

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of
DTE Electric Company to increase its Case No. U-21534
rates, amend its rate schedules and Volume No. 4
rules governing the distribution and
supply of electric energy, and for PUBLIC RECORD
miscellaneous accounting authority.

CROSS-EXAMINATION

Proceedings held via Microsoft Teams in the
above-entitled matter before Sally L. Wallace, J.D.,
Administrative Law Judge with MOAHR, for the Michigan
Public Service Commission, Lansing, Michigan, on
Friday, September 64, 2024, at 9:14 a.m.

APPEARANCES:

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On behalf of Michigan Environmental Council,
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22 - - -

23 REPORTED BY: Lori Anne Penn, CSR-1315

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<u>NUMBER</u>	<u>DESCRIPTION</u>	<u>OFRD</u>	<u>RECD</u>
MEC-39	Discovery MNSCDE-17.18	1110	1112
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MEC-61	Discovery MNSCDE-18.17	896	896
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Friday, September 6, 2024

At 9:14 a.m.

- - -

(Hearing resumes following adjournment of Thursday,
September 5, 2024.)

JUDGE WALLACE: O.K. We are back on the
record in Case No. U-21534, In the matter of the
application of DTE Electric 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. I'm Sally Wallace,
the Administrative Law Judge assigned to hear this
matter.

Let's begin with appearances.

Ms. Johnson-Bacon.

MS. JOHNSON-BACON: Good morning, your
Honor. Paula Johnson-Bacon appearing on behalf of DTE
Electric Company. Also joining me today is Jon
Christinidis and Andrea Hayden.

JUDGE WALLACE: Good morning,
Ms. Johnson-Bacon. Mr. Orris.

MR. ORRIS: Good morning, your Honor.
Assistant Attorney Generals Michael Orris, Heather
Durian, and Amit Singh on behalf of the Public Service
Commission Staff.

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1 JUDGE WALLACE: Good morning, Mr. Orris.
2 Mr. Moody.

3 MR. MOODY: Good morning, your Honor.
4 Michael Moody on behalf of Attorney General Dana Nessel.

5 JUDGE WALLACE: Good morning, Mr. Moody.
6 Mr. Bzdok or Ms. Andrews.

7 MR. BZDOK: Good morning, your Honor.
8 Christopher Bzdok and Tracy J., T.J. Andrews on behalf of
9 the Michigan Environmental Council, Natural Resources
10 Defense Council, Sierra Club, and Citizens Utility Board
11 of Michigan.

12 JUDGE WALLACE: Good morning.
13 Mr. Abrams.

14 MR. ABRAMS: Good morning, your Honor.
15 Daniel Abrams appearing on behalf of the Ecology Center,
16 the Environmental Law & Policy Center, the Union of
17 Concerned Scientists, and Vote Solar, collectively the
18 Clean Energy Organizations.

19 JUDGE WALLACE: Good morning, Mr. Abrams.
20 Mr. Ooms or Mr. Lundgren or Ms. Chappelle. (No
21 response.)

22 Mr. Boehm. (No response.)

23 COURT REPORTER: I thought I saw him on
24 earlier.

25 JUDGE WALLACE: I thought I saw him, too.

1 Mr. Boehm, if you're here, you might be muted.

2 All right. Ms. Brader or Ms. Jackson.

3 MS. JACKSON: Morning. Valerie Jackson
4 on behalf of the City of Ann Arbor.

5 JUDGE WALLACE: Good morning,
6 Ms. Jackson. Mr. Templeton.

7 MR. TEMPLETON: Good morning, your Honor.
8 Mark Templeton of the Abrams Environmental Law Clinic
9 appearing on behalf of Soulardarity and We Want Green,
10 Too, known as the Detroit Area Advocacy Organizations in
11 this proceeding. Also entering an appearance on behalf
12 of my colleague Jacob Schuhardt. Thank you, your Honor.

13 JUDGE WALLACE: Good morning,
14 Mr. Templeton. Ms. Horne.

15 MS. HORNE: Good morning, your Honor.
16 Melissa Horne on behalf of Walmart, Inc.

17 JUDGE WALLACE: Good morning, Ms. Horne.
18 ABATE indicated earlier that they will not be attending
19 today. Mr. Vijaykar. (No response.)

20 Ms. Flower.

21 MS. FLOWER: Good morning, your Honor.
22 Olivia Flower here on behalf of ITC Transmission, and
23 entering appearances on behalf of my colleagues Rick
24 Aaron, Hannah Buzolits, and Courtney Kissel.

25 JUDGE WALLACE: Good morning.

1 Mr. Bright.

2 MR. BRIGHT: Good morning, your Honor.
3 Stephen Bright On behalf of Electrify America, LLC.
4 Thanks.

5 JUDGE WALLACE: Good morning, Mr. Bright.
6 And I think Mr. Keskey indicated yesterday that they
7 would be attending the bind-in.

8 Did I miss anybody who would like to
9 place an appearance on the record? (No response.)

10 O.K. Off the record for just a second.

11 (At 9:18 a.m., brief off-record discussion.)

12 JUDGE WALLACE: Back on the record.
13 Ms. Johnson-Bacon, please call your witness.

14 MS. JOHNSON-BACON: Good morning, your
15 Honor. The Company calls Shannen M. Hartwick. Ms. Penn,
16 would you swear the witness.

17 - - -

18 S H A N N E N M. H A R T W I C K
19 was called as a witness on behalf of DTE Electric Company
20 and, having been duly sworn to testify the truth, was
21 examined and testified as follows:

22 DIRECT EXAMINATION

23 BY MS. JOHNSON-BACON:

24 Q Good morning, Ms. Hartwick. Would you please state your
25 name and business address for the record?

Penn Reporting, LLC - lori.penn@yahoo.com

1 A Shannen M. Hartwick, One Energy Plaza, Detroit, Michigan
2 48226.

3 Q Did you file with the Commission a document entitled the
4 Qualifications and Revised Direct Testimony of Shannen M.
5 Hartwick, consisting of a cover sheet and 193 pages of
6 questions and answers?

7 A Yes.

8 Q Do you have any changes you wish to make today to your
9 revised direct testimony?

10 A No.

11 Q Is that, then, the revised direct testimony that you're
12 adopting today?

13 A Yes.

14 Q Are you sponsoring any exhibits associated with your
15 revised direct testimony?

16 A Yes.

17 Q For purposes of identification, are these 12 direct
18 exhibits designated as Exhibit A-12 Schedule B5.4,
19 consisting of 26 pages; Exhibit A-12 Schedule B5.4.1,
20 consisting of five pages; Exhibit A-12 Schedule B5.4.2,
21 consisting of four pages; Exhibit A-12 Schedule B5.4.3,
22 consisting of five pages; Exhibit A-12 Schedule B5.4.4,
23 consisting of six pages; Exhibit A-12 Schedule B5.4.5,
24 consisting of five pages; Exhibit A-12 Schedule B5.4.6,
25 consisting of five pages; Exhibit A-12 Schedule B5.4.7,

1 consisting of four pages; Revised Exhibit A-12 Schedule
2 B5.4.9, consisting of seven pages; Exhibit A-19, Schedule
3 I1.1, consisting of three pages; Exhibit A-19 Schedule
4 I1.2, consisting of one page; and Exhibit A-23, Schedule
5 M7, consisting of 222 pages?

6 A Yes.

7 Q Were these exhibits prepared by you or at your direction?

8 A Yes.

9 Q Do you have any changes you wish to make to any of these
10 12 direct exhibits?

11 A No.

12 Q Did you also file with the Commission a document entitled
13 the Rebuttal Testimony of Shannen M. Hartwick, consisting
14 of a cover sheet and 37 pages of questions and answers?

15 A Yes.

16 Q Do you have any changes you wish to make to your rebuttal
17 testimony today?

18 A No.

19 Q Is that, then, the rebuttal testimony that you're
20 adopting today?

21 A Yes.

22 Q Are you sponsoring any exhibits associated with your
23 rebuttal testimony in this case?

24 A Yes.

25 Q For purposes of identification, are those two rebuttal

1 exhibits designated as Exhibit A-53 Schedule RR-1,
2 consisting of seven pages; and Exhibit A-53, Confidential
3 CEII Protected Schedule RR-2, consisting of one page and
4 one Microsoft Excel file?

5 A Yes.

6 Q Were these exhibits prepared by you or at your direction?

7 A Yes.

8 Q Do you have any changes to make to any of these two
9 rebuttal exhibits?

10 A No.

11 MS. JOHNSON-BACON: Your Honor, DTE
12 Electric moves to bind into the record the
13 Qualifications, Revised Direct Testimony, and Rebuttal
14 Testimony of Shannen M. Hartwick, and for admission at
15 the end of cross-examination of the aforementioned
16 exhibits, and tenders Ms. Hartwick for cross-examination.

17 JUDGE WALLACE: Thank you,
18 Ms. Johnson-Bacon. Is there any objection to binding in
19 the revised direct testimony of Ms. Hartwick?

20 Hearing none, the testimony is bound in.

21 Is there any objection to binding in the
22 rebuttal testimony of Ms. Hartwick?

23 Hearing none, the testimony is bound in.

24 (Testimony bound in.)

25 - - -

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-21534

QUALIFICATIONS
AND
REVISED DIRECT TESTIMONY
OF
SHANNEN M. HARTWICK

DTE ELECTRIC COMPANY
QUALIFICATIONS AND REVISED DIRECT TESTIMONY OF SHANNEN M.
HARTWICK

Line
No.

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

2 A1. My name is Shannen M. Hartwick (she/her/hers), and my business address is One
3 Energy Plaza, Detroit, Michigan, 48226. I am employed by DTE Electric Company
4 (DTE Electric, DTEE or Company).

5

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

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

8

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

10 A3. I graduated from the University of Michigan with a Bachelor of Science in
11 Engineering in 2007 and completed the Executive MBA program with the Ross
12 School of Business at the University of Michigan in April 2023.

13

14 **Q4. Please summarize your professional experience.**

15 A4. I began my career with DTE Electric in 2008 and have been employed there since.
16 I started out as an Associate Engineer in the Performance Management group where
17 I worked on several process improvement projects across Distribution Operations.
18 Over the years, I held a number of positions with increasing leadership
19 responsibilities primarily within Distribution Operations and spent a year in DTE
20 Electric's strategy team. Within Distribution Operations I worked in areas that
21 include: Process Management Team, Substations, Asset Optimization (System
22 Operations Center, Strategy, and dispatch), Southeast Service Operations and Tree
23 Trim.

