million as the amount related to 2024**
13 **performance?**

14 A32. No. The actual amount recorded to expense for 2024 was \$14.3 million (plus
15 \$214,000 for prior period revisions for a total \$14.5 million). The lower amount of
16 expense was caused by various factors including the use of updated salaries, the
17 mix of employee positions (incentive targets vary by pay grade), variances in the
18 amount allocated from the LLC, and variances in the amount capitalized.

19

20 **Q33. What is the appropriate amount of the deferred incentive compensation for**
21 **2022 through 2024?**

22 A33. Please refer to my Rebuttal Exhibit A-37, Schedule BB3, page 5. The 2022
23 regulatory asset is \$750,000 and the 2023 regulatory liability is \$7.537 million (as
24 originally filed). The 2024 regulatory asset is \$4.339 million which is the
25 difference between the recoverable amount \$14.5 million just discussed, and the

Line
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1 \$10.1 million base. (See column (e).) The cumulative balance for 2022 through
2 2024 is a regulatory liability of \$2.448 million.

3

4 **Q34. What is the resulting annual amortization expense?**

5 A34. The Company originally reflected an amortization credit of \$0.459 million. After
6 including the 2025 adjustment to the 2024 layer, the annual credit to O&M should
7 be \$0.490 million (instead of the \$1.084 million proposed by Witness Coppola) as
8 shown on my Rebuttal Exhibit A-37, Schedule BB3, page 5, line 8, column (h).
9 The Commission should reject Witness Coppola's proposed \$625,000 increase to
10 the amortization credit and instead increase the credit by \$31,000 to reflect the
11 Company's updated 2024 actual results.

12

13 **Pole & Pole Top Maintenance and Modernization (PTMM) Program Capitalization**

14 **Q35. What does AG-MN assert regarding the Company's accounting practices**
15 **related to the PTMM program?**

16 A35. AG-MN Witness Stephens alleges two violations of the USOA in DTE Electric's
17 accounting for the PTMM. Starting on page 50, line 18, AG-MN Witness Stephens
18 states, "First, routine activities that comprise a substantial part of PTMM program
19 costs, including testing, pole top inspections, and the vegetation management
20 required to complete these, are required by the USOA to be expensed as routine
21 operations and maintenance ('O&M') costs." On page 51, starting on line 4, he
22 states, "Second, the USOA specifies that minor repairs and replacements of
23 equipment should be expensed, not capitalized. While the USOA considers poles
24 to be a major item that should be capitalized, I consider replacements of pole top

Line
No.

1 equipment, including crossarms, insulators, cut-outs, lightning arrestors, and
2 similar, to be minor repairs and replacements.”

3

4 **Q36. Do you agree with AG-MN Witness Stephens that testing, pole top inspections,**
5 **and vegetation management included in the PTMM program are required to**
6 **be expensed?**

7 A36. First, the premise of Witness Stephens’ assertion is incorrect. On page 50 of his
8 direct testimony, at footnote number 62, Witness Stephens references Company
9 Exhibit A-28, Schedule R3. This is a program benefit cost analysis (BCA) report
10 prepared by a consulting firm, 1898 & Company. As explained in the rebuttal
11 testimony of Company Witness De Stigter, the BCA report does not make a
12 distinction between capital costs and maintenance costs. Thus, it cannot be
13 assumed that the costs described are being capitalized. The cost of inspections
14 related to the PTMM program has been expensed as incurred starting in 2023. As
15 supported by Company Witness Robinson’s rebuttal testimony, once an inspector
16 finds that capital work is needed, the initial planning for that work begins. It is at
17 that point that capitalization starts. Regarding pole testing, only those tests that
18 lead to a pole replacement (a capital job) are capitalized.

19

20 Regarding vegetation management, I disagree with Witness Stephens that all such
21 costs must be charged to expense. The Company capitalizes costs directly related
22 to executing its capital PTMM program, and the tree trim work required for safe
23 access to the pole and equipment is being completed to construction specifications
24 (an expanded clearance area). The USoA says that the cost of equipment shall
25 include “expenses incurred by the utility in unloading and placing the equipment in

Line
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1 readiness to operate.” Tree trimming and other vegetation management required to
2 install capital assets is clearly an expense incurred to place equipment in readiness
3 to operate.

4

5 **Q37. Does the accounting for tree trimming and vegetation management related to**
6 **the PTMM program also apply to the 4.8kV hardening and conversion**
7 **programs?**

8 A37. Yes. AG-MN Witness Alvarez alleges starting on line 9 on page 12 of his direct
9 testimony that DTE Electric is capitalizing tree trimming in its 4.8kV programs in
10 violation of FERC’s USoA. I disagree with this claim for the reasons I just
11 described in my discussion of the PTMM program. Tree trimming and vegetation
12 management are required to safely access and install any equipment as part of a
13 capital project should be capitalized.

14

15 **Q38. Do you agree with AG-MN Witness Stephens’ interpretation of the USoA as it**
16 **relates to minor repairs and replacements?**

17 A38. No. While Witness Stephens is correct that minor repairs and replacements should
18 be expensed, he ignores the definition of minor items. Per the USoA, “*minor items*
19 *of property* means the associated parts or items of which retirement units are
20 composed.” Per the USoA, “*retirement units* means those items of electric plant
21 which, when retired, with or without replacement, are accounted for by crediting
22 the book cost thereof to the electric plant account in which included.”

23

24 **Q39. What determines whether an asset is a retirement unit?**

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1 A39. Whether an asset is a retirement unit or minor item is not a matter of Witness
2 Stephens' opinion. The USoA plant instruction 10. A states, "For the purpose of
3 avoiding undue refinement in accounting for additions to and retirements of electric
4 plant, all property will be considered as consisting of (1) retirement units and (2)
5 minor items of property. Each utility shall maintain a written property units listing
6 for use in accounting for additions and retirements of electric plant and apply the
7 listing consistently." The retirement unit listing is generally reviewed by the
8 Commission during depreciation cases.

9

10 **Q40. Are the items listed by Witness Stephens retirement units?**

11 A40. Yes. Pole top equipment, including crossarms, insulators, cut-outs, lightning
12 arrestors, and similar items are retirement units in the Company's list under USoA
13 plant instruction 10. A.

14

15 **Q41. What is the appropriate accounting treatment for pole top equipment?**

16 A41. The USoA Electric Plant Instruction item 10, Additions and Retirements of Electric
17 Plant, part B(1) establishes, "When a retirement unit is added to electric plant, the
18 cost thereof shall be added to the appropriate electric plant account." Part B(2)
19 further states, "When a retirement unit is retired from electric plant, with or without
20 replacement, the book cost thereof shall be credited to the electric plant account in
21 which it is included." Therefore, the items being replaced as part of the PTMM
22 program which are retirement units, including crossarms, insulators, cut-outs,
23 lightning arrestors, and similar items, must be classified as plant. The new asset is
24 added to plant and the existing asset is retired (credited) from plant.

25

Line
No.

1 **Q42. Is AG-MN Witness Stephens' reference Electric Plant Instruction 10.C.3**
2 **relevant to the capitalization of minor items?**

3 A42. No. At line 5 on page 51 of Witness Stephens' direct testimony there is a footnote
4 reference 65. Footnote 65 describes the accounting for substantial betterments of
5 minor items of property outlined in the USoA Electric Plant Instructions. This
6 accounting policy allows for the capitalization of the increased cost of upgrading a
7 minor item of plant. Witness Stephens refers to this exception starting at line 12
8 on page 51 of his testimony to support the capitalization of the price difference
9 between new fiberglass and polymer equipment and old wooden and porcelain
10 equipment. The capitalization of just the incremental cost would only apply to
11 assets that are minor items, but as I previously stated, the assets in question
12 (crossarms, insulators, etc.) are retirement units. Therefore, the entire cost of the
13 assets should be capitalized.

14

15 **Capitalization Policies**

16 **Q43. What does Staff Witness Shi say regarding the accounting for property that**
17 **will be acquired as part of the Company's proposed 4.8kV Circuit Conversion**
18 **(CC) projects?**

19 A43. At line 4 on page 26 of her direct testimony regarding the Grosse Pointe – North
20 CC project, Staff Witness Shi “notes that the property acquisition costs require clear
21 itemization and accounting treatment.” At line 6 on page 27 of her direct testimony
22 regarding the Melvindale CC project, Witness Shi proposes a reduction unless the
23 Company provides more information including “a clear capitalization policy
24 showing the appropriate classification of property acquisition costs.”

25

Line
No.

1 **Q44. Does the Company have a capitalization policy for property acquisition costs?**

2 A44. Yes. The Company's capitalization policy is to follow the USoA Electric Plant
3 Instructions. Item 7, Land and Land Rights, lists the items to be included in the
4 land accounts. Please see my Rebuttal Exhibit A-37, Schedule BB5 for the list of
5 items.

6

7 **Q45. What does AG-MN Witness Alvarez claim regarding DTE Electric's**
8 **capitalization policies?**

9 A45. Starting at line 11 on page 12 of his direct testimony, Witness Alvarez claims,
10 without any basis, that the Company is inappropriately capitalizing costs to earn
11 profits. Witness Alvarez states at line 1 on page 14 of his direct testimony that he
12 provides "no associated recommendations" but he asks the Commission to
13 "consider these audit observations" as it reviews his testimony.

14

15 On page 18, at line 9, he argues that the audit of DTE Electric's (and Consumers
16 Energy Company's) electric distribution system ordered by the Commission in
17 Case No. U-21305 was incomplete. He suggests that the scope of work should have
18 included a forensic audit of the Company's spending decisions related to its
19 distribution system and an accounting audit "to investigate whether DTE
20 accounting practices comply with the Uniform System of Accounts (USOA)
21 maintained by the Federal Energy Regulatory Commission (FERC)." At line 13 on
22 page 19, he asserts that an independent audit of the Company's accounting practices
23 would reveal that the Company "capitalizes many routine, recurring operations and
24 maintenance activities that the USOA specifies should be categorized as O&M
25 expenses."

Line
No.

1 **Q46. Do you agree with AG-MN Witness Alvarez's suggestion that an accounting**
2 **audit is necessary?**

3 A46. No. The Company follows the accounting requirements outlined in the USoA as
4 well as Generally Accepted Accounting Principles (GAAP). It also maintains
5 internal control systems in compliance with the Sarbanes-Oxley Act of 2002. The
6 Company's books and internal controls are audited by an external public accounting
7 firm – PricewaterhouseCoopers (PwC). Additionally, the MPSC Staff audits the
8 Company's financial information as part of each rate case. Witness Alvarez's broad
9 claims that the Company's accounting practices are improper are speculative and
10 without merit. Therefore, the Commission should not consider Witness Alvarez's
11 baseless claims as it evaluates the Company's proposed capital investments and its
12 request for rate relief.

13

14 **Accounting for Retired Assets**

15 **Q47. What accounting treatment does MNC Witness Jester propose for distribution**
16 **assets that are being retired as part of the 4.8kV conversion program?**

17 A47. Starting at line 16 on page 27 of his direct testimony, Witness Jester states, "the
18 decommissioning of equipment will include retirement units that are not yet fully
19 depreciated. Those retirement units should properly be treated as stranded assets
20 and securitized." Starting at line 13 on page 28, he recommends that the net book
21 value of all assets retired during distribution system conversions be placed in a
22 deferred asset account and subsequently securitized.

23

24 **Q48. How does MNC Witness Jester propose to determine the net book value for**
25 **the assets that will be retired?**

Line
No.

1 A48. Please refer to my Exhibit A-37, Schedule BB6 which is a copy of a Witness
2 Jester's response to discovery question DEMNSC-1.5. He suggests the Company
3 calculate the net book value of mass assets based on an average value in the account.
4 For other assets, he suggests using the difference between the original cost and
5 accumulated depreciation.
6

7 **Q49. Do you agree with Witness Jester's proposed net book value calculation**
8 **methodology?**

9 A49. No. Witness Jester assumes there will be an undepreciated balance remaining for
10 the assets being retired. However, the nature of mass assets is such that they are
11 not tracked individually. The accounting system does not track the specific location
12 or in-service date for each item. Thus, a net book value for any individual asset
13 within a group of mass assets cannot be calculated. Using a calculated average for
14 the entire account could result in an assumed net book value for the retired assets
15 that is too high if the assets being retired are significantly older than the assets that
16 are not being retired. Furthermore, because distribution assets are depreciated using
17 the group method, regardless of whether they are mass assets or tracked assets, the
18 net book value (even if it could be calculated) is irrelevant.
19

20 **Q50. Why is the net book value irrelevant under the group depreciation method?**

21 A50. Utilities employ group depreciation for pools of homogeneous assets. Depreciation
22 of individual assets (or retirement units) is not recorded or tracked. Rather, a
23 depreciation rate is applied to the balance (group) of all assets in a summary plant
24 account (e.g., station equipment, poles towers and fixtures, overhead conductors

Line
No.

1 and devices, line transformers, services, etc.). Depreciation rates are periodically
2 reviewed by the Commission (in depreciation cases) and updated if needed.

3

4 **Q51. What would cause group depreciation rates to be updated?**

5 A51. An update to the depreciation rate could be warranted if the estimated useful life of
6 the assets changes or the level of asset additions or retirements changes the group's
7 average characteristics. For example, if the distribution system conversion program
8 resulted in an unusual volume of assets being retired before their expected useful
9 life, the depreciation rate on the remaining assets could be increased to ensure any
10 undepreciated balances were depreciated and recovered over future periods. This
11 impact could be offset by new assets added to the group which may have a longer
12 useful life (which would lower the depreciation rate).

13

14 **Q52. What would cause assets to be stranded?**

15 A52. Assets might be considered stranded if they are retired early and there are not
16 enough assets remaining in the pool to which an increased depreciation rate can be
17 applied. This could occur with large individual assets, especially when the assets
18 are not being replaced. For example, coal generation assets may be retired without
19 being replaced by new coal assets. Instead, they may be replaced with renewable
20 generation assets that are in a different plant account (asset pool). In this example,
21 there is no direct method to recover the undepreciated balance of the coal assets via
22 depreciation expense, and other recovery options must be used (such as regulatory
23 asset treatment or securitization).

24

Line
No.