24

Line
No.

1 In 2014, I took a position as a Developmental Field Supervisor – Southeast Service
2 Operations where I was responsible for leading the frontline lineman performing
3 maintenance, operations, and construction on DTE Electric’s electrical distribution
4 system.

5
6 In 2015, I was promoted to Manager – Tree Trim where I was responsible for
7 leading Operations for the Tree Trim Team, comprised of DTE Energy Employees
8 and all six of our tree trim vendors (comprising over 1300 tree trimmers in 2022).
9 In this role, I was responsible for safety, quality, productivity, customer
10 satisfaction, storm and trouble restoration efforts, and relationships with
11 municipalities.

12
13 In 2020, I was promoted to the Director of Tree Trim where I was responsible for
14 the strategy and execution of the Tree Trim Program. This included contract
15 negotiations, strategy, planning, auditing, execution, outage restoration trimming,
16 customer satisfaction, tree trim technology, and scheduling.

17

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

20 A5. Yes. I am a Lean Six Sigma Blackbelt.

21

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

23 A6. Currently, I am the Director of Automation. In this role, I am responsible for the
24 execution of the distribution automation work. This includes overseeing

Line
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1 automation program strategy and budget, engineering and planning, scheduling,
2 construction, and in-servicing commissioning.

3

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

6 A7. Yes. I sponsored testimony in Case numbers. U-20836 and U-21297. In addition,
7 I supported the preparation of testimony on the topic of the Company's tree
8 trimming program in previous rate cases (Case Nos. U-20162 and U-20561).

Line
No.

1 **Purpose of Testimony**

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

3 A8. The purpose of my testimony is to support, as reasonable and prudent, the historical
4 capital expenditures for 2022, projected capital expenditures for 2023 through
5 December 31, 2025, in the distribution strategic investment category of the
6 Technology and Automation Pillar, and the programs associated with the
7 Company's Infrastructure Recovery Mechanism (IRM).

8

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

10 A9. Yes. I am sponsoring portions of Exhibit A-12 Schedule B5.4, Exhibit A-23
11 Schedule M7, and all of Exhibit A-19 as follows:

12

13	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
14	A-12	B5.4	Projected Capital Expenditures, Distribution Plant –
15			Technology and Automation (pg. 1-2,17-26)
16	A-23	M7	Distribution Plant Capital Project Detail –
17			Technology and Automation
18	A-12	B5.4.1	Pilots: NWA: O'Shea Energy Storage
19	A-12	B5.4.2	Pilots: NWA: Battery Trailer
20	A-12	B5.4.3	Pilots: NWA: Omega Load Relief
21	A-12	B5.4.4	Pilots: NWA: Fisher Load Relief
22	A-12	B5.4.5	Pilots: NWA: Port Austin Load Relief
23	A-12	B5.4.6	Pilots: NWA: Veridian
24	A-12	B5.4.7	Pilots: NWA: EV Charging Demonstration at ACM
25	A-12	B5.4.9 Revised	Pilots: NWA: Adaptive Networked Microgrids

Line
No.

1 A-19 I1.1 Telecom Reliability

2 A-19 I1.2 Telecom Cost

3

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

5 A10. Yes, they were.

6

7 **Q11. How is your testimony organized?**

8 A11. My testimony consists of the following parts:

9 Part I – Infrastructure Recovery Mechanism (IRM) Support

10 Part II – Grid Automation

11 A. Distribution Automation

12 B. Grid Automation Telecommunications

13 C. Conservation Voltage Reduction and Voltage/VAR (Volt-Amps Reactive)
14 Optimization (CVR/VVO)

15 D. Non-Wire Alternative (NWA) Pilots

16 E. Grid Edge Insights and New Technology

17 F. Distribution Line Sensors

18 Part III – Operational Technology

19 G. Grid Management

20 H. Distribution Planning

21 I. Work Management and Scheduling

22 J. Asset Management

23 K. Mobile Technology

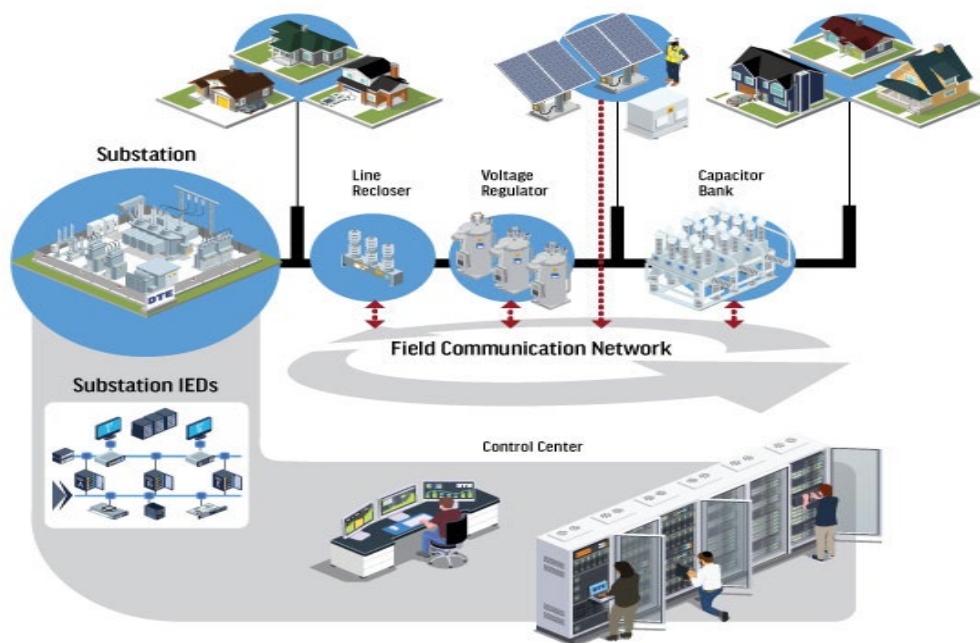
24

25 **Q12. Can you please describe the Technology & Automation Pillar?**

Line
No.

1 A12. Inherent to grid modernization, new technologies are becoming an increasingly
2 fundamental part of the grid, improving the way modern electric grids operate and
3 resulting in improved reliability, operability, and safety. Investments in technology
4 also provide new opportunities to improve operations in ways that benefit
5 customers, such as the ability to automatically isolate outages to limit the number
6 of impacted customers. An additional critical function is to provide real-time
7 visibility for system operators and engineers into circuit and substation loading.
8 This loading data is critical to managing circuits efficiently both today and in the
9 future, and to accommodating electric vehicles and increasing numbers of
10 Distributed Energy Resources (DER) such as solar, and energy storage. A modern
11 distribution system overview can be seen in the figure below.

Figure 1 Modern Distribution Overview



Line
No.

1 **Q13. What categories of investments make up the Technology and Automation**
2 **Pillar?**

3 A13. This pillar consists of the Grid Automation and Operational Technology categories.
4 Grid Automation covers four key areas: Distribution Automation, Grid Automation
5 Telecommunications, Conservation Voltage Reduction (CRV/VVO), and Non-
6 Wire Alternatives (NWA) pilots. Operational Technology covers five key areas:
7 Grid Management, Distribution Planning, Work Management and Scheduling,
8 Asset Management, and Mobile Technology. These are discussed later in
9 testimony.

10

11 **Q14. Do Grid Automation and Operational Technology (OT) work independently**
12 **of each other?**

13 A14. No, OT is a set of enabling technologies that interact closely with Grid Automation
14 and are tailored to support its objectives where needed within the Automaton
15 roadmap.

16

17 **Infrastructure Recovery Mechanism (IRM) Support**

18 **Q15. Are any of the programs you are supporting impacted by the Company's**
19 **Distribution Infrastructure Recovery Mechanism (Distribution IRM or**
20 **IRM)?**

21 A15. Yes, as described by Company Witness Foley in his testimony, in the
22 Commission's December 1, 2023 Order in Case No. U-21297 (December 2023
23 Order) it authorized IRM treatment for the 4.8 kV Circuit Automation program
24 from December 1, 2023 through the end of 2025.

Line
No.

1 **Q16. Is the Company proposing recovery of any additional automation investment**
2 **during the bridge and/or test years beyond what the Commission previously**
3 **authorized for recovery through the IRM?**

4 A16. Yes, as reflected in Exhibit A-12, Schedule B5.4, Page 17, Line 2, the Company is
5 proposing recovery on an additional \$21.2 million of Distribution Automation
6 investment in 2024 and an additional \$125.6 million of Distribution Automation
7 investment in 2025. This investment is incremental to the automation investment
8 already authorized for IRM treatment during these years and will support wholly
9 different work to avoid double recovery of the same investment.

10

11 **Q17. Is the Company proposing recovery for any additional automation investment**
12 **through the IRM beyond the test year of this case?**

13 A17. Yes, as described by Company Witness Foley, the Company is proposing a two-
14 year extension of the IRM (i.e., calendar years 2026 and 2027). As part of that
15 extension the Company is proposing recovery of additional Distribution
16 Automation capital investment as captured in Exhibit A-33, Schedule X1.

17

18 **Q18. Is the Company proposing any modifications to the scope of the automation**
19 **investment authorized for IRM treatment?**

20 A18. Yes, as part of the proposed two-year IRM extension described by Company
21 Witness Foley, the Company is proposing that the scope of the automation
22 investment change from “4.8 kV Circuit Automation” to “Distribution
23 Automation”. This change reflects the Company’s strategy to fully automate the
24 distribution grid to provide safety and reliability benefits to customers. The is
25 discussed in more detail in later in my testimony, questions 29 and 30.

Line
No.

1 **Grid Automation**

2 **Q19. What is Grid Automation?**

3 A19. Grid Automation is focused on the physical technology infrastructure needed to
4 support the efficient control and operation of a modern distribution grid. These
5 investments include reclosers to improve safety and reliability, capacitors and
6 voltage regulation for CVR/VVO, infrastructure to support NWA, DER, EVs, and
7 grid telecommunications.

8

9 **Q20. Why is investing in Grid Automation essential for the customers of DTEE?**

10 A20. Grid Automation is essential for DTEE to improve grid reliability, provide an
11 enhanced customer experience, facilitate grid planning, and support integration of
12 DERs. The distribution grid is increasing in complexity as the result of growing
13 bi-directional flow of power from the integration of renewable resources. Grid
14 automation improves the reliability of the power grid by enabling real-time
15 monitoring, control, and quick response to faults and abnormalities. It reduces
16 outage durations, improves fault detection, and enhances grid resilience. Grid
17 automation plays a crucial role in managing the variability and intermittency of
18 renewable energy generation. It enables the ability to balance supply and demand,
19 optimize energy flows, ensure grid stability, and facilitates the seamless integration
20 of renewable energy into the grid. Grid Automation also provides valuable data
21 and insights for grid planning and expansion. With automation, DTEE can adapt
22 to changes in energy generation and consumption patterns, better accommodate the
23 load growth from electric vehicles and integrate other new technologies into the
24 grid. This flexibility ensures the grid can meet future energy demands and
25 technological advancements.

Line
No.

1 **Q21. Where are the details of the capital investment in this category?**

2 A21. The details of the capital investment in this category are included in:

3 Exhibit A-12, Schedule B5.4, page 17-18

4 Exhibit A-23, Schedule M7

5

6 **Table 1 Grid Automation Exhibit Locations**

Program/Project	Exhibit A-12 Sch. B5.4	Exhibit A-23 Schedule M7	Exhibit A-23 Schedule M8
Distribution Automation	p. 17, line 2	pp. 46-49	pp. 136, 138-139
Grid Automation Telecommunications	p. 17, line 6	pp. 74-77	pp. 136, 140-142
CVR/VVO	p. 17, line 8	pp. 34-37	pp. 136, 142
NWA: O'Shea Energy Storage	p. 17, line 9	pp. 142-145	pp. 136, 142-143
NWA: Battery Trailer	p. 17, line 10	pp. 125-128	pp. 136, 142-143
NWA: Omega Load Relief	p. 17, line 11	pp. 138-141	pp. 136, 142-143
NWA: Fisher Load Relief	p. 17, line 12	pp. 134-137	pp. 136, 142-143
NWA: Port Austin Load Relief	p. 17, line 13	pp. 146-149	pp. 136, 142-143
NWA: Veridian	p. 17, line 25	pp. 154-157	pp. 136, 142-143
EV Charging Projects	p. 17, line 28	pp. 129-133	pp. 136, 142-143
NWA: Adaptive Networked Microgrids	p. 17, line 26	pp. 120-124	pp. 136, 142-143
Grid Edge Insights & New Technology	p. 17, line 30	pp. 78-82	pp. 137, 143
DER Control	p. 18, line 31	pp. 38-41	pp. 137, 143
NWA: Small Solar and Storage Testbed	p. 17, line 14	pp. 150-153	pp. 137, 143
Sensor, Network and Algorithm Development (Solar Deployment)	p. 17, line 15	pp. 181-184	pp. 137, 143
Distribution Sensing and Monitoring (inclgd Line Sensors)	p. 17, line 7	pp. 54-57	N/A

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1 **A. Distribution Automation**

2 **Q22. What is Distribution Automation?**

3 A22. Distribution Automation (DA) uses digital sensors and switches with advanced
4 control and communication technologies to automate feeder switching, monitor
5 voltage and equipment health, and manage voltage and reactive power. Automation
6 improves the speed, cost, and accuracy of these key distribution functions to deliver
7 reliability improvements and cost savings to customers. This technology plays a
8 crucial role in modernizing the power grid, as evidenced by The Department of
9 Energy (DOE) report *Distribution Automation: Results from the Smart Grid*
10 *Investment Grant Program*¹,” published in September 2016.

11

12 **Q23. What are the benefits of Distribution Automation?**

13 A23. The benefits include: improved distribution system resilience to extreme weather
14 which can limit the number of customer outages; improved Fault Location,
15 Isolation, and Service Restoration capabilities which improve customer restoration;
16 more effective equipment monitoring and preventative maintenance to prevent
17 equipment failures; more efficient use of repair crews; reduced repair times; and
18 improved grid integration of DER.

19

20 The Distribution Automation technologies and Smart Grid Investment Grant
21 Projects discussed by the DOE in a 2016 report on the benefits of distribution
22 automation begin to quantify how these technologies can substantially benefit the
23 grid. After deploying distribution automation programs, five utilities reported a 50-

¹ Office of Electricity Delivery and Energy Reliability. (2016). *Distribution Automation: Results from the Smart Grid Investment Program*. U.S. Department of Energy.
energy.gov/sites/prod/files/2017/01/f34/Final_SGIG_Report_-_2016-12-20_clean.pdf

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1 55% reduction in the number of customer interruptions and customer minutes of
2 interruptions per outage events, while three utilities reported System Average
3 Interruption Frequency Index (SAIFI) improvements of 17-58% from pre-
4 deployment baselines due to the ability to more quickly identify the location of a
5 fault and perform switching activities that allow the fault to be isolated to a smaller
6 area so that fewer customers are impacted during the repair activities. The real-
7 world examples provided by the DOE in this study demonstrate that DTE Electric
8 specific Distribution Automation circuit and program benefits, such as the SAIDI
9 reduction of 54 minutes over 2024 and 2025, covered later are achievable.²
10 (Distribution Automation: Results from the Smart Grid Investment Grant Program
11 (energy.gov)).

12

13 Distribution Automation, which includes automated field devices, advanced
14 protection, and SCADA, is a core component for grid modernization. Distribution
15 Automation provides immediate system reliability benefits and adds the core
16 components to support potential future grid needs.

17

18 **Q24. What are the core investments the company is deploying to achieve these**
19 **benefits?**

20 A24. The Distribution Automation Program is primarily composed of pole top recloser
21 deployments. Pole top reclosers, such as the G&W Electric's Viper recloser used
22 in this program, offer a variety of capabilities needed for distribution automation
23 such as the ability to isolate outages into smaller sections and the ability to reroute
24 power around damage. Reclosers installed at midpoints on a circuit will operate

² See footnote 1.

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1 when a fault is detected and isolate the outage to smaller area, impacting less
2 customers. Reclosers installed at a tie point on the end of a circuit provide the
3 ability to reconfigure circuits and reroute power around damaged sections by
4 connecting to adjacent circuits. This device is also used to provide advanced
5 protection capabilities, such as ground detection and isolation, which are covered
6 in more detail in question 26. The pole top devices also provide circuit level
7 SCADA monitoring and control to the System Operations Center. Beyond the pole
8 top reclosers, some general distribution construction may be needed to create tie
9 points on distribution circuits and to support capacity and voltage during
10 reconfiguration.

11

12 **Q25. Does DTEE have any unique considerations informing the development of its**
13 **Distribution Automation strategy?**

14 A25. DTEE has two unique considerations that were important when evaluating
15 Distribution Automation on the Company's distribution system. The first of these
16 is the nature of the ungrounded 4.8 kV delta system. This consideration is unique
17 as most utilities no longer have this type of lower voltage ungrounded system to
18 consider. Distribution Automation will improve ground detection and isolation,
19 thus reducing the risk of energized down wire on the ungrounded 4.8 kV system.
20 The ground detection functionality adds improved safety factors to the traditional
21 reliability improvement from Distribution Automation. The second consideration
22 is that service restoration benefits identified in Distribution Automation require a
23 level of circuit connectivity and capacity beyond what DTEE has in some areas of
24 the distribution grid. Circuits with existing connections that need only automation
25 equipment installed will be targeted earlier in this process, while circuits requiring

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1 new connectivity or additional capacity are prioritized later in order to maximize
2 near term benefits for customers.

3

4 **Q26. What benefits can reclosers provide in terms of ground detection and**
5 **isolation?**

6 A26. A ground on a circuit is a potential indicator of an energized wire-down condition
7 that in some circumstances could pose a safety hazard to the public. The
8 Distribution Automation Program includes start of circuit reclosers that provide
9 new capability to detect when a ground occurs on a circuit as well as the ability to
10 isolate the grounded circuit. Currently, when a ground alarm appears on a circuit,
11 a substation operator is dispatched to the substation and manually identifies which
12 circuit has a ground, then a field crew is sent to locate the ground and isolate. With
13 the ability to automatically identify this condition, the hazard can be detected and
14 deenergized much more quickly and efficiently through automated isolation,
15 quickly eliminating the risk associated with the downed wire. Addressing these
16 hazards automatically not only reduces the safety risk sooner but allows resources
17 previously used to isolate energized wire downs to be directed to restoration
18 activities. This grid improvement is accomplished by installing start of circuit
19 reclosers across all circuits fed from the same substation transformer and
20 programming these reclosers using timing coordination between the circuits.
21 Under this structure, when a ground occurs on one of the circuits from that
22 substation transformer, all of the circuits detect the ground. This trigger
23 programmed timing coordination of the reclosers, where each recloser operates in
24 sequence until the circuit with the ground is detected and isolates that individual
25 circuit. As a result, potentially energized wire downs are isolated and deenergized

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1 very quickly. These benefits will apply to all circuits being automated in 2024 (95
2 circuits), which currently see an average of 16 downed wires per year, and to the
3 149 4.8 kV circuits being automated in 2025, which currently see an average of 17
4 downed wires per year.

5

6 **Q27. Are the technology investments for the Distribution Automation Program the**
7 **same for all circuits?**

8 A27. No. To achieve the service restoration capabilities associated with FLISR, an
9 alternative source of power from adjacent circuits with capacity for additional load
10 needs to be available. Approximately half (48%) of DTEE's distribution circuits
11 already have these connection points established and have the ability to provide
12 sufficient capacity to allow service restoration during an outage event. An
13 additional 40% of circuits either require some investment to establish connection
14 points or require detailed evaluation to determine if investment is needed to
15 increase emergency capacity needed to support service restoration. The remaining
16 12% of circuits have physical restrictions such as lakes, rivers, freeways, or service
17 territory boundaries that may make establishing connections with adjacent circuits
18 difficult. The estimated benefits of tie locations are also adjusted to account for
19 catastrophic storm conditions during which both circuits may be impacted, thereby
20 reducing the benefits. This condition is addressed through a reduction to overall
21 benefits of the Distribution Automation Program rather than on an individual circuit
22 basis.