1 **Q53. Do you agree with MNC Witness Jester that the Company's distribution assets**
2 **will be stranded as a result of the 4.8kV conversion project?**

3 A53. No. As described by Company Witness Stowe in his direct testimony, the
4 distribution assets being replaced include substation equipment, pole top
5 equipment, poles, wires and transformers. All of these assets are included in plant
6 accounts that are depreciated using the group method. While the voltage and design
7 of the new equipment will be different from the existing assets, the replacement
8 assets will be recorded to the same plant accounts as the old equipment. This will
9 allow for the depreciation rate on those accounts to be updated, if needed, to absorb
10 any undepreciated balances related to the retired assets.

11

12 **Q54. Is MNC Witness Jester's proposed accounting treatment appropriate?**

13 A54. No. As outlined in the USoA Electric Plant Instructions 10. B (2), the correct
14 accounting for retired assets is to credit plant in service and debit accumulated
15 depreciation for the original cost of the asset. This treatment applies whether or not
16 an individual retirement unit is fully depreciated. Since the assets being retired are
17 included in plant accounts that are recovered via group depreciation rates, deferred
18 asset accounting and securitization is not necessary or appropriate, and the
19 Commission should reject Witness Jester's proposal.

20

21 **Q55. Does this conclude your rebuttal testimony?**

22 A55. 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.)

SHERRI L. WISNIEWSKI

DTE ELECTRIC COMPANY
REBUTTAL 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. Did you file direct testimony in this proceeding on behalf of DTE Electric**
7 **Company (DTE Electric or Company)?**

8 A2. Yes.

9

10 **Q3. What is the purpose of your rebuttal testimony?**

11 A3. The purpose of my testimony is to:

- 12 • Rebut the property tax expense adjustment proposed by Attorney General
13 (AG) Witness Coppola. If capital disallowances are ordered by the
14 Commission, the methodology used by Witness Coppola to adjust property
15 tax expense is inaccurate.
- 16 • Rebut the property tax expense adjustments proposed by Association of
17 Businesses Advocating Tariff Equity (ABATE) Witnesses York and
18 Fitzhenry. If capital disallowances are ordered by the Commission, the
19 methodology used by ABATE Witnesses York and Fitzhenry to adjust
20 property tax expense is inaccurate.
- 21 • Propose a methodology for adjusting property tax expense if capital
22 disallowances are ordered by the Commission.

**Line
No.**

- 1 • Rebut AG Witness Coppola's assertion that the Company's calculation of
2 Taxes Payable is seriously flawed. The methodology the Company used to
3 calculate Taxes Payable is reasonable.

4 The purpose of my testimony is not to discuss the reasonableness of any capital
5 adjustments proposed by the Staff or any intervenors, as that is being addressed in
6 the rebuttal testimony of other Company witnesses. The absence of a discussion of
7 other matters in my rebuttal testimony should not be taken as an indication that I
8 agree with other aspects of any Staff or intervenor testimony.

9

10 **Q4. Are you sponsoring any rebuttal exhibits?**

11 A4. No.

12

13 *Rebuttal of the Property Tax Expense adjustment proposed by AG Witness Coppola*

14 **Q5. What property tax expense adjustment did Witness Coppola propose?**

15 A5. On page 152, lines 4 through 10 of Witness Coppola's testimony, Witness Coppola
16 is recommending a reduction in property tax expense for the projected test year of
17 \$9 million as calculated on Exhibit AG-20. The methodology Witness Coppola is
18 using to calculate this adjustment is to take the AG's proposed capital expenditure
19 reductions for 2025 and prior years and multiply this by 96%, 50%, and a millage
20 rate of 56.5.

21

22 **Q6. Do you agree with the methodology Witness Coppola is using to calculate the**
23 **property tax expense adjustment on proposed capital expenditure reductions?**

24 A6. No. This methodology is inappropriate because it fails to consider the following
25 aspects of the property tax expense calculation:

**Line
No.**

- 1 • Not all capital expenditures are subject to property tax in the same way. Plant
2 additions and changes in construction work in progress (CWIP) are taxed
3 differently from each other, and removal costs are not subject to property tax
4 at all. Witness Coppola's methodology does not distinguish those components
5 of the AG's proposed capital expenditure reductions so that property taxes on
6 each component can be calculated correctly.
- 7 • The Company treated capital expenditures related to nuclear generation as
8 nontaxable expenditures in this filing. Witness Coppola's methodology does
9 not exclude these components of the proposed capital expenditure reductions
10 from the calculation of the property tax expense adjustment.
- 11 • As discussed in my direct testimony (page 13, lines 2 through 6), the
12 Company expenses its property tax liability over a two-year period, with the
13 total liability of each year being expensed 39% the current year and 61% the
14 subsequent year. Therefore, if there is a change in the property tax liability
15 in any given year, property tax expense for that same year will change by only
16 39% of that change in the property tax liability. For example, if the 2026
17 property tax liability is reduced by \$100,000, 2026 property tax expense is
18 reduced by only \$39,000 (39% of \$100,000). Witness Coppola's
19 methodology ignores this step of expensing the property tax liability over a
20 two-year period.
- 21 By not taking these factors into consideration, Witness Coppola's methodology
22 results in a significant overstatement of the property tax expense adjustment on
23 proposed capital expenditure reductions. Accordingly, his methodology should not
24 be adopted.

Line
No.

1 Rebuttal of the Property Tax Expense adjustments proposed by ABATE Witnesses York
2 and Fitzhenry

3 **Q7. What property tax expense adjustment did Witness York propose?**

4 A7. On page 30 of Witness York's testimony, Witness York describes a reduction in
5 revenue deficiency of \$48.4 million related to proposed adjustments to capital
6 expenditures and states that this includes the estimated impacts to depreciation
7 expense and property taxes. Nowhere in her testimony or exhibits does Witness
8 York indicate the amount of the property tax adjustment or explain the
9 methodology she is using to calculate the adjustment. However, within Witness
10 York's workpaper, Table JAY-5 appears to include a proposed reduction in
11 property tax expense of \$7.4 million and a formula that appears to be calculating
12 this proposed property tax adjustment by dividing proposed capital expenditure
13 adjustments by 2 and multiplying this by 1.2% and 1.8% for generation and
14 distribution capital, respectively.

15

16 **Q8. What property tax expense adjustment did Witness Fitzhenry propose?**

17 A8. On page 18 of Witness Fitzhenry's testimony, Witness Fitzhenry describes a
18 reduction in revenue deficiency of \$5.6 million. Nowhere in his testimony does
19 Witness Fitzhenry state that this includes an adjustment to property tax expense,
20 nor does he explain why he is adjusting property tax expense or the methodology
21 he is using to calculate a property tax adjustment. However, Witness Fitzhenry's
22 workpaper for the Revenue Requirement Impact does appear to show that the \$5.6
23 million includes a proposed property tax adjustment of \$0.865 million. This
24 workpaper also includes a formula that appears to be calculating this proposed

**Line
No.**

1 property tax adjustment by dividing proposed capital expenditure adjustments by 2
2 and multiplying this by 1.8%.

3

4 **Q9. Do you agree with the methodology ABATE Witnesses York and Fitzhenry**
5 **are using to calculate their proposed property tax expense adjustments?**

6 A9. No. While Witnesses York and Fitzhenry do not explain their proposed property
7 tax adjustments, it appears they are attempting to adjust property tax expense
8 related to their capital expenditure adjustments. Their respective methodologies
9 bear no resemblance to how the Company calculated property tax expense in this
10 case, which is described in my testimony beginning on page 8, line 13, and
11 continuing through page 14, line 2.

12

13 *Proposed Methodology for adjusting Property Tax Expense on Capital Disallowances*

14 **Q10. Did Staff Witness Hecht propose a property tax expense adjustment on**
15 **proposed capital disallowances?**

16 A10. Yes. On page 6, lines 16 through 18 of Staff Witness Hecht's testimony, Witness
17 Hecht proposes a reduction in property tax expense for the projected test year of
18 \$1.152 million, which is based on the Staff's adjustments to the Company's capital
19 expenditures. This is also illustrated on page 4, Figure 1, of Witness Hecht's
20 testimony, and it is calculated in WP-JJH-1.

21

22 **Q11. Is the methodology Staff Witness Hecht uses to calculate the proposed**
23 **property tax expense adjustment on proposed capital disallowances similar to**
24 **the methodology the Company utilized to calculate property tax expense in**
25 **this case?**

**Line
No.**

- 1 A11. Staff Witness Hecht’s methodology is similar to the methodology the Company
2 utilized to calculate property tax expense in this case by taking the following factors
3 into consideration as they are applicable:
- 4 • Capital adjustments on nontaxable expenditures (i.e., steam power
5 generation, nuclear generation, and IT) are excluded.
 - 6 • Taxable capital adjustments impact the property tax liability the year after
7 they are incurred.
 - 8 • First year STC multiplier of 96% is applied to capital adjustments related to
9 plant additions to calculate true cash value.
 - 10 • True cash value is multiplied by 50% to calculate taxable value.
 - 11 • Taxable value is multiplied by the estimated millage rate of 56.5 to calculate
12 the change in the property tax liability.
 - 13 • Calendar year property tax expense is adjusted by 39% of the change in the
14 property tax liability in year 1 to reflect the Company’s two-year expensing
15 methodology.
- 16
- 17 **Q12. Are any elements of Staff Witness Hecht’s methodology to calculate the**
18 **proposed property tax expense adjustment on proposed capital disallowances**
19 **inconsistent with the methodology the Company utilized to calculate property**
20 **tax expense in this case?**
- 21 A12. Yes. Capital adjustments for components of CWIP are not separately identified.
22 As discussed by Company Witness Vangilder in his rebuttal testimony, the
23 “Infrastructure and Modernization – Lack of Detail” adjustment made on row 11 of
24 WP-JJH-1 does not properly distinguish what components of this adjustment are in
25 CWIP and apply the first year STC multiplier of 50% that is applicable to CWIP.

Line
No.

1

2 **Q13. If capital disallowances are ordered by the Commission, what methodology**
3 **should be used to calculate the corresponding adjustment to property tax**
4 **expense in this case?**

5 A13. If capital disallowances are ordered by the Commission, Staff Witness Hecht's
6 methodology, modified as described in Company Witness Vangilder's rebuttal
7 testimony, is reasonable and should be used to calculate the corresponding
8 adjustment to property tax expense.

9

10 Rebuttal of AG Witness Coppola's assertion that the Company's calculation of Taxes
11 Payable is seriously flawed.

12 **Q14. What taxes payable adjustment did Witness Coppola propose?**

13 A14. On page 69 of Witness Coppola's testimony, Witness Coppola makes the assertion
14 that the Company's calculation of Taxes Payable is seriously flawed and, as a result,
15 recommends that the Commission utilize the historic balance of Taxes Payable of
16 \$11.9 million for the projected test year.

17

18 **Q15. Do you agree with Witness Coppola's assertion that the Company's**
19 **calculation of Taxes Payable is seriously flawed?**

20 A15. No. The Company's calculation of the projected test year balance of \$2.4 million
21 for Taxes Payable is reasonable. The Company's calculation of Taxes Payable
22 starts with the historic balance and makes changes that are driven by detailed
23 calculations of current income tax expense that utilize test-period data and
24 assumptions, which is consistent with generally accepted accounting principles.
25 These are discussed in my direct testimony and illustrated in my exhibits as follows:

**Line
No.**

- 1 • Current Federal Income Tax (FIT) expense is described in my direct
- 2 testimony on page 15, lines 20 and 21, and illustrated on Exhibit A-13,
- 3 Schedule C8.
- 4 • Current Michigan Corporate Income Tax (MCIT) expense is described in my
- 5 direct testimony on page 16, lines 15 through 17, and illustrated on Exhibit
- 6 A-13, Schedule C9.
- 7 • Current municipal income tax expense is described in my direct testimony on
- 8 page 17, lines 4 and 5, and illustrated on Exhibit A-13, Schedule C10.

9

10 **Q16. Does this complete your rebuttal testimony?**

11 A16. 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

REBUTTAL TESTIMONY

OF

AARON WILLIS

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF AARON WILLIS

Line
No.

1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed?**

3 A1. My name is Aaron Willis. My business address is One Energy Plaza, Detroit,
4 Michigan 48226. I am employed by DTE Energy Corporate Services, LLC, a
5 subsidiary of DTE Energy Company as Director, Regulatory Affairs.

6

7 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
8 **Company (DTE Electric or Company)?**

9 A2. Yes.

10

11 **Q3. Are you sponsoring any rebuttal exhibits?**

12 A3. Yes. I am sponsoring the following exhibits:

<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
A-59	AAA1	Staff IRM ROR Analysis Discovery

15

16 **Purpose of Testimony**

17 **Q4. What is the purpose of your rebuttal testimony?**

18 A4. The purpose of my rebuttal testimony is to respond to certain positions taken by
19 Witnesses Boutet, Shi, Evans, Revere, Krause, and Isakson on behalf of Michigan
20 Public Service Commission (MPSC or Commission) Staff (Staff); Witness Jester
21 on behalf of the Michigan Environmental Council (MEC), Natural Resource
22 Defense Council (NRDC), and Citizens Utility Board of Michigan (CUB)
23 (collectively MNC); Witness Nichols on behalf of Soulardarity and We Want
24 Green, Too (collectively DAAO); Witness Dauphinais on behalf of the Association
25 of Businesses Advocating Tariff Equity (ABATE); Witnesses Alvarez and

Line
No.

1 Stephens on behalf of the Attorney General (AG), MEC, and NRDC (collectively
2 AG-MN); Witness Lyon on behalf of Walmart; and Witnesses Kenworthy and
3 Volkmann on behalf of the Clean Energy Organizations (CEO).

4
5 Specifically, my rebuttal testimony will provide responses across the following
6 topics:

- 7 1. The Company's proposed Infrastructure Recovery Mechanism (IRM) and
8 the recommendations of Staff Witnesses Evans, Boutet, and Shi, AG-MN
9 Witnesses Alvarez and Stephens, ABATE Witness Dauphinais, Walmart
10 Witness Lyon, and CEO Witness Volkmann
- 11 2. Staff Witness Revere's proposal regarding Uncollectable Expense (UCX)
12 and the base Power Supply Cost Recovery (PSCR) in the rate case
- 13 3. The Commission's approved transition of customers from Rate Schedule
14 D1.6 to Rate Schedule D1.11 and associated recommendations from CEO
15 Witness Kenworthy and DAAO Witness Nichols
- 16 4. MNC Witness Jester's proposal regarding seasonal distribution rates
- 17 5. Staff Witness Krause's proposal that the Company propose a direct current
18 fast charger (DCFC) rate for electric vehicle (EV) charging in its next rate
19 case
- 20 6. Walmart Witness Lyon's proposal related to a DCFC rate stakeholder
21 meeting
- 22 7. Staff Witness Isakson's proposal regarding residential minimum service
23 tariff language

Line
No.