23

24 **Q28. What factors inform the Company's prioritization for Distribution**
25 **Automation?**

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1 A28. Across Distribution Operations, the Global Prioritization Model (GPM) is used to
2 rank strategic investments; this topic is described further by witness Kryscynski.
3 These factors are what drives Distribution Automation's high GPM ranking: (a) the
4 safety benefits associated with de-energizing down wires, (b) the reliability benefits
5 associated with the reduced number of customer interruptions and the reduction of
6 outage durations, and (c) the improved operational efficiencies associated with
7 improved system monitoring and control. The safety benefit factor applies to all
8 4.8 kV circuits, and special weighting is given to the 4.8 kV circuits that have
9 experienced high levels of wire downs. There are also additional safety benefits
10 for completing all circuits associated with a particular substation transformer to
11 ensure ground isolation coordination. Reliability benefits are estimated at the
12 individual circuit level based on historical reliability and the existing level of
13 automation. The existing level of automation is also key to estimating costs for
14 cost/benefit circuit prioritization. Operational efficiency improvements are
15 universally applied with improvements in safety and reliability.

16

17 **Q29. What is the Company's scope for Distribution Automation?**

18 A29. The scope of Distribution Automation includes: (a) installation of SCADA enabled
19 reclosers on larger circuits with more than 400 customers to have at a minimum of
20 one midline recloser and a SCADA enabled tie point, (b) installation of a recloser
21 near the start of the overhead portion of a circuit for all ungrounded 4.8 kV circuits
22 to enable ground detection and isolation, (c) installation of reclosers near the start
23 of the circuit on 13.2 kV circuits that currently do not have SCADA enabled circuit
24 breakers in the substation, (d) the construction of the necessary overhead equipment
25 to create and enable load shifts between circuits, and, (e) the integration of devices

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1 and technology within ADMS to allow for the application of FLISR with the new
2 and existing devices. The scope will also include ground fault detection and
3 isolation on the 4.8 kV system, SCADA monitoring and control of all general-
4 purpose distribution circuits, and improved fault isolation and increased remote
5 restoration capabilities to improve reliability.

6

7 **Q30. How has this strategy evolved since the Company's previous rate case, Case**
8 **No. U-21297, was filed?**

9 A30. Following the severe storms that impacted the Company's service territory in early
10 2023, a review of the outage events and the duration of restoration concluded that
11 the limited deployment of automation across the electric grid was impeding the
12 Company's ability to restore services to customers swiftly during large storm
13 events. Based on this conclusion, the Company determined that extensive circuit
14 automation was required to improve reliability performance for our customers.

15

16 As part of this expanded focus, the Distribution Automation Program was
17 broadened to encompass the entire distribution grid, including the installation of
18 SCADA-enabled reclosers and enabling remote sectionalization of outages into
19 400-800 customer segments. Additionally, it includes establishing tie points to
20 connect circuits for efficient load shifting.

21

22 Furthermore, the Company recognized that deploying remotely operated SCADA-
23 enabled reclosers on circuits will deliver most of the benefits associated with the
24 substation automation program at a significantly accelerated pace. As a result of
25 this assessment, funding for substation automation was reduced and redirected to

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1 Distribution Automation investments, which also supported greater alignment and
2 bundling opportunity with substation related asset replacement scope of work.

3

4 **Q31. With the expanded scope of Distribution Automation and the refined ability**
5 **to prioritize circuits to automate, will the Company combine 4.8 kV circuit**
6 **automation, 13.2 kV circuit automation, substation automation, and circuit**
7 **rebuild for automation into a single focused distribution automation**
8 **program?**

9 A31. Yes. The Company has developed a cost-benefit model for Distribution
10 Automation that estimates the reliability and safety impact and the investment
11 required for every distribution circuit. This model allows the Company to prioritize
12 circuits across all of the previously individual automation programs. As a
13 fundamental step in the program, standards are being developed for the
14 implementation of automation associated with specific grid voltage. Investment
15 for recloser installations in 2024 will continue to focus on the 4.8 kV distribution
16 system, based on standards and design work that was completed in 2023. The 13.2
17 kV standards for automation are being developed in 2024, which will ensure the
18 2024 design and 2025 construction will be aligned with the updated circuit
19 prioritization model.

20

21 **Q32. How are circuit level benefits estimated?**

22 A32. Distribution Automation circuit level benefits were modelled by reviewing
23 historical reliability performance against expected performance based on
24 installation of Distribution Automation equipment including midpoint reclosers and
25 SCADA enabled tie points. For example, a 4.8 kV circuit without any automation

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1 would have been modeled by reviewing the reliability data for the recent outages
2 and then reviewing what the reliability data would have been after the planned
3 installation start of circuit ground detection recloser, a midpoint recloser and a tie
4 recloser. The operational efficiency benefits provided by automation were
5 estimated and applied to those outages as well as modelled reductions in customers
6 interrupted and outage durations. These reductions were modelled based on
7 automation design requirements and are consistent with the industry performance
8 improvement data seen in the DOE Smart Grid Investment Grant Projects paper
9 discussed earlier. Benefits were not included in this analysis for circuits where
10 automation already exists. The individual circuit costs were estimated by reviewing
11 existing circuit automation and then defining the expected additional equipment
12 needed to achieve the modelled benefits.

13

14 **Q33. What is the scope of the Distribution Automation Plan for 2024 and 2025?**

15 A33. The 2024 Distribution Automation Plan is composed of the investments included
16 in the IRM in Case No. U-21297, which is 63 circuits and 189 reclosers, plus an
17 additional 96 reclosers that are expected to improve 32 circuits on the 4.8 kV
18 distribution system. In addition, engineering and design work will be completed
19 in 2024 for 240 reclosers covering approximately 80 circuits to be constructed in
20 2025. In 2025, 578 reclosers across an estimated 242 circuits will be constructed
21 based on the prioritization model developed in 2023 and 480 reclosers and 160
22 circuits are expected to undergo engineering and design in 2025 for 2026
23 construction.

24

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1 **Q34. What benefits are associated with the Distribution Automation investments**
2 **planned for 2024 to 2025?**

3 A34. The planned Distribution Automation work for 2024 is expected to address ground
4 detection and isolation for 63 circuits at 18 substations that is part of the IRM, and
5 an additional 32 circuits at 11 substations. It is also expected to reduce SAIDI on
6 impacted circuits by 45%, reducing system SAIDI by 9 minutes, based on the
7 circuit level benefits modeling discussed earlier. The planned work for 2025 is
8 expected to address ground detection and isolation for 281 circuits at 73 substations
9 and is expected to reduce SAIDI on impacted circuits by 47% reducing system
10 SAIDI by 45 minutes.

11

12 **Q35. What progress in Distribution Automation was made in 2023?**

13 A35. In 2023, DTEE completed engineering and design standards for use of the
14 Distribution Automation reclosers for 4.8 kV and initial standards for 4.8 kV
15 ground detection and isolation, ground detection and isolation standards will be
16 finalized in early 2024, based on incorporating process improvements identified
17 during initial deployments. DTEE has field installed 208 reclosers and
18 commissioned 102 more with fault isolation and remote operating capability, with
19 the balance of 106 expected to be commissioned in early 2024. DTEE has also
20 completed circuit level costs and benefits estimates, which will be used for circuit
21 prioritization and program cost benefit estimation.

22

23 **Q36. Has the Company been able to confirm the benefits of the 2023 Distribution**
24 **Automation investments?**

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1 A36. The majority of the 70 reclosers that were installed in 2023 were installed in the
2 second half of the year so a full year of the performance data needed to confirm the
3 estimated benefits is not yet available. DTEE will track performance in two ways
4 to ensure expected benefits are achieved. First, in 2024, DTEE will begin using
5 actual outage data to track estimated customer outage minutes saved by automation.
6 This will ensure that automation is performing as expected during individual
7 events. Second, DTEE will track the performance of Distribution Automation
8 circuits before and after work is complete and will compare the change to the
9 control group. Variance in individual circuit performance year to year can be
10 heavily influence by weather and unique events, but comparing the performance of
11 the larger group of automation circuits relative to the rest of the system can provide
12 the validation of program level objectives.

13

14 **B. Grid Automation Telecommunications**

15 **Q37. What is Grid Automation Telecommunications?**

16 A37. Grid Automation Telecommunications refers to the use of telecommunications
17 technology in the automation of electrical power grids. It involves the integration
18 of communication systems with power distribution networks to enable real-time
19 monitoring, control, and management of grid operations. The telecommunications
20 network is the backbone system that connects the distribution automation
21 equipment in the field to the ESOC, enabling two-way remote monitoring and
22 control that provides visibility into grid conditions and allowing the ESOC to
23 remotely operate grid devices. An advanced telecommunications infrastructure
24 plays a crucial role in grid automation by providing reliable and secure
25 communication channels for data exchange between various grid devices such as

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1 sensors, meters, switches, and control centers. Telecommunication networks have
2 always played an important role in supporting the safe and reliable delivery of
3 electric power. This role is becoming even more crucial in the looming industry
4 transformation, since Smart Grid represents the convergence of
5 telecommunications, computing, and energy technologies.

6

7 **Q38. Can you describe the structure of a utility telecommunications network?**

8 A38. A utility telecommunications network structure typically consists of various
9 components that work together to facilitate communication and data exchange
10 within the utility's infrastructure. Here are some key elements of an electric utility
11 telecommunications network structure:

- 12 • Backhaul network: The backhaul network serves as the central communication
13 backbone of the utility's infrastructure, connecting different sites, such as power
14 plants, substations, and control centers. It handles high-capacity data transmission
15 and supports critical applications, for monitoring, control and device management,
16 and incorporates the highest level of cyber security controls and network
17 management. Through 2025, the Company's Grid Automation
18 Telecommunications investments are focused on expanding the backhaul network.
- 19 • The last mile network: The last mile network connects end-user devices, such as
20 sensors, meters, and monitoring equipment, to the backhaul network. It enables
21 data collecting, monitoring, and control and the edge of the network. It is made up
22 of wireless technology such as microwave links, radio frequency (RF) networks,
23 and cellular networks, to establish communication links between different sites.
24 Wireless infrastructure provides flexibility and scalability in extending network
25 coverage and provides a secure and manageable interface between devices and the

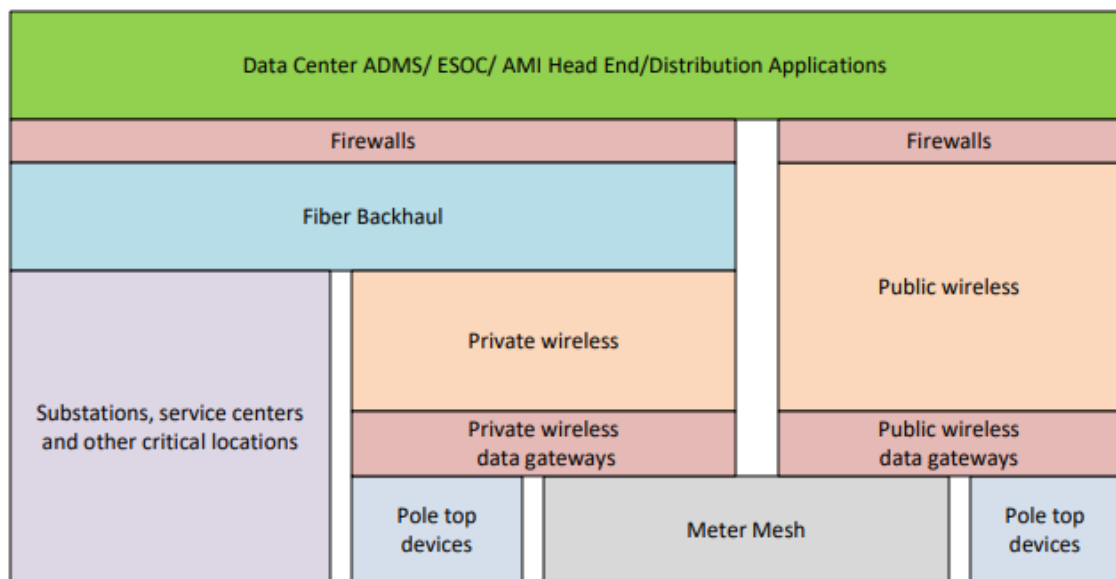
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1 backhaul network. The Company is not making significant investments in this area
2 for the time period of this instant case but plans to in the future.

3
4 The Grid telecommunications network consists of many technologies such as fiber,
5 wireless systems, elevated structures, switches, and routers. Each of these
6 technologies need supporting investment to create an integrated system that allows
7 for the seamless flow of information, enabling remote monitoring and control of
8 the grid and is the mechanism that cybersecurity threat monitoring and security
9 updates are performed. See Figure 2 for a simplified structure of a Grid
10 Telecommunications Network.

11

12 **Figure 2 Simplified Structure of a Grid Telecommunications Network**



13

14 **Q39. Can you describe the existing state of the Company's Grid Automation**
15 **Telecommunication network?**

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1 A39. DTEE's existing telecommunication network consists of a combination of
2 equipment and technologies including fiber, microwave, leased phone lines, and
3 radio; some of these technologies being legacy end of life systems. The current
4 network does not fully connect all field devices to the ESOC, many devices
5 currently on the Company's electrical system, including some pole-top and
6 substation equipment, are either not connected for remote monitoring and control,
7 or are connected through a patchwork of communication networks and technologies
8 that have varying capabilities, are not fully integrated, and in many cases cannot
9 provide resiliency due to their architecture. At the center of the telecommunications
10 system, the Company currently relies on a fiber ring that was originally designed
11 to only connect data centers and transmission stations on towers along transmission
12 corridors. The primary purpose of that connection was to provide a backhaul
13 network enabling resiliency of data flow for critical operations. At the time the fiber
14 ring was installed, the design scope did not include the capability for connecting
15 the more modern distribution resources coming to the grid today, such as the circuit
16 automation devices discussed earlier in this testimony. This portion of the backhaul
17 network does not extend to all critical assets, which is why the Company is
18 investing in expanding the backhaul network with additional fiber. Additionally,
19 the legacy telecommunications technologies lack sufficient capability to provide
20 the bandwidth speed, capability, and reliability necessary to stabilize delivery and
21 response to the data being transmitted by those modern distribution resources and
22 is a key driver of investment in Grid Automation Telecommunications.

23

24 **Q40. What are the other key drivers of the Company's investment in Grid**
25 **Automation Telecommunications?**

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1 A40. The increasing deployment and utilization of grid automation equipment, evolving
2 grid demands, and aging telecommunications infrastructure are the other key
3 drivers of DTEE's investment in grid automation telecommunications.
4 First, in direct support of our distribution automation plan, the Company is
5 increasing the deployment of Distribution Automation and smart devices in the
6 field to drive improvements in grid reliability, resiliency, optimization, and
7 efficiency through programs like Distribution Automation, Conservation Voltage
8 Reduction (CVR), Volt-Var Optimization (VVO), Advanced Metering
9 Infrastructure (AMI), and demand response. These technologies, when deployed
10 on the grid, require real-time data transmission from field devices through a secure
11 channel with sufficient, highly reliable bandwidth. Distribution automation alone
12 plans to add over 13,000 new devices to the network which is over five times more
13 distribution SCADA devices than are currently installed. As noted earlier in my
14 testimony, DTEE is investing in automation devices that are being deployed on the
15 grid to improve reliability. These devices require a telecommunications network
16 that is reliable, secure, and has sufficient bandwidth to transmit data to allow for
17 real-time monitoring and control. The investment in Grid Automation
18 Telecommunications supports DTEE's Distribution Automation devices by
19 providing the advancements in bandwidth, speed, capability, and reliability
20 necessary to operate the modern grid and enable the benefits from the automation
21 devices. These investments provide the necessary infrastructure and capabilities to
22 automate and optimize grid operations and enhance reliability. Every alarm,
23 command, and outage notification seen by the ADMS systems and System
24 Operations Center (SOC) must come through the communications network.

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1 Without these investments, the Company would have to build device
2 communication capacity as automation devices are installed on the grid.

3

4 Secondly, the increasing adoption of customer owned renewable energy sources is
5 driving the need for integration and management of those sources to enable
6 operators to monitor and control the flow of renewable energy. This control
7 requires bidirectional information flow between utilities and renewable customers,
8 and real-time communication that supports coordination and optimization of the
9 electrical system. The Company's existing communications network was not
10 designed to include the modern distribution resources coming to the grid, and the
11 deployment of these resources requires additional bandwidth and reliable, quick
12 transmission of data.

13

14 Lastly, some of the existing communications equipment is targeted for replacement
15 due to obsolescence or lack of available spare parts. End of life, and legacy systems
16 that are incapable of supporting new smart grid operations need to be replaced to
17 support remote management of devices and to provide a platform to support the
18 transition of existing communications assets.

19

20 **Q41. What is the Company's investment plan for Grid Automation**
21 **Telecommunications?**

22 A41. DTE Electric's plan is to first expand the backhaul network fiber to provide
23 sufficient bandwidth and high-speed data transmission capability, and then in future
24 years outside of the timeframe of this case, to invest in the last-mile networks by

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1 connecting wireless systems to the fiber network to bring the visibility and control
2 of all devices into the network.

3

4 The near term primary planned investment is expansion of the fiber system through
5 the installation of a series of fiber rings that interconnect the Company's data
6 centers with its distribution and sub transmission stations, service centers,
7 communications towers, power plants, and other critical DTE Electric facilities.
8 This system is designed to provide communications to locations where they are
9 currently not deployed, have degraded service due to obsolete equipment, have
10 incompatible networks and protocols, or are subject to interference or where the
11 bandwidth needs have increased. The investments in the current case will address
12 many of the critical infrastructure sites that can only be served with a fiber
13 deployment.

14

15 The near-term investments in Grid Automation Telecommunications through 2025
16 will build out the critical backbone of the telecommunication network that connects
17 the key infrastructure sites such as substations and other critical facilities to the
18 various data centers. This is the foundational requirement to enable the
19 functionality of the various operational technologies. Beyond 2025, DTE will need
20 to continue to expand the telecommunication network investments to the next tier
21 of locations that are prioritized from a resiliency perspective. Additionally,
22 investments in 2026 and beyond will be structured to support an advanced wireless
23 system that will be overlaid on the fiber backhaul to provide connectivity for pole
24 top and distributed devices including mobile assets that will not be directly
25 connected to fiber. This combined system of fiber and advanced wireless will

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1 provide sufficient capability to support the communications needs of the electrical
2 system for decades to come.

3
4 This time staged deployment of telecommunications investments will provide
5 reliable, high bandwidth, low latency backhaul for the Distribution Automation
6 investments described earlier in this testimony, including SCADA, AMI backhaul
7 data concentrators, asset monitoring sensors, physical security measures and future
8 planned devices to provide control and visibility to the system control center and
9 engineering backend systems.

10

11 **Q42. How will customers benefit from the Company's investment in Grid**
12 **Automation Telecommunications?**

13 A42. Customers will gain significant benefits from the capabilities that Grid Automation
14 Telecommunications will enable for Distribution Automation. Primarily, for the
15 full reliability and operational benefits of Grid Automation investments described
16 earlier in my testimony, including rapid fault location, isolation, and restoration to
17 minimize downtime during outages and ensuring swift detection and response to
18 disturbances on the grid. More details related to the benefits of fault location,
19 isolation and service restoration are described later in the FLISR section of my
20 testimony. Grid Automation Telecommunications will also provide sufficient
21 future capacity as customers add new energy devices such as DER. Additionally,
22 this solution will also improve coordination of DTEE resources by reducing the
23 number of disparate and legacy systems that must be maintained and operated.

24

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1 **Q43. What telecommunication options were considered in choosing the best**
2 **technology investment to support Grid Automation Telecommunications**
3 **backhaul network expansion?**

4 A43. The Company employs multiple technologies in building the Grid Automation
5 Telecommunications Network and all of them have an important place in the
6 overall solution. We do not employ a one technology fits all strategy and for each
7 portion of the network we consider all of the available technologies which include
8 but are not limited to Microwave, Private mesh, Public commercial cellular,
9 WiMAX, Private and public Fiber and private Radio. we even consider options that
10 we have not yet invested in such as Private Cellular. All of these options were
11 examined and in this case for this particular portion of the project and for this usage
12 profile building our private Fiber capability was selected.

13
14 Multiple technology investment options were considered to support Grid
15 Automation Telecommunications backhaul network expansion. The full
16 implementation of communications to all end points will continue to utilize a
17 variety of the available solutions where they are best suited to provide sufficient
18 capability and reliability. Several factors were considered when selecting the
19 backhaul technology to be utilized for the telecommunications, and a qualitative
20 assessment of those factors is included here. The primary factors considered were
21 the ability of the technology to fully serve the bandwidth (amount of data) and
22 latency (delay in transmitting data) needs, and the reliability and the essential
23 cybersecurity characteristics of those systems for providing service to critical sites
24 and infrastructure. On a site-by-site basis, additional considerations for each of the
25 technologies are factored into the decision of which technology to deploy.

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1 Here is a summary of the uses and characteristics of each telecommunication
2 system type evaluated:

3

4 **Public cellular:**

5 **Description:** Cellular technology owned and operated by a third-party
6 telecommunications carrier and located on carrier owned cell phone towers or
7 leased structures.