1 **Distribution Infrastructure Recovery Mechanism (IRM)**

2 **Q5. What Staff and intervenor positions related to the Company's Distribution**
3 **IRM proposals are you addressing?**

4 A5. There are five parties I will address related to the Company's IRM proposals:

- 5 • Staff Witness Evans, Shi, and Boutet's recommendations to adopt in part
6 the Company's proposed extension and expansion of the IRM for 2026 and
7 2027-2029, and to utilize a rate of return below the ordered pretax rate of
8 return but no lower than the short-term debt rate for the 2027-2029
9 investments
- 10 • AG-MN Witnesses Alvarez and Stephens' proposal to terminate the IRM
11 as of December 31, 2026
- 12 • ABATE Witness Dauphinais' recommendation to reject the Company's
13 proposed 2026 alternative IRM, proposed 2028 and 2029 IRM, and
14 proposed inclusion of Pole and Pole Top Maintenance and Modernization
15 (PTMM) in the IRM, and otherwise limit 2027 investments to the
16 Company's alternative proposal
- 17 • CEO Witness Volkmann's recommendation that the Company propose
18 IRM process modifications in rebuttal
- 19 • Walmart Witness Lyon's recommendations related to the timing of rate case
20 filings and IRM approvals

21

22 **Q6. Can you summarize Staff Witness Boutet's recommendation with respect to**
23 **the Company's proposed alternative for the 2026 IRM?**

Line
No.

1 A6. Yes. In his direct testimony, Staff Witness Boutet explains that Staff supports the
2 inclusion of \$200M of the Company's proposed 2026 PTMM investment in the
3 2026 IRM instead of base rates. He explains:

4
5 "Staff acknowledges the importance of funding the PTMM program given the
6 current age and condition of poles and pole top infrastructure on the Company's
7 system. Therefore, Staff is formally supporting the Company request to
8 transition \$200 million in the 2026 test year for the PTMM program into the
9 Company's Distribution Infrastructure Recovery Mechanism (IRM). IRM
10 inclusion ensures that dollars assigned to a specific work program will be spent
11 on that specific program or refunded to customers if not spent. Staff finds that
12 the work included in the PTMM program is critical to improving the
13 Company's reliability performance in the near future, and it would be
14 reasonable and prudent to ensure that every dollar possible is spent responsibly
15 on this program for the good of customers."¹

16

17 **Q7. Does the Company agree with Staff Witness Boutet's recommendation to move**
18 **the Company's proposed 2026 PTMM investment from base rates to the IRM?**

19 A7. Yes. The Company is supportive of this recommendation and the acknowledgment
20 from Witness Boutet of the customer benefits associated with the IRM.

21

22 **Q8. Can you please summarize Staff Witness Shi's recommendation with respect**
23 **to the Company's proposed 2026 distribution automation spend?**

¹ Staff Witness Boutet, Pg 11

Line
No.

1 A8. Yes. Witness Shi proposes to disallow approximately \$97.5M in 2026 distribution
2 automation spend. This disallowance is based on the Company's 2025 pace of
3 investment in the program, with Witness Shi saying "Staff recommends aligning
4 the program's budget forecast with DTE's demonstrated spending capability"² and
5 continuing "Staff has reviewed DTE's actual expenditures for the first four months
6 of 2025...and **recommends a [2026] disallowance of \$97,477,223 from the**
7 **requested amount of \$115,625,000.**"³ (emphasis added).
8

9 **Q9. Does the Company offer an alternative to Witness Shi's recommendation?**

10 A9. Yes. Company Witness Rademacher addresses the proposed linear monthly
11 spending analysis. Given that the recommended disallowance of \$97.5M in 2026 is
12 premised and calculated on Staff's perspective that the Company may not succeed
13 in making all of the planned investments, recovery through the Infrastructure
14 Recovery Mechanism instead of base rates provides a compelling alternative. As
15 described in my direct testimony, one of the key benefits of the IRM is that if the
16 approved capital is not invested, then associated revenue will be returned to
17 customers. Said differently, under IRM recovery, if the Staff's expected Company
18 investment levels in 2026 were to materialize, the IRM would require that a refund
19 be made to customers. For Staff's specific concern, the IRM is an effective
20 mitigation. Therefore, the Company recommends that, consistent with its 2026
21 alternative IRM proposal in my direct testimony, if the Commission agrees with
22 Staff regarding the investment cadence it should include the 2026 distribution
23 automation program within the IRM as an alternative to outright disallowance.

² Staff Witness Shi, Pg 10

³ Staff Witness Shi, Pg 10-11

Line
No.

1 **Q10. Can you summarize Staff Witness Evans’ recommendations with respect to**
2 **the Company’s proposed 2027 – 2029 IRM investment?**

3 A10. Yes. Staff Witness Evans supports “approving the three-year extension of 2027-
4 2029⁴” with the following amounts and commentary for each IRM investment area:

5

6 • **Subtransmission Redesign and Rebuild** – “Staff recommends the alternative
7 amounts of \$52.5 million, \$57.5 million, and \$60.0 million, as shown in Table
8 3 below, because the Company needs to provide a plan and more data as
9 directed by the June 12, 2025 order in Case No. U-21305.⁵” The Table 3
10 referred to by Witness Evans is found on Page 11 of his testimony and reflects
11 the Company’s alternative proposal initially included in my direct testimony.

12

13 • **Breakers, URD Replacement, System Cable** – “Staff supports the Breaker
14 replacement, URD replacement, and System Cable amounts shown in Table 2
15 above.⁶” The Table 2 referred to by Witness Evans is found on Page 9 of his
16 testimony and reflects the Company’s primary IRM proposal included in my
17 direct testimony.

18

19 • **Distribution Automation** – “Staff recommends approving the amounts in
20 Table 2, but the 2028 and 2029 amounts are contingent on meeting the
21 requirements of the June 12, 2025 order in Case No. U-21305, which stated on
22 page 36:

⁴ Staff Witness Evans, Pg 11

⁵ Ibid

⁶ Ibid

Line
No.

1 *'The Commission finds that safety, reliability, and value are important aspects*
2 *of electric service, and there is a need for DTE Electric to prioritize safety on*
3 *its 4.8kV system, which includes installation of Viper reclosers. However, the*
4 *Commission finds that tree trimming is also essential to safe, reliable service*
5 *and that other alternatives may also be reasonable and economical. Thus, the*
6 *Commission requests that DTE Electric submit, with its next DSP, the*
7 *company's strategy for improving safety and reliability to its 4.8kV system prior*
8 *to conversion. The plan should also describe planned timing for Viper recloser*
9 *installation on the 4.8kV system for safety at the substation exits and for*
10 *reliability beyond the substation exits and include an assessment that compares*
11 *tree trimming and other alternative measures for providing safe, reliable*
12 *service so that the prioritization of expenditures to improve reliability cost*
13 *effectively may be more clearly discerned.'*
14

- 15 • **PTMM** – “Staff supports adding PTMM to the IRM and supports the proposed
16 investment amounts shown in Table 2.”⁷
17

18 **Q11. What is the Staff's overall recommendation related to IRM investment levels?**

19 A11. In summary, Staff proposes a 2027 – 2029 IRM which reflects the Company's
20 primary proposal for PTMM, Automation, Breakers, URD, and System Cable, and
21 the Company's alternative proposal for Subtransmission. For ease of review, I am
22 reflecting those adjustments, which the Company supports, below in Table 1.

⁷ Staff Witness Evans, Pg 12

Line
No.

1

Table 1 – Staff Proposed IRM Investment Levels (\$M)

2

	Existing IRM Years			Future IRM Years		
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
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 ⁸	26.4	24.4	24.4	165	250	320
PTMM	n/a	n/a	200	263.4	376.8	482.6
Total	61.9	290.1	304.3	535.9	756.3	948.6

3

4 **Q12. What is the Company’s response to Witness Evans’ contingent support for**
5 **2028 and 2029 distribution automation IRM investments?**

6 A12. Witness Evans supports the Company’s proposed IRM distribution automation
7 investment contingent on “meeting the requirements of the June 12, 2025 order in
8 Case No. U-21305”. These requirements, captured above, relate to providing an
9 assessment comparing automation investments relative to other approaches for
10 improving reliability as well as the timing of automation investments to be made at
11 various points in the system. As a general matter, the Company’s filings are
12 consistent with the relevant direction issued by the Commission, and the

⁸ Authorized as “4.8 kV Circuit Automation” for IRM Years 2024 and 2025.

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1 Company's next Distribution System Plan will similarly be filed consistent with
2 prior orders.

3

4 **Q13. Can you summarize Staff Witness Evans' recommendation regarding the**
5 **appropriate rate of return (ROR) for the IRM?**

6 A13. Yes. In his direct testimony, Staff Witness Evans explains:

7 "Staff also recommends that for 2027-2029, the rate of return associated with
8 the IRM surcharge should be lower than the pretax rate of return (ROR) as
9 ordered in this instant case, but no lower than the short-term debt rate (STD)
10 ordered in the instant case. Once these investments are found to be prudent and
11 reasonable for inclusion in base rates in a future rate case Staff intends for the
12 normal ROR to apply."⁹

13

14 **Q14. What is Witness Evans' basis for the proposed lower ROR for the IRM?**

15 A14. Witness Evans' primary justification for the lower ROR proposal is based on
16 differences in the Company's investment across decades. First, he notes what he
17 terms as "underinvestment" in 2013, 2014, and 2016, and compares them to the
18 Company's proposed spending in 2025-2028. He then acknowledges, in reference
19 to 2025-2028 investment, that "...while Staff is not saying the projections for 2025-
20 2028 are the correct amounts, they are probably closer in magnitude to what the
21 system requires than the amounts that were spent a decade or more earlier". He
22 simply concludes "[d]ue to this previous underinvestment, Staff believes that a
23 lower rate of return should be built into the IRM surcharge."¹⁰

⁹ Staff Witness Evans, Pg 12

¹⁰ Staff Witness Evans, Pg 14

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1 The Company has no reason to doubt the veracity of the capital numbers cited by
2 Witness Evans, but the conclusion he draws from those numbers is unsupported.
3 Staff acknowledged on discovery (included as Company Exhibit A-59 Schedule
4 AAA1) that beyond Witness Evans' statements regarding increased capital
5 investment in his testimony, no analysis was conducted to demonstrate either 1)
6 why increasing investment levels should lead to a lower ROR or 2) that Witness
7 Evans' proposed range between short-term debt and the Company's standard ROR
8 is appropriate.

9

10 **Q15. Does the Company agree with Staff's recommendation for a lower ROR on**
11 **IRM investments?**

12 A15. No. As described by Company Witness Lepczyk in more detail, the Company's
13 ability to raise capital (and the cost of that capital) for investments is not predicated
14 on whether these investments are recovered initially through base rates, or first
15 through the IRM and then base rates. Company Witness Lepczyk recommends that
16 the Company's standard rate of return, which is applied to all capital investments,
17 be similarly applied to IRM investments.

18

19 In this case, as described in the direct testimony of Company Witness Vangilder¹¹,
20 the Company updated the rate of return assumption for future years of the IRM to
21 align it with the Company's overall rate of return, instead of the previously
22 approved weighted cost of permanent capital. Such a change is consistent with the
23 Commission's perspective in the January 23, 2025, Order in Case No. U-21534
24 which noted that there should not be "a higher rate of return on IRM than the rate

¹¹ Direct testimony of Company Witness Vangilder, Pg 19

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1 of return that would apply to non-IRM investments in its distribution
2 infrastructure¹²”. The Company’s position in this case brings the IRM rate of return
3 into alignment with “non-IRM investments in its distribution system”. Given
4 Witness Evans’ support for full ROR when the IRM investments are moved to base
5 rates, consistency would suggest that the full ROR be applied to the IRM as well.

6

7 Going forward, an approval of IRM capital investment without a rate of return
8 consistent with all other capital investments made by the Company may cause the
9 Company to reevaluate the role of the IRM. As described by Witness Lepczyk, it
10 would be difficult for the Company to finance these investments at a reduced rate
11 of return.

12

13 In summary, the Company recommends the Commission reject the Staff IRM ROR
14 proposal.

15

16 **Q16. Can you summarize AG-MN Witnesses Alvarez and Stephens’**
17 **recommendations with respect to the Company’s proposed extension of the**
18 **IRM?**

19 A16. Yes. AG-MN Witness Alvarez offers various observations with respect to the
20 Company’s proposed IRM and ultimately recommends the Commission “terminate
21 the IRM as of December 31, 2026”.