8

9 **Current utilization:**

- 10 • Short-term deployment where Distribution Automation is needed quickly,
11 and other options are not currently available or cost effective.

12 **Key Considerations:**

- 13 • No quality of service guarantees for uptime or performance; carriers have
14 already demonstrated they will not notify of network downtime including
15 planned maintenance, or unplanned outages. Carrier maintenance, either
16 planned or unplanned, can impact field network communications
17 availability. When these outages occur, they can result in localized or wider
18 ranging gaps service which impacts meter communications effectiveness.
19 DTEE has no input into these outages and so finds it to be prudent to invest
20 in multiple technologies to increase reliability. The timing of these service
21 interruptions has impacts in large storm restoration when DTE is relying on
22 meter information to establish which customers are restored to prioritize
23 crew dispatch. Examples of reliability issues on this type of network are
24 included in Exhibit A-19 Schedule I1.1.

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- 1 • As a customer vs owner, DTEE is unable to configure specific routes
- 2 between devices and set data prioritization policies for utility traffic.
- 3 Prioritization of data relies on a vague tier system that prioritizes traffic with
- 4 no guarantee or insight to analyze the network performance. No visibility
- 5 into the network routing or ability to troubleshoot network connectivity or
- 6 performance problems.
- 7 • Detailed cyber security logging and network traffic analysis is not available,
- 8 requiring the layering of multiple levels of additional security on the traffic
- 9 to encrypt the data which requires additional equipment infrastructure and
- 10 configuration time and labor at each end point.
- 11 • Monthly fees are typically \$25 per month per location and can exceed \$175
- 12 per month for higher bandwidth plans. When considering the 40,000+
- 13 planned locations for automation and AMI backhaul that will be needed for
- 14 Grid Automation the aggregate costs can reach into the hundreds of millions
- 15 of dollars over the life span of the equipment and it is very likely that
- 16 monthly costs will only increase as DTEE bandwidth needs increase and
- 17 other carrier customers demand even more data. Sites that exceed
- 18 bandwidth plans incur overage fees and in some cases the carriers'
- 19 maximum plans are insufficient to support heavy bandwidth use cases like
- 20 physical security cameras.
- 21 • Interference between other network tenants, in shared service areas at the
- 22 edges of the DTEE territory or where municipal utilities have networks
- 23 there are instances where interference has impacted network capabilities
- 24 due to shared spectrum usage.

Line
No.

- 1 • Public carriers upgrade their system frequently, resulting in the removal of
- 2 older hardware. This can cause premature obsolescence of functioning
- 3 utility communications systems. This hardware replacement cycle is not in
- 4 control of the utility and carrier changes in technology have been forced on
- 5 the utility in some cases resulting in thousands of devices going out of
- 6 support well before their end of life, or a complete lack of service. For
- 7 example, prior to the 3G to 4G transition thousands of square miles of the
- 8 service territory in the thumb region were suddenly without service as the
- 9 networks were shut down and sold off because they were not seen as
- 10 profitable in 2017. Overall, the 3G to 4G technology transition required
- 11 DTEE to invest over \$36M to reconfigure its network and reestablish
- 12 communications to metering assets and device at over 2,700 locations, this
- 13 does not include the cost of downtime, or the opportunity cost of applying
- 14 that personnel time and investment to more valuable system enhancements.
- 15 There was nothing wrong or obsolete about the 3G radios being used from
- 16 a technical perspective (in some cases there were better propagation and
- 17 range from the 3G equipment) and those devices could have had a
- 18 substantially longer remaining lifetime before replacement if the network
- 19 backhaul had not been subject to a technology change. These
- 20 reconfigurations cause additional cost to troubleshoot communications
- 21 failures, replace radios, conduct site evaluations to evaluate the replacement
- 22 communication paths. This unplanned obsolescence is not a problem if the
- 23 technology cycle was in control of the utility.
- 24 • Incapable of providing sufficient bandwidth for physical security use cases
- 25 like security cameras.

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- 1 • In areas with sparse or no coverage it is at the carrier's discretion and the
- 2 utility cost to install new infrastructure, meaning that these network
- 3 extensions would have infrastructure buildout costs and additional lease
- 4 costs above and beyond the monthly fees for data.

5

6 **Private Long-Term Evolution (LTE) Cellular:**

7 **Description:**

- 8 • Cellular equipment owned and operated by the Utility.

9 **Current utilization:**

- 10 • Not currently in use by the Company

11 **Key Considerations:**

- 12 • Best use as a last mile solution for distribution automation and DER
- 13 • Requires backhaul to get to data centers but can efficiently leverage the fiber
- 14 investment.
- 15 • Requires investment in radio frequencies.

16

17 **Point-to-Multipoint and Point-to-Point Microwave:**

18 **Current utilization:**

- 19 • Used in spot solutions since it requires detailed pathing studies and
- 20 communicates between specific locations.

21 **Key Considerations:**

- 22 • Existing issues with signal interference caused by new users of the
- 23 frequency allowed by the deregulation of the frequency bands by the FCC,
- 24 limiting the technological capability substantially and exposing the systems
- 25 to excessive interference.

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- 1 • Microwave requires substantially more tower height that is more expensive
- 2 and more difficult to site and permit to allow direct paths to function given
- 3 the higher frequency's inability to penetrate tree cover.

Line
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1 **Wireless mesh:**

2 **Description:**

- 3 • Utility owned radio equipment

4 **Current or optional utilization:**

- 5 • Supplementing the existing wireless mesh is a short-term solution being
6 employed as part of the AMI program.
- 7 • The existing wireless mesh assets will be aligned to the fiber backhaul to
8 improve overall system capability and resiliency.

9 **Key Considerations:**

- 10 • Does not address the backhaul bandwidth and routing issues with the
11 system, or the requirements of grid automation.
- 12 • May be subject to public interference on shared frequencies and limited in
13 power levels which reduces effective range, especially in heavily treed
14 areas.

15

16 **Leased fiber:**

17 **Description:**

- 18 • Fiber lines owned and operated by a third-party vendor.

19 **Current utilization:**

- 20 • In specific locations where fiber is required for out of service territory wind
21 parks, power plants, and facilities.

22 **Key Considerations:**

- 23 • Requires paying a telecom provider to build out the fiber network to provide
24 the required point to point routes for distribution automation and then
25 paying monthly lease and service fees in addition to the build out costs.

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- 1 • Requires negotiating and maintaining many contracts with different
- 2 providers and negotiating to build fiber linkages between different vendors
- 3 to complete the fiber rings needed for resiliency that may not be considered
- 4 shared or beneficial routes by the provider, resulting in the Company
- 5 absorbing the entire cost of construction.
- 6 • Where networks need to connect to provide resiliency, the Company must
- 7 provide the risers, electronics, and routing equipment at these locations to
- 8 ensure isolation of traffic and cyber security, resulting in increased
- 9 infrastructure costs for this aspect of the project over a privately owned
- 10 system that can optimize the locations of these installations and greatly
- 11 simplify the equipment needed.
- 12 • While there may be minor cost savings where the providers have existing
- 13 fiber lines, the Company's experience is that this is more costly by roughly
- 14 30% or more than building the fiber infrastructure efficiently on existing
- 15 DTEE structures.

16

17 **Private, Company-owned fiber:**

18 **Description:**

- 19 • Fiber lines owned and operated by the Utility.

20 **Current utilization:**

- 21 • Existing fiber ring, and previous phases of grid automation
- 22 telecommunications program

23 **Key Considerations:**

- 24 • Privately owned fiber allows for efficient and optimized routes, and
- 25 infrastructure tailored to the utility use cases.

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1 **Q44. Was a best investment option determined for this phase of the project?**

2 A44. Yes, private fiber was determined to be the best investment for the 2024 and 2025
3 project scope for telecommunications backhaul. This does not mean that DTE will
4 be using fiber exclusively for all telecommunications needs and different
5 technology solutions will continue to be evaluated on a case by cases basis for
6 specific locations. Fiber-optic networks offer unmatched bandwidth, speed,
7 reliability, security, suitability for backhaul of other networks, and resilience to
8 interference. Fiber-optic networks provide significantly higher data transmission
9 speeds and bandwidth essential to support grid automation and scalability for the
10 evolving demands of grid modernization initiatives.

11

12 For example, to meet the needs of substation physical security DTEE has already
13 reached the maximum public cellular and pool data plans at some sites on public
14 carriers, including FirstNet. The Company receives several notices a week that
15 specific sites are using too much bandwidth; bandwidth easily provided by fiber
16 and a factor in prioritizing the fiber deployment.

17

18 Fiber infrastructure provides the necessary backhaul for other communications
19 networks, linking towers, base stations, and other access points to the core network.
20 This connectivity is essential for carrying the massive volumes of data generated
21 by devices to their intended destinations. Fiber infrastructure serves as the bedrock
22 for all last mile networks, playing a pivotal role in ensuring their efficiency, speed,
23 and reliability. Fiber-optic cables provide extremely high and consistent bandwidth
24 over long distances compared to traditional copper cables or wireless medium,
25 transmission capability crucial for the seamless functioning of networks. The

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1 inherent stability and low latency of fiber-optic connections ensure consistent and
2 uninterrupted connectivity, indispensable to last mile networks. This reliability is
3 vital for applications that require real-time data transmission, such as internet of
4 things (IoT) devices, autonomous vehicles, and mission-critical communications.
5 Without a robust and extensive fiber optic infrastructure, DTEE would struggle to
6 deliver the high-speed, low-latency, and reliable connectivity demanded by today's
7 digital landscape. Fiber serves as the linchpin that supports and sustains the
8 interconnectedness and seamless operation of all connected technologies.

9

10 A group of internal SMEs discussed the different options and ranked them
11 qualitatively based on several reliability, lifecycle, and initial cost factors. The
12 results of the qualitative analysis can be seen below.