22

23 Witness Alvarez describes the first of the “unintended consequences” which he
24 asserts result from “future test years and rider cost recovery”:

¹² January 23 Order Pg 303

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1 “The testimony and exhibits DTE provides with its rate cases constitute
2 investment plans, and intervenors have an opportunity to challenge DTE’s
3 investment plans in those rate cases. But despite the apparent logic of advance
4 regulatory review of utility investment plans, it is precisely this advance review
5 that paradoxically creates the most significant unintended consequence: the
6 practical elimination of a regulator’s ability to disallow costs from customer
7 recovery.”¹³ The testimony continues “no matter how strong the evidence the
8 intervenor presents that the project or program was imprudent, the regulator
9 will be practically unable to issue an imprudence finding (other than in cases of
10 gross negligence or malfeasance). This is because the projects or programs were
11 part of an investment plan the regulator already approved.”¹⁴

12

13 The second unintended consequence “theorized” by Witness Alvarez is that of
14 “moral hazards” in ratemaking associated with future test years and rider cost
15 recovery. He asserts:

16 “The fact that making imprudent investments can result in a financial penalty
17 under traditional ratemaking, while proposing potentially imprudent projects or
18 programs in investment plans incurs no financial penalty, is crucial. It is an
19 example of what economists call *moral hazard*...[t]he implications of moral
20 hazard in ratemaking are profound. It means that utilities will propose
21 questionable investments in an investment plan that it would never actually
22 make under traditional ratemaking due to cost disallowance risk.”¹⁵

¹³ AG-MN Witness Alvarez Pg 53

¹⁴ AG-MN Witness Alvarez Pg 54

¹⁵ AG-MN Witness Alvarez Pg 55

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1 Witness Alvarez goes on to describe the perceived change in risk profile between
2 the Company and customers. He asserts:

3 “When cost disallowance risk is practically eliminated, utilities are more likely
4 to include inappropriate, or premature, or cost-ineffective, or inadequately
5 supported projects and programs in their investment plans...while shareholders
6 bear the risk of imprudent investments under traditional ratemaking, customers
7 pay the price for any inappropriate, or premature, or cost ineffective, or
8 inadequately supported projects and programs approved as part of future test
9 year and rider investment plans...I deem this... as the most significant
10 unintended consequence.”¹⁶

11

12 Witness Alvarez closes in summary with the assertion that:

13 “Given future test years and DTE’s frequent rate cases, and given the ability of
14 these to reduce regulatory lag, I fail to perceive the need for an additional
15 mechanism – DTE’s IRM – to reduce regulatory lag... In recognition of all
16 these observations, I recommend the Commission terminate the IRM as of
17 December 31, 2026”¹⁷

18

19 Additional testimony related to IRM capital programs offered by AG-MN
20 Witnesses Alvarez and Stephens, including Witness Stephen’s proposed blanket
21 disallowance of PTMM in the IRM, is addressed by the appropriate Company
22 witnesses, and Company Witness Lepczyk explains why securitization for new
23 distribution investments, including PTMM, is inappropriate.

¹⁶ AG-MN Witness Alvarez Pg 56

¹⁷ AG-MN Witness Alvarez Pg 59

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1 **Q17. Does the Company agree with Witness Alvarez's recommendation to**
2 **terminate the IRM at the end of 2026?**

3 A17. No. Witness Alvarez's unintended consequences are essentially based on what is
4 perceived as a lesser level of review for IRM investments compared to those
5 proposed in rate cases. In reality, the IRM approved by the Commission has greater
6 transparency and opportunity for stakeholder input than a general rate case does.
7 Stakeholders have the opportunity to:

- 8 • Debate the prudence of programs and investments in rate cases, as AG-MN
9 and other parties do in this case.
- 10 • Review a project line-item plan before the investments are made, with an
11 opportunity to provide feedback electronically and in a stakeholder forum.
- 12 • Participate in a contested reconciliation of those investments in the year
13 following (for example, testimony was filed on September 9, 2025 for the
14 ongoing 2024 IRM reconciliation in Case No. U-21845, including
15 testimony from parties Witness Alvarez represents in this case in the form
16 of Witness Stephens filing testimony on behalf of the AG, MEC, and CUB).

17 The Company further proposed in direct testimony to expand opportunity for
18 stakeholder input by adding both 1) a technical conference in 2025 with a view
19 towards project prioritization and selection methods for the 2027-2029 IRM plans,
20 and 2) earlier engagement during Plan development to ensure an opportunity for
21 stakeholder input to the Plan *before* its publication.

22

23 The additional concerns voiced by Witness Alvarez in this case are predicated on a
24 philosophical opposition to rider cost recovery and various consequences that are
25 alleged to stem from rider cost recovery. Witness Alvarez offers similar testimony

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1 to this case as was filed in the Company's prior electric rate case, Case No. U-
2 21534. For example, in that case Witness Alvarez said "Rider cost recovery shifts
3 capital spending risk from shareholders to customers, shifts prudence
4 responsibilities from utilities to intervenors, and introduces moral hazard into utility
5 distribution grid investment plan development. I discussed these unintended
6 consequences at length in my testimony in U-21297..."¹⁸ The Commission's final
7 orders in both Case Nos. U-21534 and U-21297 appropriately declined to adopt
8 Witness Alvarez's recommendations, and I recommend the Commission do the
9 same in this case.

10

11 I also recommend the Commission reject Witness Stephens' recommendations
12 related to distribution automation, PTMM, and subtransmission investment
13 disallowances (responded to in detail by the Company's capital program witnesses)
14 and approve, at a minimum, the Staff's proposed IRM investment levels for 2026
15 – 2029.

16

17 **Q18. Can you summarize ABATE Witness Dauphinais' recommendations to limit**
18 **the Company's proposed IRM investments?**

19 A18. Yes. ABATE Witness Dauphinais recommends four changes to the Company's
20 proposal:

- 21 • Reject the 2026 alternative option
- 22 • Reject extensions to 2028 and 2029
- 23 • Reject the addition of PTMM to the IRM generally

¹⁸ Alvarez direct testimony, Case No. U-21534, Pg 29

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- 1 • Limit 2027 investments to programs previously approved (no PTMM) in
2 amounts no more than the Company’s proposed alternative option

3

4 Witness Dauphinais outlines a series of considerations in support of the
5 recommendations:

6 “(i) there is in fact an urgent and undisputed need for each included investment
7 and each such investment has been robustly shown to be the most cost effective
8 way to address the need, (ii) the years authorized for the Distribution IRM not
9 go beyond the projected test year of the utility any more than necessary, and
10 (iii) the defined categories are not defined overly wide such that the utility is
11 able to avoid a greatly needed authorized investment in a cost category by
12 making up for it with investment in the same category that has a lower degree
13 of need.”¹⁹

14

15 Witness Dauphinais identifies specific concerns with “single issue ratemaking²⁰”,
16 the growth of the IRM which would cause the Company to “unreasonably, and
17 greatly, expand its distribution investments at the expense of its ratepayers,
18 regardless of the need and cost effectiveness of those investments”, and with respect
19 specifically to the alternative option for 2026 argues it is “essentially a re-litigation
20 of the outcome of...U-21534.”²¹

21

22 **Q19. Does the Company agree with Witness Dauphinais’ recommendations to limit**
23 **the duration and programmatic scope of the IRM?**

¹⁹ ABATE Witness Dauphinais Pg 22

²⁰ ABATE Witness Dauphinais Pg 23

²¹ ABATE Witness Dauphinais Pg 24

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- 1 A19. No. Below I address each of Witness Dauphinais' specific concerns.
- 2 • *Single issue ratemaking* – The Commission has found the IRM appropriate
- 3 in multiple cases and has not adopted the view that it constitutes single issue
- 4 ratemaking, including most recently in its January 2025 Order in Case No.
- 5 U-21534. Moreover, the IRM is proposed, litigated, and approved in a
- 6 contested general rate case such as the instant case – there is no single issue
- 7 ratemaking.
- 8 • *Investment expansion* – In my direct testimony in this case, I said “All else
- 9 equal, investments not proposed for recovery in the IRM would be proposed
- 10 for recovery in base rates as the Company's overall investment plans are
- 11 not contingent on IRM treatment – the IRM is one form of cost recovery
- 12 that brings with it an increased level of transparency and accountability²²”.
- 13 This remains true and the presence or absence of the IRM does not drive the
- 14 Company's need to invest; contrary to Witness Dauphinais' perspective,
- 15 any expansion of distribution investment is driven by reliability and other
- 16 outcomes sought as described by the Company's distribution investment
- 17 witnesses.
- 18 • *Relitigating U-21534* – the audit conducted in Case No. U-21305 was not
- 19 yet concluded during Case No. U-21534. One of the audit takeaways,
- 20 described by Company Witness Chiu, was the importance of the PTMM
- 21 program. The detailed discussion of PTMM in this case by Company
- 22 Witness Robinson, and its proposed inclusion in the IRM, is therefore
- 23 supported by new information.

²² Willis direct 19

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1 Based on the preceding discussion, I recommend the Commission reject the IRM
2 recommendations of ABATE Witness Dauphinais.

3

4 **Q20. Can you summarize CEO Witness Volkmann's recommendations to limit the**
5 **Company's proposed IRM investments?**

6 A20. Yes. CEO Witness Volkmann recommends "the Company, in its rebuttal
7 testimony, propose modifications to the IRM planning and reconciliation processes
8 to provide increased transparency/accountability for both the efficiency *and*
9 effectiveness of its proposed IRM investments²³". (emphasis original). Further,
10 Witness Volkmann's testimony acknowledges the role of the IRM processes,
11 saying "I agree that the IRM planning and reconciliation processes provide
12 accountability and transparency into the authorized investments."²⁴

13

14 CEO Witness Volkmann also asserts that future IRM spending is "locked in"²⁵
15 regardless of effectiveness, rhetorically questioning what would happen if
16 distribution automation, for example, is less effective than anticipated.

17

18 Witness Volkmann continues by saying "[o]ne possibility would be to use the IRM
19 reconciliation process not just to confirm the efficiency of IRM spending, but also
20 as a means to monitor IRM effectiveness. Over the last few cases, the CEO have
21 urged DTE to include more actual system data and outcomes in its reliability
22 modeling, GPM, and BCAs. The IRM reconciliation process is the next frontier of
23 that recommendation. The Commission, the Company, Staff and intervenors can

²³ CEO Witness Volkmann Pg 31

²⁴ CEO Witness Volkmann Pg 29

²⁵ CEO Witness Volkmann Pg 29

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1 use the IRM reconciliation process to adjust future IRM authorized spending based
2 on the effectiveness of different programs”²⁶. He then recommends the Company,
3 in rebuttal, propose changes to the reconciliation process.
4

5 **Q21. Do you agree with CEO Witness Volkmann?**

6 A21. No. While the Company agrees that the IRM processes provide additional
7 accountability and transparency into the authorized investments, and notes that
8 those features are among the key design characteristics that make the IRM an
9 important tool for addressing the Company’s needed distribution investments, the
10 Company does not agree with the balance of Witness Volkmann’s perspectives or
11 recommendations.
12

13 The Company does not agree that process changes related to defining investment
14 performance, and using those outcomes to alter future IRM recovery, are necessary.
15 As noted above, absent the IRM, the Company would propose similar investments
16 for inclusion in base rates – the IRM is a recovery mechanism of otherwise prudent
17 investments. The prudence of the programs, including their effectiveness, is an
18 important topic for the Distribution System Plan and is discussed by the Company’s
19 distribution capital witnesses in this case. Moreover, disallowing recovery for
20 prudent and approved investments is arguably retroactive ratemaking. Consistent
21 with the concept that the IRM is a recovery mechanism and not itself an investment
22 plan, any needed investments would otherwise be proposed through another
23 recovery mechanism (e.g. base rates). If the Commission approves capital for
24 recovery in rate base, and assuming the investment is made at the approved amount

²⁶ CEO Witness Volkmann Pg 30

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1 and timing, there is no basis for the Commission to retroactively adjust rate base
2 because the “effectiveness” of the investment was insufficient. Effectiveness tests
3 guide investment decisions; it would be inappropriate and improper to use them to
4 alter prior investment recovery.

5

6 In addition, as described by Company Witness Chiu’s direct testimony, the
7 Company’s overall distribution investment strategy is aligned with the audit
8 recommendations from Case No. U-21305.

9

10 **Q22. Regarding Witness Volkmann’s effectiveness test proposal, are there any**
11 **pending matters which tie the Company’s reliability performance to financial**
12 **outcomes?**

13 A22. Yes. The Company’s pending proposal in Case No. U-21909 regarding financial
14 incentives and disincentives for reliability performance includes seven key metrics
15 and targets consistent with the Commission’s Service Quality and Reliability
16 Standards. This proposal is the result of more than two years of discussion among
17 the Company, Commission Staff, and stakeholders (including the organizations
18 Witness Volkmann represents in this case) in Case No. U-21400. This is a far more
19 reasonable and effective approach to ensuring the success of the Company’s
20 investments. The proposal in Case No. U-21909 requires performance across the
21 totality of the Company’s investments and reliability efforts – it is neither
22 reasonable nor necessary to bifurcate the efficacy of just the Company’s IRM
23 investments when considering reliability improvements, nor is it reasonable to use
24 reliability outcomes to retroactively disallow investments. The Company’s

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1 proposal in Case No. U-21909 is a far more appropriate approach to managing
2 reliability performance. As such I recommend the Commission reject this proposal.

3

4 **Q23. Can you describe Walmart Witness Lyon’s recommendations regarding IRM**
5 **timing and process?**

6 A23. Yes. Walmart Witness Lyon recommends that the Commission should “require the
7 Company to file a base rate case at the earliest possible date when the assets can be
8 included in the Company’s test year²⁷” and that “the Commission should deny
9 recovery of any costs exceeding what was approved in the Company’s last rate case
10 for IRM plan year 2026, requiring the Company to recover these additional costs
11 through base rates instead²⁸”. Further, he recommends that “If the Commission
12 extends the IRM beyond 2026, it should evaluate whether increasing the scope to
13 include ever-increasing costs through a rider is necessary to ensure reliability, or if
14 such costs should be recovered through base rates as historically done to consider
15 all costs, benefits, and risks comprehensively.”²⁹

16

17 **Q24. Does the Company agree with Walmart Witness Lyon’s recommendations?**

18 A24. No. The Company has maintained its intent to propose the inclusion of IRM assets
19 in base rates in the first rate case following a reconciliation. The Company is
20 opposed to any recommendation that the Commission require the Company to file
21 a rate case on a specific cadence. While I am not an attorney and am not offering a
22 legal opinion, such a recommendation would in any event appear at odds with MCL
23 460.6a.

²⁷ Walmart Witness Lyon Pg 7

²⁸ Walmart Witness Lyon Pg 24

²⁹ Walmart Witness Lyon Pg 25

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1 Regarding the 2026 IRM, the Company's primary proposal is to include all such
2 investment in base rates in this proceeding. Recognizing the Commission may find
3 merit in alternatively approving a portion or all of that investment within the IRM,
4 the Company articulated that option as well, and either is acceptable to the
5 Company.

6

7 Turning to the role of IRM recovery compared to base rate recovery, the Company
8 understands that each has a role to play in cost recovery. However, the benefits of
9 the IRM described in my direct testimony, and the acknowledgement of those
10 benefits by various parties and the Commission, provides a strong basis to continue
11 utilizing the IRM for distribution investments going forward.