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1

Figure 3 Alternatives Compared Using Reliability Factors

	Public Cellular	Private LTE	Microwave/Wimax	Wireless Mesh	Leased Fiber	Private Fiber
Bandwidth						
Low Latency						
Network Control						
Prioritization and Quality of Service (QoS)						
Security						
Maintenance Window Scheduling						
Disaster Recovery						
Control of Communications During Emergency						
Protection Against Interference and FCC Decisions						

2

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1

Figure 4 Alternatives Compared Using Life Cycle Factors

	Public Cellular	Private LTE	Microwave/Wimax	Wireless Mesh	Leased Fiber	Private Fiber
Ongoing Operating Costs (Excluding Staffing)						
Staffing						
Open Standards						
Technology Availability						
Technology Stability						
Technology Lifespan						

2

3

Figure 5 Alternatives Compared Using Initial Cost Factors

	Public Cellular	Private LTE	Microwave/Wimax	Wireless Mesh	Leased Fiber	Private Fiber
Control of Geography Covered						
Device Deployment Effort						
Installation Cost						

4

5 **Q45. How is fiber more resistant to interference?**

6 A45. Fiber optic cable operates independently of the wireless spectrum, using light
7 signals transmitted through glass fibers rather than the radio frequencies allocated

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1 and regulated by the Federal Communications Commission (FCC). This technology
2 makes fiber impervious to the electromagnetic disruptions that affect wireless
3 transmissions such as electromagnetic radiation, radio waves, electronic devices,
4 and the FCC's spectrum reallocation, a process of redistributing portions of the
5 electromagnetic spectrum for different services or technologies. Immunity to
6 interference and FCC spectrum reallocation is a testament to the resilience and
7 reliability of fiber optics among communication networks, ensuring consistent,
8 high-quality data transmission and uninterrupted communication pathways critical
9 for applications such as telecommunications, internet services, and utility-owned
10 telecom systems. As a specific example, the Ann Arbor microwave was
11 decommissioned and replaced with fiber after it was determined that a major wifi6
12 deployment would introduce substantial radio interference, rendering the
13 microwave system unable to sustain reliable communications. Subsequent
14 evaluation of the wireless traffic in the area indicated that this projection was
15 accurate and that if the microwave had not been replaced with fiber it would have
16 become unusable.

17

18 **Q46. Why would the Company build a private network versus leasing from existing**
19 **fiber providers?**

20 A46. Owning and operating telecommunication systems allows greater control and
21 flexibility over the networks. Unlike relying on leased or third-party systems,
22 utility-owned infrastructure offers customization, scalability, and adaptability
23 tailored to specific operational needs. This level of control is pivotal in integrating
24 diverse technologies including sensors, IoT devices, and advanced monitoring tools
25 essential for effective Distribution Automation and Smart Grid implementations.

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1 Utility-owned telecommunication systems provide enhanced security and
2 resilience. By internalizing these systems, utilities can implement robust
3 cybersecurity measures and ensure reliable communication channels, mitigating
4 cybersecurity vulnerabilities associated with relying on external networks.
5 Ownership of the network topology allows for efficient use of the entire network
6 and eliminates constraints on traffic routing and prioritization. Investing in utility-
7 owned telecommunication systems aligns with long-term cost-effectiveness and
8 reduced recurring lease fees. Ownership reduces dependency on leased lines or
9 external providers, minimizing ongoing operational expenses and providing greater
10 predictability in maintenance and upgrades. Utility-owned telecommunication
11 infrastructure represents a strategic move towards grid modernization and
12 resilience. Lastly, a private network protects DTEE from network blackouts caused
13 by using leased Internet Service Providers that do not build their networks with the
14 same level of resilience that the electric grid requires. This has resulted in a strategic
15 shift in recent years to build networks privately owned and maintained by DTEE to
16 enable the Company to securely control and operate reliable telecommunication
17 systems.

18

19 **Q47. What components of the Grid Automation Telecommunications investment**
20 **plan were completed in 2022 and 2023?**

21 A47. Highlights of 2022 installations include:

- 22 • 220 miles completed.
- 23 • Fiber installations north and south of I-96 on the West side of Detroit
24 and through Wayne County brought fiber to multiple service centers
25 and backhaul towers, and substation locations.

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- 1 • Installation and commissioning of a fiber route through Pontiac and
- 2 adjacent areas north of the city.
- 3 • Significant work was started on the fiber line from Dearborn to Monroe
- 4 and aligned with the telecommunications changes needed for the
- 5 Trenton Channel Power plant decommissioning work.
- 6 • A major route was started to close a major gap in the existing fiber ring
- 7 between M-53 in Macomb County and the Blue Water Energy Center.

8 **2023 installations included:**

- 9 • 239 miles completed.
- 10 • Completion and commissioning of the Dearborn to Monroe fiber line
- 11 and the connection of both Fermi and Monroe power plant stations and
- 12 facilities to the fiber network, including the Newport service center and
- 13 substation locations.
- 14 • Substantial completion of routes on the East side of Detroit and up the
- 15 I-94 corridor.
- 16 • Additional work nearing completion from 2023 are routes to reach
- 17 Howell service center and the completion of the fiber ring from Monroe
- 18 to Ann Arbor to provide resiliency to the Dearborn to Monroe line.

19

20 **Q48. What investments are included in the 2024 and 2025 telecommunications**
21 **investment plans?**

22 A48. The major routes planned for completion in 2024 and 2025 are those in Detroit to
23 serve all substations and communications towers. This work is being coordinated
24 with the Infrastructure Resilience and Hardening Pillar as well as the City of Detroit
25 Infrastructure (CODI) program.

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1 **2024:**

- 2 • 150 miles in 2024 will provide a southern thumb ring running east to west
3 north of I-69, and a route south of I-94 and Metro Airport to connect
4 substations in the southwest region of the territory. The rest of the 2024
5 investment in fiber installation will be to install taps and entrances to
6 substations from previously constructed routes.
- 7 • Installation of routing electronics to light up routes that have finished fiber
8 construction and to connect substation end point taps with the existing
9 wireless mesh network end points to improve bandwidth and reliability.
10 This work will continue into 2025.

11 **2025:**

- 12 • Routes for 2025 will include investments to replace leased lines in the
13 Eastern thumb and will be coordinated with sub transmission relocations.
14 Additional routes in the City of Detroit will be constructed and coordinated
15 with substation conversion and consolidation and the CODI program.
- 16 • 2025 will also focus on completion of critical infrastructure and resiliency
17 routes and the electronics to connect the end point substations. The program
18 will also begin to prepare for deployment of advanced wireless capabilities
19 that will reach the tens of thousands of devices that are not economical to
20 run fiber directly but will use the fiber as the high bandwidth and low
21 latency backhaul to DTEE systems. These investments will verify that the
22 communications industry marketing material contains accurate latency and
23 bandwidth and appropriate prioritization of critical traffic based on carrier
24 provided cellular build out versus an advanced wireless system supported
25 by the fiber. This evaluation will investigate methods that may be more

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- 1 economically viable options to serve the end point devices that DTEE will
2 be using to reduce customer outages and determining whether existing
3 communications can support loop schemes and advanced protection to
4 restore more of the population in a time period that does not cause disruption
5 of service beyond a normal switching transient or other short-term events.
- 6 • A small portion of the 2025 investment is to validate last mile solutions in
7 real world conditions and to document information and data received from
8 the various methods of communications, allowing an investment and
9 deployment plan for future years to be created. Testing will take into
10 account factors such as the deployment of thousands of new DER (solar,
11 storage, EVs) and bidirectional charging, all of which may need
12 coordination with demand response events during times of summer and
13 winter loading. The learning gained will also prepare DTEE to support
14 upcoming Midcontinent Independent System Operator (MISO) rules for
15 Federal Energy Regulatory Commission (FERC) Order 2222 and to fully
16 support the new clean energy law. This work in 2025 will determine
17 bandwidth, physical and cyber security requirements, and if a request for
18 proposal (RFP) should be issued for additional communication services or
19 infrastructure. It will determine if existing publicly or privately available
20 communications are sufficient to provide reliability, latency, and bandwidth
21 and to provide sufficient cyber security controls (which continue to increase
22 in complexity and depth) to support grid modernization and increasing
23 electrification.
- 24

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1 **Q49. Can you describe what the Commission found in Case No. U-21297 about Grid**
2 **Automation Telecommunications?**

3 A49. The Order summarized the conclusions of the PFD stating “[t]he ALJ noted that
4 DTE Electric expanded the scope of the program from the 500 miles of fiber and
5 230 substations proposed in Case No. U-20836 to the present proposal for 630 miles
6 and 400 substations in the test year,” then added that “[s]he [the ALJ] further found
7 that the company should be required to provide an analysis of alternatives when
8 requesting further extensions of the fiber network.” (December 1, 2023 Order in
9 Case No. U-21297, pg. 120). Earlier in my testimony I reviewed the options the
10 Company has considered for expanding the fiber network, the rationale behind the
11 Company’s decision, and the description of the Company’s planned investments in
12 this area.

13

14 Below I address the concern regarding the change in scope proposed in Case No.
15 U-21297 compared to the previous filing, Case No. U-20836.

16

17 **Q50. What led to the change in scope from 500 miles of telecommunications fiber in**
18 **Case No. U-20836 to 630 miles in Case No. U-21297?**

19 A50. The 500 miles in Case No. U-20836 only included the scope of telecommunication
20 fiber miles up through 2023 in testimony. Case No. U-21297 additionally included
21 2024 miles in testimony. The instant case also includes investment through 2025.
22 Additionally, initial estimates of routes created at the engineering level have been
23 updated for final route design, considering constructability, permitting, crossings,
24 and accessibility of the path, which results in some routes being longer and some
25 routes being shorter. Finally, the updated scope incorporated the additional fiber

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1 scope from other projects into the program. For example, the Trenton Channel
2 Power Plant decommissioning required the relocation of the legacy communication
3 infrastructure that was served from the plant. This additional scope had synergies
4 with work that was already planned in the downriver area in the fiber program,
5 resulted in a more robust solution and avoided duplicated work.

6

7 **Q51. How is DTEE controlling the investment costs for this program?**

8 A51. The Company is evaluating each route in the planning process to locate the most
9 efficient path between stations, including competitively bidding the routes to
10 multiple contractors that have demonstrated they can meet the installation
11 standards. The selected contractors can perform the make ready work as well as the
12 fiber stringing and splicing so it only requires one crew vs other approaches that
13 would have to pair a line crew with a fiber crew or a 3rd party fiber crew with a line
14 crew. The competitive bidding has been able to reduce the per mile cost on average
15 by 35% and is expanded upon in Exhibit A-19 Schedule I1.2 A similar amount of
16 savings has been seen compared to leased fiber construction routes, with the added
17 benefit of avoiding the ongoing lease cost. Contractors have also identified
18 additional savings on bulk purchasing material and scheduling work to minimize
19 mobilization costs. This has allowed the program to maintain a design target of
20 \$55K per installed mile of fiber and, on average, consistently achieve that
21 benchmark or better.