12

13 **Uncollectibles Expense (UCX) and Power Supply Cost Recovery (PSCR)**

14 **Q25. Can you summarize Staff Witness Revere's proposal regarding the projection**
15 **of UCX calculation?**

16 A25. Yes. Staff Witness Revere describes the Company's approach to forecasting
17 revenue upon which to base its UCX calculations. Specifically, he describes the use
18 of the forecasted 2026 PSCR Factor from the 2025 PSCR Plan (Case No. U-21594)
19 and the associated net system requirements assumption from that case as a basis for
20 calculating the PSCR factor revenue contribution to the UCX calculation. On this
21 topic, he says "Staff does not, however, agree with the use of the projected 2026
22 net system requirements from the PSCR plan case.... For this reason, I supplied
23 Staff witness Shannon Rueckert with Staff's projected power supply sales to use in

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1 the calculation of PSCR factor revenue to be included in Staff's projected
2 uncollectibles expense calculation"³⁰.

3

4 **Q26. Does the Company agree with Staff Witness Revere's adjustment to the UCX**
5 **revenue basis?**

6 A26. The recommendation to update the sales upon which to calculate the PSCR factor
7 revenue contribution is reasonable, and the Company does not object to such an
8 adjustment.

9

10 **Q27. Can you summarize Staff Witness Revere's proposal regarding the base PSCR**
11 **costs assumed in the rate case?**

12 A27. Yes. Staff's proposal is that "the Commission require the Company to propose
13 resetting the PSCR base in its next rate case" in order "to avoid the potential need
14 to make adjustments to the uncollectible expense calculation". The testimony
15 makes two observations in support of this recommendation.

16 • Role of the PSCR factor – "it is Staff's position that the PSCR factor should be
17 used to minimize over- and under-recoveries throughout the year due to
18 variations in revenues or costs compared to the plan."³¹

19 • Cost allocation – Staff notes that rate cases allocate PSCR costs on a
20 combination of demand and energy, while the PSCR factor is allocated on an
21 energy only basis, leading to what Witness Revere's testimony terms as "a
22 mismatch" between how costs are incurred versus recovered.

³⁰ Staff Witness Revere Pg 6-7

³¹ Staff Witness Revere Pg 7

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1 **Q28. How does the Company respond to this proposal?**

2 A28. The Company recognizes the challenges with accurately forecasting UCX in the
3 context of requests for rate relief; indeed Company Witness Sparks' revised direct
4 testimony in this case offered an updated method relative to prior cases in an effort
5 to simplify the underlying calculations and responding to feedback from prior
6 cases. While the Company remains open to additional discussions on approaches
7 to calculating the revenue basis for UCX calculations, it does not believe that a
8 rebasings of the PSCR assumed in rate cases is an appropriate way to do so.

9

10 Considering Staff's proposal to rebase the PSCR, I address the role of the PSCR
11 factor and cost allocation, and Company Witness Burgdorf describes the additional
12 testimonial and evidentiary burden that would be required of the Company and
13 intervenors if the Commission were to adopt Staff Witness Revere's
14 recommendation.

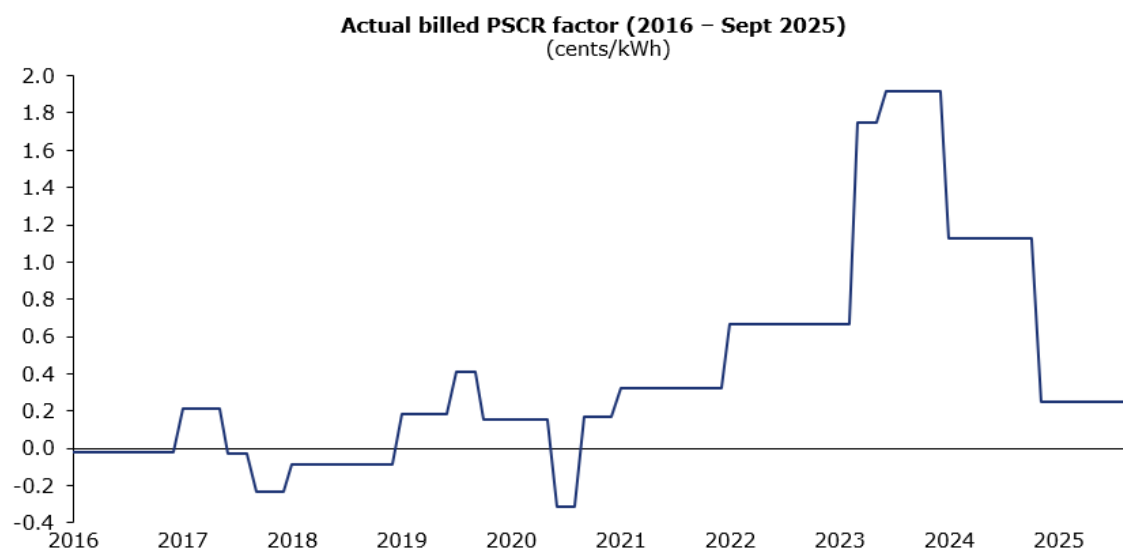
15

16 The Company acknowledges Staff's view that the PSCR factor should be a
17 mechanism by which to manage for over and under recovery. The factor has
18 historically served that role and continues to do so today. Considering the last
19 almost ten years, the billed factor has consistently remained within a relatively
20 narrow band around zero – the notable exception to this pattern is the trailing
21 COVID impacts and energy market upheaval in response to geopolitical events in
22 2022 – 2024. This is evident in Chart 1 below; outside of the exceptionally atypical
23 years of 2022 – 2024, the factor has been as low as (0.311) cents/kwh and has risen
24 to 0.41 cents/kWh. To date in 2025, the PSCR factor of 0.25 cents/kWh is lower
25 than it was parts of 2021 and 2019.

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1

Chart 1 – Billed PSCR Factor



2 Resetting the base would not appear to lead to a meaningfully more accurate
3 estimate of power supply expenses. In fact, the timing of such a rebase appears to
4 be the leading indicator of what rebasing would suggest for base power supply
5 expense (and in turn the factor). Had it been done in 2018, the base would
6 presumably have been lower and factor would have been consistently higher. On
7 the other hand, had it been reset in 2023 the Company would presumably be in a
8 persistent state of having a negative factor. Thus, the initial intent of the PSCR
9 factor remains applicable today, and it remains in a reasonable band around zero.

10

11 Regarding cost allocation, the Company offers two observations. The first is that
12 given the reasonably narrow band of movement around, or just slightly above, a
13 zero factor (again, with the exception of 2022-2024), puts and takes from cost
14 allocation are within a reasonable range as contemplated by the factor. The second
15 is that base PSCR cost recovery is already very heavily weighted to an energy

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1 allocation. While there is a demand component, which applies only to transmission
2 expense, the net difference is a reallocation of less than 1% of total PSCR cost.³²

3
4 In addition, the Commission has indicated an interest in reducing the scope and
5 volume of rate cases. Case No. U-21637 is one example of this, and while
6 comments and deliberations are ongoing in that matter, the intent to find
7 opportunities to streamline cases is evident. As Company Witness Burgdorf
8 describes, rebasing the PSCR would create a substantial additional burden within
9 the case for all parties.

10
11 Considering the foregoing testimony, I recommend the Commission does not adopt
12 the recommendation that the Company should be ordered to rebase the PSCR in its
13 next rate case.

14

15 **D1.6 to D1.11 Transition**

16 **Q29. Can you summarize DAAO Witness Nichols' recommendations regarding the**
17 **Company's plan to transition Rate Schedule D1.6 customers and the**
18 **associated studies?**

19 A29. Yes. DAAO Witness Nichols offers three recommendations related to the low-
20 income time of use transition:

21 "1. Require that DTE track low-income customers' bills after the transition to
22 Rate Schedule D1.11 and report this data in its next general rate case in such a
23 form that it will permit analysis of how many low-income customers
24 experienced decreased and increased bills and by how much.

³² \$~13M of total reallocation of transmission expense in a rebase / total expense from filed A-13, C4

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1 2. Require that before its next rate case filing, DTE develop substantive
2 programs beyond mere educational outreach to mitigate energy-limiting
3 behavior and assist low-income customers in weatherizing their homes and
4 installing smart thermostats. While this may include aspects of the Company's
5 existing energy waste reduction (EWR) efforts, the Company should do more
6 to understand and mitigate harmful energy-limiting behavior.

7 3. Clarify that, before its next rate case filing, DTE must conduct a targeted
8 analysis focusing specifically on factors impacting low-income customers'
9 ability to shift their energy usage to non-peak hours."³³

10

11 **Q30. How does the Company respond to Witness Nichols' recommendation to**
12 **track post transition bills?**

13 A30. The Company acknowledges Witness Nichols' desire to make the time of use
14 transition seamless and constructive for customers. The Company does not agree
15 that it is necessary or effective to track customer bills for three reasons.

- 16 • Bills are primarily driven by usage, and usage changes month to month and
17 year over year for many reasons. Company Witness Leuker's direct
18 testimony on page 9, lines 10-23 describes the various inputs that influence
19 residential usage, and in summary, weather is a substantial element. Said
20 differently, the impact of D1.11 rate design and pricing is marginal
21 compared to more macro factors, and rate design is not reasonably
22 identifiable as a standalone factor as it pertains to total bills³⁴.
- 23 • The Company transitioned nearly two million customers from D1 (which
24 shared a structure with special low-income rate D1.6) to D1.11 in 2023, at

³³ DAAO Witness Nichols Pg 39

³⁴ Absent a controlled study

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1 the Commission's direction. Across the approximately 95,000 low-income
2 customers on D1.11 today, the Company is not aware of any systemic bill
3 impacts related to the time of use component of rates.

4 • Of the approximately 27,000 customers that will transition to D1.11 in
5 October, about 5,800 were previously on D1.11 prior to switching to D1.6,
6 which before the January Order in Case No. U-21534 was a requirement of
7 receiving the low-income assistance credit. Despite the small impacts that
8 rate changes may have had for some customers, the Company is not aware
9 of any systemic concerns from customers moving between these rates.

10

11 Customers transitioning to D1.11 may also choose any other whole home base rate,
12 including D1.2, D1.8, and D1.13, based on what is most effective for their needs.
13 If options other than D1.11 are preferable for the customer, they now have that
14 choice.

15

16 **Q31. How does the Company respond to Witness Nichols' recommendation**
17 **regarding outreach?**

18 A31. The Commission's final Order in Case No. U-21534 directed the Company, for the
19 ~1/3 of customers in the prior analysis "who may experience higher utility rates as
20 a result of the transition", to implement "expanded educational outreach to low-
21 income customers regarding low-income energy efficiency programs,
22 weatherization, and smart thermostats; and the use of smart meter data to identify
23 customers and address energy-limiting behavior that is adverse to health and safety"

24 ³⁵.

³⁵ Case No. U-21534 Order Pg 394

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1 The Company acknowledges this direction and as such has developed enhanced
2 materials for transitioning customers. Materials sent to customers will include
3 explanations of the rate, the time of use prices themselves, and additional details
4 about EWR programs, including links, for both income-qualified and broad-based
5 programs. The Company is sending these materials not only to the 1/3 who may
6 experience slightly higher bills but to all transitioning customers to ensure as wide
7 as possible communication about available programs. This is a broader set of tools
8 and information than was provided to the ~95,000 low-income customers who
9 transitioned from D1 to D1.11 in 2023 or to those ~5,800 customers who
10 transitioned from D1.11 to D1.6. As described by Company Witness Sparks in his
11 revised direct testimony, the Company maintains many programs for customers
12 who may need assistance, and all remain similarly available on D1.11 as they are
13 on D1.6.

14

15 **Q32. How does the Company respond to Witness Nichols' recommendation**
16 **regarding an additional "targeted analysis"?**

17 A32. The Company conducted an extensive behavioral and rate pilot ahead of the full
18 transition to time of use rates known as the Advanced Customer Pricing Pilot. As
19 provided in discovery and included by Witness Nichols as Exhibit-DAO-6, the final
20 report for this study was 298 pages long. It includes extensive analytics and
21 included more than 2,000 randomly selected low-income customers as part of its
22 robust statistical design. This survey and related analysis was used to develop
23 successful outreach and communication for a transition of almost two million
24 residential customers, among them tens of thousands of low-income customers. The

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1 surveys directly addressed the question of ability to shift usage. A non-exhaustive
2 list includes:

- 3 • Did you change your thermostat schedule for the winter heating season
4 (October – March) to a lower temperature than last year? (DAO-6 Pg 198)
- 5 • After you were enrolled in the Shift & Save pricing plan in 2021, which of
6 the following home warming actions did you or others in your household
7 start or continue to implement on a regular or somewhat regular basis during
8 the winter months (October – March) to reduce the amount of energy you
9 use to warm your house or apartment? (DAO-6 Pg 204)
- 10 • Which one of the following factors do you find most compelling as a reason
11 for changing your normal routine and energy use behaviors on the Shift &
12 Save pricing plan? (DAO-6 Pg 208)
- 13 • How would you characterize your current level of knowledge about how the
14 Shift & Save pricing option works? (DAO-6 Pg 126)

15

16 The Company then confirmed in its Case No. U-21534 analysis that there is no
17 structural impact of D1.11 rate design on D1.6 customers³⁶. Company Witness
18 Gerdes further provided a regression analysis in this case as directed by the
19 Commission, and Company Witness Sparks is addressing the shutoff analysis.
20 Based on the extensive studies and analysis completed by the Company, it is clear
21 that no “more targeted analysis” should be required.

22

23 **Q33. How do you recommend the Commission respond to Witness Nichols’**
24 **recommendations regarding the D1.6 transition?**

³⁶ The Commission found “persuasive the company’s, Staff’s, and CEOs’ arguments that nearly two-thirds of low-income customers would experience reduced utility rates” January Order, Pg 394

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1 A33. I recommend the Commission reject Witness Nichols' recommendations for the
2 reasons described above.

3

4 **Q34. Can you please summarize CEO Witness Kenworthy's testimony and**
5 **recommendations with respect to the D1.6 to D1.11 rate transition?**

6 A34. Yes. Witness Kenworthy describes the prior analyses, Commission Order from U-
7 21534, and the Company's direct testimony in this case. He then describes his
8 understanding of the Company's outreach plan, which he terms as "directionally
9 consistent with the Commission's outreach expectations". His testimony then
10 recommends the Company provide further explanation of its plan to "identify
11 specific customers adversely impacted by the transition period and intervene" and
12 "how it will leverage advanced meter data and any existing 'Home Energy Report'
13 tools."³⁷

14

15 He summarizes by recommending "that the Commission take the following
16 action[s] pursuant to this transition:

17 "Identify and assist low-income customers during the D1.6 to D1.11
18 Time-of-Use transition by requiring AMI-based analytics to flag at-risk
19 households; targeted, multilingual outreach; streamlined enrollment in
20 assistance (e.g., LIA/arrears management); and practical mitigations (e.g.,
21 smart-thermostat support, weatherization referrals, safety checks, and near-term
22 bill-protection where warranted).³⁸

³⁷ CEO Witness Kenworthy Pg 32

³⁸ CEO Witness Kenworthy Pg 33-34

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1 **Q35. What is the Company's response to Witness Kenworthy's testimony and**
2 **recommendations?**

3 A35. The Company appreciates Witness Kenworthy's support of the Company's
4 outreach efforts to all transitioning customers. An initial, introductory mailer was
5 sent to customers in late July / early August and the full welcome kit will arrive in
6 the same week each customer transitions in October. Both pieces of communication
7 are premised on the extensive work and effective approach that supported the initial
8 D1.11 transition in 2023. In addition to this educational and programmatic outreach
9 to all transitioning customers, the Company is developing an approach to leverage
10 AMI data for transitioning customers to further assist them in understanding
11 available efficiency programs and how they use energy. As Witness Kenworthy
12 posits, a tailored version of the Company's Home Energy Report (which leverages
13 AMI data) is one such option under consideration. Regardless of the approach
14 ultimately utilized, transitioning customers need to have usage on D1.11 (or any
15 other rate of their choosing) sufficient to support any further analysis and
16 communication. Thus, there is no "gap relative to the Commission's explicit
17 direction"³⁹ in terms of using smart meter data.

18

19 In addition, the Commission Order in Case No. U-21534 says "the Commission
20 finds that the company shall implement the CEOs' recommended mitigation
21 measures: expanded educational outreach to low-income customers regarding low-
22 income energy efficiency programs, weatherization, and smart thermostats; and the
23 use of smart meter data to identify customers and address energy-limiting behavior
24 that is adverse to health and safety."⁴⁰ As indicated in response to DAAO Witness

³⁹ CEO Kenworthy Pg 31

⁴⁰ Case No. U-21534 Order Pg 394

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1 Nichols, the Company is including extensive information about income-qualified
2 and broad-based EWR programs to transitioning customers, including smart
3 thermostats and weatherization programs. The Company does not interpret the
4 Commission's order to extend to, among other things highlighted by Witness
5 Kenworthy, "near term bill protection". In addition, the Company need not provide
6 additional LIA enrollment support for transitioning customers as each one is
7 presently receiving the LIA credit (for which D1.6 enrollment was previously
8 required).

9

10 Lastly, as noted above, about 5,800 of the ~28,000 transitioning customers were
11 previously on D1.11, and there are no structural or systemic issues the Company is
12 aware of related to those rate changes. This transition is essentially no different.

13

14 **Seasonal Distribution Rates**

15 **Q36. Can you please describe MNC Witness Jester's recommendations regarding**
16 **seasonal distribution rates?**

17 A36. Yes. Witness Jester's testimony recommends that the Commission "direct DTEE
18 to propose seasonal distribution rates in its next rate case". MNC Witness Jester
19 notes that, according to MNSC Witness Woolley, distribution system utilization is
20 seasonal, and from this concludes that because increases in winter demand would
21 apparently not drive additional grid capacity investments, the Company should
22 move towards seasonal distribution rates⁴¹. Witness Jester then describes "four
23 salutary effects⁴²" of seasonal distribution rates.

⁴¹ MNC Witness Jester Pg 36

⁴² MNC Witness Jester Pg 36

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1 The first is framed as cost of service and equitable rate design, as Witness Jester
2 says:

3 “it would more accurately bill customers for their cost of service, with
4 customers that have relatively high summer share of electricity usage
5 paying more than under the current rate design and customers with relatively
6 high winter share of electricity usage paying less. Amongst residential
7 customers, low-income customers and occupants of multi-family dwellings
8 tend to have lower air conditioning usage and higher incidence of electric heat,
9 so seasonal distribution rates would make rate design more equitable.”⁴³

10

11 The second is on the topic of “unfairness in current rate design” arising from the
12 fact that while certain costs are allocated in cost of service on a summer peak
13 demand basis, electric heat customers “have significantly greater kWh sales than
14 customers that use fossil-fueled heat but have similar summer peak demand⁴⁴”.
15 This, Witness Jester concludes, results in electric heat customers “overpay[ing]”
16 their cost of service and that seasonal distribution rates, or an electric space heating
17 rate, are the solution.

18

19 The third is that higher summer distribution rates will incentivize customers to
20 adopt energy efficiency measures that they would not otherwise adopt.

21

22 And the fourth is that seasonal distribution rates “may enable customers to adopt
23 electric heat by making it less costly to operate”⁴⁵.

⁴³ MNC Witness Jester Pg 37

⁴⁴ MNC Witness Jester Pg 37

⁴⁵ MNC Witness Jester Pg 38

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1 Witness Jester then proposes that the costs of “substations, transformers, and related
2 equipment” be allocated entirely to summer energy rates while “poles, wires, and
3 conduit” be recovered across the year. According to Witness Jester, the basis for
4 the split is that the former group is sized based on peak demand and the latter group
5 represents “relatively little incremental cost [driven] by peak demand”⁴⁶.

6
7 **Q37. Does the Company agree with MNC Witness Jester’s proposal?**

8 A37. No. In the Company’s prior general rate case, Witness Jester offered a substantially
9 similar proposal. In summary, Witness Jester previously asked the Commission to
10 direct the Company to develop cost of service and rate design proposals for space
11 heating and multifamily. In describing its proposal, MNSC’s brief in that case said
12 it is, “about the benefits of allocating distribution costs seasonally in combination
13 with creating residential subclasses for multi-family and electric heating
14 customers⁴⁷”. This is an almost identical premise to what Witness Jester suggests
15 on Page 37 of his direct testimony, which is cited in full above. In its final Order
16 in Case No. U-21534, the Commission declined to adopt Witness Jester’s similar
17 proposal, saying:

18 “The Commission respectfully declines to adopt MNSC’s request that DTE
19 Electric be directed to file in its next rate case an analysis of the seasonality for
20 cost causation of distribution costs and distribution rate designs consistent with
21 that seasonality. The Commission finds that MNSC’s recommendation was not
22 sufficiently detailed in testimony to allow the company to respond or for the

⁴⁶ MNC Witness Jester Pg 38

⁴⁷ January 23, 2025 Order, Case No. U-21534, Pg 378

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1 Commission to determine whether such a study would be necessary and
2 beneficial.⁴⁸”

3

4 As an initial matter, there is similarly insufficient detail in MNC Witness Jester’s
5 proposal in this case. While the Company acknowledges that MNSC Witness
6 Woolley has provided transformer network utilization charts, Witness Jester does
7 not provide any analytic or quantitative connection between the pattern of system
8 transformer utilization and why those patterns should dictate changes in cost
9 allocation and rate design. Nor is Witness Jester suggesting minor changes – taken
10 at face value a requirement to propose seasonal distribution rates could plausibly
11 apply to all rate schedules offered by the Company and impact each of its ~2.3
12 million customers. On this basis alone I recommend the Commission reject the
13 proposal.

14

15 Substantively, I also recommend the Commission reject the proposal for several
16 reasons. While Witness Jester writes that certain groups of customers have different
17 space conditioning patterns and therefore would be more appropriately served by
18 seasonal distribution rates, there is no analysis provided which supports either the
19 assertion of different appliance usage profiles for certain customer types or the
20 assertion that a seasonal rate is therefore appropriate. Nor has Witness Jester
21 provided any analysis of the uptake in energy efficiency interventions that may
22 occur solely because of this proposed change in rate design.

⁴⁸ January 23, 2025 Order, Case No. U-21534, Pg 380

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1 There is similarly no analysis provided that 1) the load factors for electric heat
2 customers are materially different than all other customers, 2) electric heat
3 customers are overpaying, or 3) seasonal distribution rates or a standalone rate solve
4 either of those perceived issues. In addition, Case No. U-21534 featured extensive
5 evidence and briefing on the topic⁴⁹ and there is no additional information provided
6 in this case. And I will reiterate my own rebuttal from the prior case – the Company
7 has an electric space heating rate that the Commission closed to new customers.

8

9 **EV Topics**

10 **Q38. Can you please summarize the proposals regarding EV tariffs and rate design**
11 **to which you will respond?**

12 A38. Yes. I will respond to:

- 13 • Staff Witness Krause’s recommendation that “the Company propose a new
14 tariff for fast charging in its next rate case based on available fast charging data”
15 and that “the utility provided rate design options that consider charging station
16 uptime and charging reliability”⁵⁰
- 17 • Walmart Witness Lyon’s recommendation that the Commission “direct the
18 Company to plan, develop, and announce a stakeholder convening agenda and
19 schedule as soon as is prudent to allow for sufficient opportunity and time to
20 develop a consensus-based EV fast charging rate proposal to present to the
21 Commission no later than December 1, 2026.”⁵¹
- 22 • Staff Witness Isakson’s recommendation, regarding the EV minimum service
23 tariff proposal, that “the Company propose on rebuttal a new wording of the

⁴⁹ See generally Pgs 370-380 of the January 23 order

⁵⁰ Staff Witness Krause Pg 5

⁵¹ Walmart Witness Lyons Pg 26

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1 sentence “Residential minimum service is 10 kW of connected load” to avoid
2 the confusion identified by Staff or remove the sentence entirely.”⁵²

3

4 **Q39. How do you respond to Staff Witness Krause’s proposals?**

5 A39. The Commission in its January 2025 Order in Case No. U-21534 said “DTE
6 Electric shall file its proposal for a successor EV fast charger rate, informed by
7 input from interested parties, no later than December 1, 2026, in order to allow for
8 approval and implementation well in advance of the June 2028 expiration of the
9 demand charge holiday.”⁵³ The Company is planning to meet the Commission’s
10 December 2026 direction for a standalone fast charger rate as well as the
11 collaboration contemplated in the same Order. It is not evident that there is a reason
12 to modify the prior Order and, as such, the Company recommends no change to the
13 timing in the January 2025 Order.

14

15 The Company understands that there are a variety of considerations to balance
16 when designing an EV fast charger rate and looks forward to future discussions.
17 However, the Company does not believe it’s appropriate to be directed to design
18 for the specific characteristics highlighted by Witness Krause (e.g., consider
19 charging station uptime and charging reliability). The Company designs first for
20 cost of service, and while there are likely design options that support additional
21 considerations, the Company should not be held to them at this early stage. The
22 stakeholder engagement and subsequent filing is the more appropriate venue to
23 explore tradeoffs in rate design.

⁵² Staff Witness Isakson Pg 16

⁵³ January 2025 Order, Page 426

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1 **Q40. How do you respond to Walmart Witness Lyon’s proposal?**

2 A40. The Company notes that the Commission already directed stakeholder engagement
3 ahead of the December 2026 filing, and no change in course is required.

4

5 **Q41. How do you respond to Staff Witness Isakson’s proposal?**

6 A41. The Company does not have any concerns with Witness Isakson’s proposal
7 regarding the EV minimum service tariff proposal to remove the subject sentence
8 entirely.

9

10 **Q42. Does this conclude your rebuttal testimony?**

11 A42. 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

REBUTTAL TESTIMONY

OF

RODRIGO CEJAS GOYANES

Line
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3 A1. My name is Rodrigo Cejas Goyanes. My business address is One Energy Plaza,
4 Detroit, Michigan, 48226. I am employed by DTE Energy Corporate Services,
5 LLC, a subsidiary of DTE Energy Company as a Regulatory Strategy Consultant,
6 Regulatory Economics.

10 A2. Yes.

11

13 A3. Yes. I am supporting the following exhibit:

A-38 CC1 Excerpt from NARUC Manual – Classification and Allocation of Distribution Plant Section

17

20 A4. The purpose of my testimony is to respond to intervenor direct testimony,
21 specifically addressing the topics listed below. The absence of rebuttal on any given
22 matter does not constitute agreement by the Company.

23 1) Respond to Michigan Environmental Council, Natural Resources Defense
24 Council, and Citizens Utility Board of Michigan (MNC) Witness Jester's

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1 recommendation to change the allocation of certain distribution cost categories
2 in the Cost-of-Service Study (COSS);
3 2) Respond to Association of Businesses Advocating Tariff Equity (ABATE)
4 Witness Andrews' proposal regarding the functionalization and allocation of
5 Transportation Electrification Plan (TEP) costs.
6

7 **MNC Proposal to Change Allocation Method of Distribution Costs in the COSS**

8 **Q5. Does MNC Witness Jester recommend changes in the approved allocation**
9 **methods for certain distribution costs in the COSS?**

10 A5. Yes. In his direct testimony (page 38, line 10 to page 39, line 2), MNC Witness
11 Jester argues that, if the Commission were persuaded to adopt seasonal distribution
12 rates, those rates should be based on the principle that the costs of poles, wires and
13 conduit should be allocated to energy throughout the year and that costs of
14 substations, transformers, and related equipment should be allocated to summer
15 energy. Witness Jester further states (page 38, lines 16-18), "contrary to the use of
16 a demand allocator in the COSS, several of these cost categories are not materially
17 driven by demand."
18

19 **Q6. Is your rebuttal testimony addressing Witness Jester's proposal for seasonal**
20 **distribution rates?**

21 A6. No, Company Witness Willis will be addressing Witness Jester's proposal for
22 seasonal distribution rates in his rebuttal testimony.
23

24 **Q7. Can you summarize Witness Jester's basis for proposing changes in the**
25 **classification and allocation of certain distribution costs?**

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1 A7. In support of his proposal to adopt seasonal distribution rates, Witness Jester states
2 on page 38, lines 16–18 of his direct testimony that “contrary to the use of a demand
3 allocator in the COSS, several of these [distribution plant] cost categories are not
4 materially driven by demand.” In making this claim, Witness Jester appears to be
5 conflating the terms “allocate” and “classify,” suggesting that certain distribution
6 plant costs are driven by energy consumption and should therefore be classified as
7 energy related.

8
9 For context, classification refers to the cost-of-service step that determines whether
10 costs are primarily driven by demand, energy, or customer count. Following
11 classification, the allocation process assigns those classified costs to customer
12 classes based on their respective contributions to total demand, energy usage, or
13 customer count.

14
15 Witness Jester’s proposal implies reclassifying certain distribution plant costs as
16 energy driven. Within that framework, he then recommends allocating poles, lines,
17 and conduit based on each class’s share of annual energy usage, and allocating
18 substations and transformers based on each class’s contribution to summer energy
19 usage.

20

21 **Q8. Do you agree with Witness Jester’s proposed change?**

22 A8. No. Witness Jester’s proposed changes to the classification and allocation of certain
23 distribution costs should be dismissed for three reasons: (1) Witness Jester does not
24 provide a technical justification for how energy consumption drives equipment
25 sizing and associated costs for distribution plant; (2) without a causal explanation

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1 for how energy consumption drives equipment sizing and associated costs, Witness
2 Jester's proposal contradicts the cost causation principle of cost-of-service; and (3)
3 Witness Jester's proposal also contradicts the classification and allocation methods
4 prescribed by the National Association of Regulatory Utility Commissioners
5 (NARUC) in their Electric Utility Cost Allocation Manual (Electric Utility Cost
6 Allocation Manual, National Association of Regulatory Utility Commissioners,
7 January, 1992) (NARUC Manual). I expand on each of these reasons below.

8

9 **Q9. Does Witness Jester provide support for his assertion that energy usage drives**
10 **distribution equipment costs?**

11 A9. No. Witness Jester generally asserts that certain distribution cost categories are
12 driven more by energy usage than by demand. However, he offers no supporting
13 analysis, detail, or technical explanation to justify this claim or to challenge the
14 current use of demand- or customer-based allocation methods. Furthermore, his
15 argument appears inconsistent on occasions. For example, he acknowledges that
16 "substations, transformers, and some other equipment are sized based on demand,"
17 (page 38, lines 19-20) yet later recommends that the costs of this same equipment
18 should be allocated based on summer energy usage (page 39, lines 1-2). It would
19 be inconsistent to classify the costs of substations, transformers, and other
20 equipment as demand-driven costs, and to then allocate those demand-driven costs
21 based on the amount of energy that each customer class consumed.

22

23 **Q10. Does Witness Jester's proposal violate cost-of-service principles?**

24 A10. Yes. Witness Jester's recommendation to classify and allocate certain distribution
25 plant costs based on energy contradicts the principle of cost causation. The

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1 parameters used to design and build the system are what determines and causes the
2 costs of the system. As I summarized in my direct testimony on lines 10 to 12 of
3 page 19, distribution system design costs are caused (driven) by the number of
4 customers served and the maximum demand placed on the system at a given voltage
5 level. Company Witness Chiu provides additional rebuttal testimony that demand,
6 and not energy consumption, is the key parameter that drives and causes
7 distribution equipment selection. Specifically, the peak instantaneous
8 demand within a given geographic service area, along with the number of
9 customers served, are the main factors influencing the sizing and associated costs
10 of distribution infrastructure—including poles, lines, conduit, substations, and
11 transformers.

12

13 **Q11. Does Witness Jester’s recommendation align with the NARUC Manual for**
14 **cost classification and allocation?**

15 A11. No. Witness Jester’s suggestion to allocate distribution costs based on energy
16 conflicts with the general guidelines for classification of distribution plant and
17 expenses as described in the NARUC Manual, which is commonly used as a
18 standard guide for electric utility cost classification and allocation. The NARUC
19 Manual classifies both distribution plant and expenses as being demand-related,
20 customer-related, or a combination of the two (Electric Utility Cost Allocation
21 Manual, National Association of Regulatory Utility Commissioners, January,
22 1992). The NARUC Manual does not contemplate classifying any portion of
23 distribution-related costs (e.g., distribution plant, distribution O&M) based on
24 energy. In fact, on page 89, the NARUC Manual states that, “Because there is no
25 energy component of distribution-related costs, we need consider only the demand

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1 and customer components.” Tables 6-1 and 6-2 in the NARUC Manual provide a
2 list of all the FERC accounts for distribution plant and expense with the appropriate
3 classification for each account, none of which includes energy-based
4 classifications. For reference, please see Exhibit A-38 Schedule CC1.

5

6 **Q12. In summary, what is your recommendation regarding Witness Jester’s**
7 **proposal to change the approved classification and allocation methods for**
8 **certain distribution costs in the COSS?**

9 A12. I recommend that the Commission reject Witness Jester’s proposal to allocate costs
10 based on annual energy usage for poles, wires, and conduits, and summer energy
11 usage for substations, transformers, and related equipment. This proposal should be
12 rejected because it (1) lacks adequate support, (2) contradicts cost causation
13 principles, and (3) conflicts with the NARUC Manual, which is a standard for cost
14 classification and allocation in the utility industry.

15

16 **ABATE Proposal Regarding Functionalization and Allocation of TEP Costs**

17 **Q13. What is ABATE Witness Andrews’ recommendation regarding**
18 **functionalization and allocation of TEP Costs?**

19 A13. Witness Andrews is proposing to change the currently approved functionalization
20 and allocation of TEP costs in the COSS. On lines 6 and 7 of page 7 of his
21 testimony, Witness Andrews states that “it is most appropriate to functionalize them
22 nearly entirely, if not entirely, as distribution.” On lines 9 and 10 of page 7, Witness
23 Andrews continues that “on allocation, it would be most appropriate to directly
24 allocate these costs into the customer classes that use the rebates.” Witness
25 Andrews requests that, in the next case, the Company be required to report total

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1 paid rebates broken out by customer class and voltage level. Witness Andrews
2 argues that this data would support his proposed methodology for directly
3 allocating TEP costs to the classes that use the rebates.

4

5 **Q14. What is the Commission's approved method for functionalization and**
6 **allocation of TEP costs?**

7 A14. In its December 1, 2023 Order in Case No. U-21297, pages 294-295, the
8 Commission approved the allocation methodology for TEP costs. Under this
9 approach, the TEP costs are first functionalized between power supply and
10 distribution on the basis of present revenues. Then, once functionalized between
11 power supply and distribution, the costs are allocated to customer classes on the
12 basis of each class's share of present revenues. The Company applies the allocators
13 400a and 401 in the COSS that reflect present or billed revenues. This
14 functionalization and allocation methodology has been consistently used by the
15 Company in its general rate cases since the Commission's Order in Case No. U-
16 21297.

17

18 **Q15. What is Witness Andrews' argument to propose a change in the currently**
19 **approved methodology?**

20 A15. On page 6 lines 11-14 of his direct testimony, Witness Andrews argues that the
21 Staff's position that "the [TEP] costs should be allocated to customer classes based
22 on class revenues, because the TEP programs are being pursued to lower rates for
23 all DTE customers, is highly tenuous and should be rejected."

24

25 **Q16. What is your opinion of Witness Andrews' argument and recommendation?**

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1 A16. I maintain that Witness Andrews' argument does not provide a compelling reason
2 to change the currently Commission-approved method for functionalizing and
3 allocating TEP costs. As the Commission recognized in its Order in Case No. U-
4 21297, the primary benefit is downward pressure on rates for all customers.
5

6 **Q17. What is your recommendation of Witness Andrews' position on the**
7 **functionalization and allocation of TEP costs?**

8 A17. I recommend the Commission reject Witness Andrews' proposal regarding the
9 functionalization and allocation of TEP costs, as his arguments do not provide a
10 compelling reason to change the methodology approved by the Commission in
11 Case No. U-21297. Thus, his request for the Company to report total rebates by
12 customer class and voltage level in future proceedings should also be dismissed, as
13 it would create an unnecessary administrative burden and is not relevant to the
14 Commission-approved cost allocation methodology.
15

16 **Q18. Does this conclude your rebuttal testimony?**

17 A18. Yes, it does.

STATE OF MICHIGAN
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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

REBUTTAL TESTIMONY

OF

ANTHONY TURNER

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF ANTHONY TURNER

Line
No.

1 **Q1. Please state your full name, title, business address and by whom you are**
2 **employed?**

3 A1. My name is Anthony Turner. My business address is One Energy Plaza, Detroit,
4 Michigan 48226. I am employed by DTE Energy Corporate Services, LLC, a
5 subsidiary of DTE Energy Company (DTE Energy), as a Senior Strategist within
6 Regulatory Affairs.

7

8 **Q2. Did you file direct testimony in this proceeding on behalf of DTE Electric**
9 **Company (DTE Electric or Company)?**

10 A2. Yes.

11

12 **Purpose of Testimony**

13 **Q3. What is the purpose of your rebuttal testimony?**

14 A3. The purpose of my rebuttal testimony is to address the direct testimony of ABATE
15 Witness Andrews concerning the demand/energy split for primary customers, and
16 to address Electrify America Witness Shah's testimony regarding the rate design
17 for Rate Schedule D3.5. The absence of rebuttal on any given matter does
18 not constitute agreement by the Company.

19

20 **Q4. Are you sponsoring any exhibits as part of your rebuttal testimony?**

21 A4. No.

22

23 **Demand/ Energy Split**

24 **Q5. Can you summarize ABATE Witness Andrew's proposal regarding the power**
25 **supply demand/energy split for primary customers?**

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1 A5. Yes. ABATE Witness Andrews provides “an analysis based on DTE’s 2025 power
2 supply cost components”¹ to assert that a 63/37 split of demand and energy costs
3 should be adopted for primary rates with demand and energy charges. He goes on
4 to conclude that “for the Primary rates with demand charges and energy charges, I
5 recommend that 63% of the power supply costs be recovered through demand
6 charges, with the transmission costs being recovered through the non-capacity
7 demand charge, and the remainder of the 63% of fixed costs being recovered
8 through the capacity demand charge. 37% of the power supply revenues from these
9 classes should be recovered through the non-capacity energy charge.”²

10

11 **Q6. How is the power supply demand/energy split currently calculated for primary**
12 **rates?**

13 A6. The power supply demand/energy split is based on the ratio between the present
14 share of power supply revenue collected through demand charges and the present
15 share of power supply revenue collected through energy charges. This methodology
16 was approved by the Michigan Public Service Commission (MPSC or
17 Commission) in Case No. U-21297³ and subsequently in Case No. U-21534 and
18 has remained unchanged since.

19

20 **Q7. How was the currently approved methodology established for determining the**
21 **demand/energy split?**

22 A7. In Case No. U-21297, both Staff and ABATE proposed to maintain the current ratio
23 between demand and energy. The Commission ultimately found that “the current

¹ ABATE Witness Andrews, Pg 14

² ABATE Witness Andrews, Pg 15

³ December 1,2023 Order in Case No. U-21297, Pg 328

Line
No.

1 ratio between demand and energy charges for Rate Schedules D4, D6.2, and D11
2 should be maintained.”⁴ This methodology also was most recently approved in the
3 Company’s last rate case, Case No. U-21534. Notably, as ABATE Witness
4 Andrews admits on page 15 of his direct testimony, he also proposed the very
5 methodology he is proposing in the instant case in Case No. U-21297, which the
6 Commission declined to adopt.

7
8 **Q8. Does the SRM Capacity charge affect the approved demand/energy split**
9 **ratios?**

10 A8. No. ABATE Witness Andrews asserts that “volatility in the SRM capacity charge
11 can cause significant swings in the capacity-related power supply charge and non-
12 capacity-related charge split of the primary customer rates. This in turn can
13 problematically impact the split between total (capacity plus non-capacity) power
14 supply demand charges and total power supply energy charges...”⁵ Witness
15 Andrews is incorrectly conflating 1) the revenue requirement allocation for
16 capacity vs. non-capacity power supply revenue with 2) the split between how
17 much power supply revenue is recovered through demand vs. energy rates. The
18 Company’s proposed demand and energy rates (used for collection of the power
19 supply revenues) maintains the current ratio between demand and energy charges
20 found in present revenues. Thus, the SRM capacity charge and the amount to be
21 recovered through capacity versus non-capacity power supply revenue has no
22 impact on the demand/energy charge split ratios.

⁴ *Id.*

⁵ ABATE Witness Andrews, Pg 9

Line
No.

1 **Q9. Does Witness Andrews provide an accurate depiction of the current rate**
2 **design structure for Rate Schedule D11?**

3 A9. No. Witness Andrews states “It first makes sense to discuss the power supply
4 components of Rate D11. There are three primary components. The capacity
5 demand charge, which recovers the portion of the allocated power supply revenue
6 requirement that has been deemed “capacity-related” due to the SRM capacity
7 charge calculation. The second component is the non-capacity demand charge,
8 which historically has been used to recover the allocated transmission expense.
9 Finally, there is the non-capacity energy charges, which recover the remainder of
10 the allocated power supply revenue requirement.”⁶ To clarify, Witness Andrew’s
11 description reflects the Company’s prior D11 rate design methodology, which was
12 updated with the Commission’s decision in Case No. U-21297. Under the current
13 Commission-approved framework—reaffirmed in Case No. U-21534—Rate
14 Schedule D11 is designed to maintain the proportional relationship between
15 demand-based and energy-based power supply revenue recovery found in present
16 rates while recovering the full power supply capacity revenue requirement through
17 capacity charges and full power supply non-capacity requirement through non-
18 capacity charges. In the instant case, as outlined in my direct testimony, the
19 Company is proposing to introduce a capacity energy charge to maintain this
20 relationship.

21

22 **Q10. Is ABATE’s proposal appropriate?**

23 A10. No. Witness Andrews’ primary recommendation is to use his analysis of power
24 supply cost types to determine demand and energy charges. Witness Andrews also

⁶ ABATE Witness Andrews, Pgs 11-12

Line
No.

1 proposes to depart from the capacity and non-capacity revenue requirement
2 framework approved by the Commission and supported by Company Witness
3 Cejas-Goyanes, opting instead to reclassify power supply costs based on his own
4 assessment of which costs are fixed versus variable. This point is reflected in his
5 proposed rate design—see for example Witness Andrews’ proposed design for Rate
6 Schedule D6.2 in Exhibit AB-6.⁷ As outlined by Company Witness Cejas Goyanes
7 in Exhibit A-16, Schedule F1.5, the proposed capacity revenue requirement for
8 Rate Schedule D6.2 is \$38,979,000, and the non-capacity requirement is
9 \$17,765,000. However, under Witness Andrews’ proposal, only \$30,902,000
10 would be recovered through capacity charges, resulting in an under collection of
11 the capacity revenue requirement by approximately \$8 million, while non-capacity
12 charges would be over collected at \$25,841,000—exceeding the non capacity
13 revenue requirement by approximately \$8 million. This approach would represent
14 a significant departure from the established cost of service methods, as sponsored
15 by Company Witness Cejas Goyanes, and rate design methodologies approved by
16 the Commission in prior cases. The Company does not design power supply rates
17 for any rate schedule based on specific line-item costs nor segregate them as fixed
18 or variable, as Witness Andrews proposes to do.

19

20 **Q11. Please summarize your recommendations to the Commission on the**
21 **demand/energy split for primary customers.**

22 A11. I recommend that the Commission:

- 23 • Reject ABATE’s proposal to use power supply line-item costs as the basis
24 for determining a demand/energy split for primary rate design; and

⁷ ABATE Witness Andrews, Exhibit AB-6, Pg 3

Line
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- 1 • Maintain the current methodology for demand/energy split for primary rate
2 design and adopt the Company’s proposal to introduce a capacity energy
3 charge to adhere to the Commission-approved methodology.

4

5 **Rate Schedule D3.5**

6 **Q12. Can you summarize Electrify America Witness Shah’s argument as it relates**
7 **to Rate Schedule D3.5?**

8 A12. Yes. Witness Shah raises concerns around Rate Schedule D3.5 and its potential
9 market impacts. Witness Shah compares Rate Schedule D3.5 to Rate Schedule D3,
10 the rate under which charging station operators including Electrify America
11 currently take service, stating, “[t]he total energy charges [for Rate Schedule D3]
12 before surcharges and credits sums to \$0.14034 per kWh, which is roughly 75%
13 higher than the proposed on-peak volumetric component of Rate Schedule No.
14 D3.5.”⁸ Witness Shah emphasizes that “[t]his potential dynamic is alarming,
15 regardless of the session charge component.”⁹ He concludes with a
16 recommendation stating, “the session fee and volumetric components of Rate
17 Schedule No. D3.5 should be updated to reflect market rates for public fast charging
18 infrastructure at similar power levels in DTE’s service area.”¹⁰ This, he argues,
19 would “help remove doubts for non-utility EV charging infrastructure operators
20 such as Electrify America to facilitate continued investments in DTE’s service
21 area.”¹¹

22

⁸ Electrify America Witness Shah, Pg 5

⁹ *Id.*

¹⁰ Electrify America Witness Shah, Pg 6

¹¹ *Id.*

Line
No.

1 **Q13. How do the design elements of Rate Schedule D3.5 compare to those of Rate**
2 **Schedule D3?**

3 A13. Rate Schedule D3.5 incorporates two primary design elements: a time of use
4 volumetric component applicable to power supply non-capacity costs, and a fixed
5 session fee designed to recover power supply capacity costs, distribution costs, and
6 a portion of capital investment. In contrast, Rate Schedule D3 consists of three
7 distinct volumetric charges: a power supply capacity energy charge, a power supply
8 non capacity energy charge, and a distribution charge. Due to the structural
9 differences in cost recovery mechanisms, particularly the inclusion of capacity and
10 distribution costs within the fixed session fee under Rate Schedule D3.5, it is
11 inappropriate to compare the two rate schedules solely on the basis of their
12 volumetric rates. Simply put, the session fee cannot be ignored when attempting to
13 compare the two rates. Any comparison that excludes the session fee simply does
14 not reflect the totality of the rate and is flawed.

15

16 **Q14. Considering the structure and intent of Rate Schedule D3.5, do you believe its**
17 **rate design creates an unfair competitive advantage over private EV charging**
18 **providers?**

19 A14. The pilot's structure was not intended to compete with or displace private
20 investment, but rather to explore utility-owned charging in a controlled and
21 transparent manner. Any future expansion or modification of this rate would be
22 subject to Commission review and stakeholder input. Therefore, the claim that Rate
23 Schedule D3.5 inherently distorts competition is not supported when the full rate
24 design and policy context are considered. Moreover, utilities are required to design
25 rates based on cost-of-service principles, which reflect the actual costs incurred in

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1 providing electric service to customers. These principles are distinct from external
2 market-based pricing strategies used by private entities, and are intended to ensure
3 fairness, transparency, and regulatory compliance rather than respond to
4 competitive market dynamics.

5

6 **Q15. Given that DTE Electric has no current or planned deployment of DCFC**
7 **infrastructure under Rate Schedule D3.5, is it reasonable to conclude that the**
8 **D3.5 rate poses a competitive threat to private EV charging providers?**

9 A15. No. The Company has confirmed through discovery responses that it does not
10 currently operate, nor does it plan to install, any utility-owned DC fast charging
11 infrastructure through 2028. Rate Schedule D3.5 was designed to support a limited
12 pilot applicable to a maximum of 100 chargers and is not currently in use. As such,
13 concerns about competitive impacts are speculative and premature. The pilot's
14 existence in the rate book alone does not constitute market interference, particularly
15 given its limited scope and the regulatory oversight that ensures any future
16 deployment aligns with public interest and stakeholder engagement.

17

18 **Q16. What is your recommendation to the Commission on Rate D3.5?**

19 A16. The Commission should reject Electrify America's proposal to "update" the session
20 fee and volumetric components of Rate Schedule D3.5 to reflect market rates.

21

22 **Q17. Does this conclude your rebuttal testimony?**

23 A17. 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

REBUTTAL TESTIMONY

OF

KIRK M. VANGILDER

DTE ELECTRIC COMPANY
REBUTTAL 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. Did you file direct testimony in this proceeding on behalf of DTE Electric**
9 **Company (DTE Electric or Company)?**

10 A2. Yes.

11

12 **Purpose of Testimony**

13 **Q3. What is the purpose of your rebuttal testimony?**

14 A3. The purpose of my rebuttal testimony is to respond to the direct testimony of
15 Michigan Public Service Commission Staff (Staff) Witness Justin J. Hecht relative
16 to his inaccurate calculations of the net rate base, depreciation expense, and
17 property tax expense impacts derived from certain capital disallowances proposed
18 by Staff. Additionally, I will be providing the revenue deficiency impacts related
19 to the changes with the Trenton Channel Battery Energy Storage System (BESS).

20

21 The absence of a discussion of other matters in my rebuttal testimony should not
22 be taken as an indication that I agree with other aspects of any Staff or intervenor
23 testimony.

24

25 **Q4. Are you sponsoring any exhibits in this proceeding?**

Line
No.

1 A4. Yes. I am sponsoring the following exhibits:

2	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
3	A-56	XX1	Capital Disallowance Calculation Variance
4	A-56	XX2	Trenton Channel BESS Revenue Deficiency Change

5

6 **Q5. Were these exhibits prepared by you or under your direction?**

7 A5. Yes, they were.

8

9 **Capital Disallowance Calculation Variance**

10 **Q6. Staff Witness Hecht's direct testimony features a table described as Figure 1**
 11 **and a supporting workpaper called WP-JJH-1 was provided which included**
 12 **the calculations of several components needed to determine DTE Electric's**
 13 **revenue deficiency. Do you agree that these calculations are correct?**

14 A6. The calculations are largely correct; however, several of Staff's proposed
 15 disallowances included in the workpaper have incorrect calculations.

16

17 **Q7. Which of Staff's proposed capital disallowances have inaccurate calculations**
 18 **for their net rate base, depreciation expense, and property tax expense**
 19 **impacts?**

20 A7. Staff's provided workpaper JJH-1 (WP-JJH-1) in support of the amounts listed in
 21 Figure 1 contains several proposed disallowances that have calculation errors due
 22 to the date on which they are expected to be placed in service.

23 • "Mobile Timesheets" and "Vegetation Management Replatform" (WP-JJH-
 24 1 rows 18 and 19, respectively) each are listed with an In-Service Year of
 25 2027. As such, these projects are expected to be in Construction Work in

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1 Process (CWIP) as of the end of the projected test year (the twelve months
2 ended December 31, 2026) and the disallowance of this capital spend would
3 not have any impact on DTE Electric's proposed revenue deficiency.

4 • "Infrastructure and Modernization - Lack of Detail" (WP-JJH-1 row 11)
5 calculates the impacts due to the disallowance of a multitude of projects that
6 have various in-service dates, and as such the "one size fits all" formulas
7 used in WP-JJH-1 do not accurately reflect what the impact to net rate base,
8 depreciation expense, and property tax expense would be if they are
9 disallowed.

10

11 **Q8. How should the changes to net rate base, depreciation expense and property**
12 **expense be calculated?**

13 A8. Please refer to my Exhibit A-56, Schedule XX1 titled "Capital Disallowance
14 Calculation Variance". In this exhibit I break down the capital project components
15 of Witness Shi's "Infrastructure and Modernization - Lack of Detail" disallowance
16 based on the capital projects included in this disallowance and their respective in-
17 service assumptions. The projects in this disallowance are broken into three
18 categories:

19 • **Projects in-serviced annually or before 2026** – the calculation used by
20 Staff for these projects appears reasonable and appropriate.

21 • **Projects in-serviced entirely during 2026** – the calculation used by Staff
22 includes any prior period spend as part of the beginning Plant In Service
23 balance for the test year. When assets are placed in service during the test
24 year, the beginning Plant In Service balance should be zero and the ending
25 balance should be all capital spend to date with average plant calculated

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1 from these amounts. Similarly, accumulated depreciation should not be
2 calculated for any periods prior to the test year. These inaccuracies impact
3 the calculation for Average Net Rate Base (for which DTE Electric receives
4 a return) as well as depreciation expense. Lastly, property tax expense for
5 these projects should be calculated utilizing the first year State Tax
6 Commission (STC) multiplier of 50%, as the associated assets would have
7 been in CWIP as of 12/31/2025.

8 • **Projects in-serviced after 2026** – projects in this category should have
9 limited impact on revenue deficiency with the exception of property taxes
10 for any CWIP that existed as of the beginning of the test year. Just as above,
11 property tax expense for these projects should be calculated utilizing the
12 first year STC multiplier of 50%, as the associated assets would have been
13 in CWIP as of 12/31/2025. As discussed by Company Witness Uzenski in
14 her revised direct and rebuttal testimony, a disallowance of projects that do
15 not go into service during the projected test period, on which Allowance for
16 Funds Used During Construction (AFUDC) is accrued, should not have any
17 impact on requested rate relief due to the AFUDC offset booked to the
18 income statement.

19

20 **Q9. What information is included on lines 33 and 34 of Exhibit A-56, Schedule**
21 **XX1?**

22 A9. As mentioned previously, additional projects proposed for disallowance by Staff
23 Witness Shi include “Mobile Timesheets” and “Vegetation Management
24 Replatform” (WP-JJH-1 rows 18 and 19, respectively) which are listed with an In-

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1 Service Year of 2027. As such, their calculations should be performed the same as
2 those other projects in-serviced after 2026 as described above.

3

4 **Q10. What is your conclusion regarding the information provided on Exhibit A-56,**
5 **Schedule XX1?**

6 A10. As summarized on line 41 of the exhibit, Staff should increase their proposed
7 revenue deficiency by \$5.1 million: \$3.2 million for the return on rate base, \$1.8
8 million for depreciation expense, and approximately \$74,000 for property tax
9 expense.

10

11 **Trenton Channel BESS Revenue Deficiency Change**

12 **Q11. What is the purpose of Exhibit A-56, Schedule XX2?**

13 A11. Multiple intervening witnesses proposed a disallowance to the Trenton Channel
14 BESS forecasted capital spend based on the Company's response to Staff's
15 discovery question STDE-13.1b. Company Witness Guillaumin discusses this
16 further in her rebuttal testimony.

17

18 In addition, Staff Witness DeCooman requested that the Company provide an
19 estimated impact on revenue deficiency based on the changes to the forecasted
20 spend. My Exhibit A-56, Schedule XX2 provides that calculation.

21

22 **Q12. What is included in your exhibit?**

23 A12. Line 1 of my exhibit calculates the estimated revenue deficiency impacts associated
24 with the Trenton Channel BESS capital spend as it was included in DTE Electric's
25 application. Line 3 then calculates the revised revenue deficiency impacts based

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1 on the updated forecast provided in discovery response STDE-13.1b. In both
2 scenarios, the Trenton Channel BESS project is expected to be placed in service
3 during 2026, and as such the formulas utilized are consistent with the formulas
4 described above for “Projects in-serviced entirely during 2026” when discussing
5 Exhibit A-56, Schedule XX1.

6

7 **Q13. What is your conclusion regarding the information provided on Exhibit A-56,**
8 **Schedule XX2?**

9 A13. As summarized on line 5 of the exhibit, the variance between the amounts
10 calculated on lines 1 and 3 would yield a reduction to the Company’s proposed
11 revenue deficiency of approximately \$2.7 million: \$1.2 million for the return on
12 rate base, \$0.5 million for depreciation expense, and approximately \$1.0
13 million for property tax expense.

14

15 **Q14. Does this conclude your rebuttal testimony?**

16 A14. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In 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

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss.
COUNTY OF WAYNE)

ESTELLA R. BRANSON states that on September 12, 2025, she served a copy of DTE Electric Company's Rebuttal Testimony and Exhibits of Witnesses, Steven B. Ambrose, Marco A. Bruzzano , Shawn D. Burgdorf, Rodrigo Cejas Goyanes, Bill Chiu, Michael S. Cooper, Jeffrey C. Davis, Jason D. De Stigter, Matthew A. Fix, Neal T. Foley, Margaret E. Guillaumin, Christopher J. Hartley, Brian L. Hill, Allen J. Kryscynski, Timothy J. Lepczyk, Joyce E. Leslie, Markus B. Leuker, Timothy S. Lyons, David C. Milo, Jennifer E. Nelson, Stephen P. Rademacher, Joseph E. Robinson, Akarsh Sheilendranath, Jason E. Sparks, Rachel C. Steudle, Ryan M. Stowe, Anthony Turner, Theresa M. Uzenski, Kirk M. Vangilder, Aaron Willis, and Sherri L. Wisniewski in the above captioned matter, via electronic mail and secure portal links, upon the persons listed on the attached service list and Mr. DeStigter's confidential rebuttal testimony; Ms. Guillaumin's confidential rebuttal testimony; Mr. Stowe's CEII confidential rebuttal testimony, Exhibit A-50 CEII confidential Sch QQ4; Mr. Rademacher's Exhibit A-53, confidential Schedules TT5, TT6 and TT12 were filed under seal with the Commission.

**Estella R.
Branson**

ESTELLA R. BRANSON

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