22

23 **Q52. Will the investments in the Grid Automation Telecommunications Program**
24 **continue past 2025?**

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1 A52. Yes, fiber installations are expected to continue into 2028. In 2026 and through the
2 end of the program, fiber routes will be run through a cost benefit analysis to
3 determine the appropriate future technology to be used that will support the
4 telecommunications needs of all other DTEE investments and programs. This is
5 also being done to align construction of the fiber with sub transmission relocation
6 to prevent installation of fiber in locations where the lines are planned to be moved,
7 and to complete the installation of electronics and taps into substations. Future
8 investments will also include the integration of an advanced wireless system to
9 connect to additional device locations and assets inside the service territory. This
10 proposed second phase of the grid telecommunications installation top address the
11 last mile devices is projected to run through the end of the decade.

12

13 C. **Conservation Voltage Reduction and Volt-Var Optimization (CVR/VVO)**

14 **Q53. What is Conservation Voltage Reduction and Volt-Var Optimization?**

15 A53. Volt Var Optimization (VVO) manages system-wide reactive power flow to
16 achieve one or more specific operating objectives. The objectives can include
17 reducing losses, managing circuit level voltage, optimizing operating parameters
18 and/or optimizing power factors, etc.

19

20 Conservation Voltage Reduction (CVR), as one of the VVO options, is designed to
21 maintain customer voltage down to the circuit level in the lower portion of the
22 allowable voltage ranges, thus reducing system losses, peak demand and energy
23 consumption.

24

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1 CVR is achieved by utilizing various electrical equipment including transformer
2 load tap changers (LTC), overhead line regulators, and capacitor banks. In addition,
3 supervisory control and data acquisition (SCADA) monitoring devices and line
4 sensors are used to ensure customer voltage levels are maintained in allowable
5 voltage ranges; advanced telecommunication and optimization tools can also be
6 used to achieve optimal savings in the system.

7

8 **Q54. What are the benefits and drivers of the CVR/VVO Program investments?**

9 A54. CVR/VVO provides both a benefit to the distribution system as well as a
10 generation alternative through reduced demand and energy consumption. Initial
11 pilots conducted in 2020 through 2022 on six circuits using local control achieved
12 peak reductions of 0.9% to 1.4% and energy savings of 0.7% to 1.0% and would be
13 expected to raise to industry standard level 1.5% to 3% with the use of ADMS based
14 CVR/VVO control. The CVR/VVO program is targeting a total peak demand
15 reduction of up to 38 MW by 2030. In addition, CVR/VVO is, and will continue
16 to be, a part of DTE Electric's integrated resource portfolio and are part of a utility
17 system framework within the comprehensive context of an integrated resource
18 planning process.

19

20 **Q55. What work related to CVR/VVO has been completed to date?**

21 A55. DTE Electric successfully enabled CVR/VVO technology on six pilot circuits in
22 two substations on the distribution system in December 2020. CVR/VVO was
23 enabled and measured throughout 2021 and produced demand and energy savings
24 that were in line with the projections in DTE Electric's 2019 IRP filing (Case No.
25 U-20471). CVR/VVO was enabled throughout 2022 and there have been no

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1 additional investments related to the pilot. The program was paused in 2022 and
2 2023 to align the program with advancements in ADMS that would allow for the
3 use of ADMS CVR/VVO modules for control in place of the local electronic
4 control used in the pilot. Although the program was paused, in 2023, engineering,
5 design and the replacement of failed capacitors and capacitor controls with units
6 that support CVR/VVO was completed.

7

8 **Q56. What is the scope of work for the CVR/VVO Program for 2024 and 2025?**

9 A56. In 2024, 22 circuits will be upgraded for \$2.5 million. Circuit upgrades include the
10 replacement of 36 capacitors and controls, four regulator control replacements, and
11 the installation of 20 voltage monitoring locations. This work will allow for ADMS
12 monitoring and control of voltage through CVR/VVO modules.

13

14 In 2025, 22 circuits are expected to be upgraded for \$2.5 million. Circuit upgrades
15 include the replacement of 40 capacitors and controls, two regulator control
16 replacements, and the installation of 22 voltage monitoring locations. This work
17 will allow for ADMS monitoring and control of voltage through CVR/VVO
18 modules. In addition, the Company's scope of work includes a targeted capacitor
19 control replacement program to address end of life capacitor controls that rely on
20 time-based radio control. The existing radio controls have been determined to be
21 obsolete by the manufacture and spare components for the radio transmitter are at
22 risk of not being available. The capacitor control replacement program portion of
23 the 2025 scope includes \$5.6 million to replace 737 capacitor controls, bringing the
24 total cost for 2025 to \$8.1 million.

25

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1 **Q57. How is the Capacitor Control Replacement Program related to CVR/VVO and**
2 **what are the benefits?**

3 A57. The Capacitor Replacement Program is a one-time investment to replace end of life
4 and failed capacitor controls across the distribution system that could be utilized by
5 CVR/VVO. The installations will be replacing the obsolete capacitor controls with
6 the current standard control and installing sensing equipment that will allow for
7 monitoring and remote control of the capacitor through SCADA and the ADMS.
8 Replacing the existing capacitor controls with new SCADA enabled controls will
9 allow for those units to be integration into CVR/VVO program. The capacitors
10 replaced will be able to be controlled by the ADMS VVO module and provide real
11 time optimization of the circuit voltage and reactive power. This will provide some
12 efficiency benefit to the circuit related to improved power factor, but the circuits
13 they are on will not have the voltage reduced to gain extra energy efficiency savings
14 from CVR. Customers will also see the benefits of reduced losses from improved
15 power factor and voltage management on the circuit.

16

17 **D. Non-Wire Alternatives (NWA) Pilots**

18 **Q58. What are Non-Wire Alternatives?**

19 A58. Non-Wire Alternatives (NWA), as initially defined by the Commission on page 11
20 of the August 20, 2020 Order in Case No. U-20147, are, “An electricity grid
21 investment or project that uses distribution solutions such as distributed energy
22 resources (DER), energy waste reduction (EWR), demand response (DR), and grid
23 software and controls, to defer or replace the need for distribution system
24 upgrades.”

25

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1 **Q59. Why is the Company evaluating NWA?**

2 A59. The August 20, 2020 Order in Case No. U-20147 (“August 2020 Order”) stated on
3 pages 43 and 44 that “the Commission expects to be presented with ‘a robust suite
4 of NWAs that may be evaluated for prudence as possible programs.’” Consistent
5 with that Order, the Company developed a set of NWA pilots utilizing different
6 technologies and addressing different grid concerns for inclusion in the 2021 DGP.
7 Since 2018, DTE Electric has been implementing those NWA pilots using
8 alternative technologies to address circuits or substations with loading concerns to
9 help delay or offset traditional system upgrades. The Company plans to continue to
10 implement the remaining pilots, as well as analyze the results of the completed
11 pilots. This is also consistent with the industry’s evaluation of the opportunities that
12 NWA’s present.

13

14 **Q60. Did the Company present its NWA projects in its previous rate case?**

15 A60. Yes, the Company proposed its NWA projects in Case No. U-21297. In its
16 December 1, 2023 Order in that case the Commission approved the following
17 projects: O’Shea (pg. 127); Omega (pg. 128); Mobile Battery Trailer (pg. 128);
18 Fisher (pg. 129); Port Austin (pg. 128); and Veridian (pg. 130).

19

20 **Q61. What is the Company’s objective for NWA?**

21 A61. The Company’s objective is to incorporate NWA solutions into the distribution
22 planning process to be considered along with traditional options to best meet the
23 customer needs as described in the Company’s 2023 DGP, Exhibit A23, Schedule
24 M8, on pages 95 and 96. The pilots currently being pursued are building blocks that
25 will form a foundation for future NWA projects. As capabilities are confirmed,

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1 multiple NWA technologies can be combined to further advance the Company's
2 utilization of NWA.

3

4 **Q62. What are the potential customer benefits of NWAs?**

5 A62. NWA projects have the potential to become economic alternatives compared to
6 traditional infrastructure upgrades. The pilots are expected to validate customer
7 and economic benefits to help further refine the analysis of NWAs as an alternative
8 to traditional solutions. While individual participating customers benefit from
9 investment in some of the technologies used in targeted NWA solutions, such as
10 lower energy bills due to EWR, customers overall may benefit from the deferred or
11 displaced investment in infrastructure.

12

13 **Q63. Can you please describe the NWA investments included in the instant case?**

14 A63. The Company is currently engaged with a suite of nine NWA pilots. Some of the
15 pilots are still under evaluation while others are in progress or have been completed.
16 The NWA pilots are listed in Table 2 along with the use cases and technology the
17 pilots are intended to test. The Hancock Pilot was completed and described in
18 MPSC Case No. U-20836, and the remaining planned pilots are fully described in
19 Exhibit A-12, Schedule B5.4.1 to Exhibit A-12, Schedule B.5.4.7, Exhibit A-12,
20 Schedule B.5.4.9 and Exhibit A-23, Schedule M7.

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Table 2 NWA Pilots Use Cases, Technologies, and Objectives

Use Case	Pilot	Technology							Objective
		EWR	DR	Storage	Solar	BTM DER	EV Charging	Microgrid	
Voltage Mitigation	1. O'Shea			✓					· Test effectiveness of storage to address voltage instability due to intermittent solar
Portable Battery	2. Mobile Battery Trailer			✓					· Test use of energy storage in place of traditional portable generators
Sub-transmission Loading	3. Omega			✓					· Deploy storage to address subtransmission loading · Install battery that can be re-located
Substation Loading	4. Hancock (Completed)	✓							· Initial pilot to test geo-targeted EWR and develop DER Estimating tool
	5. Fisher	✓	✓						· Test geo-targeted EWR/DR costs · Measure implementation timing
	6. Port Austin			✓	✓			✓	· Test solar and storage to address substation capacity · Test redeployment of stationary battery from Omega
Customer Load and DER Control	7. Veridian		✓	✓	✓	✓	✓	✓	· Develop secure and effective methods to interface and control behind the meter (BTM) DER in conjunction with utility scale DER
EV Charging	8. EV Demonstration at ACM						✓		· Develop control algorithms and conduct testing on an extreme fast charger and its interfaces as well as develop cyber secure smart charge management capabilities for Department of Energy
Reliability	9. Adaptive Networked Microgrids			✓	✓	✓		✓	· Develop and test the use of adaptive networked microgrids to improve customers' reliability and increase the benefits of NWA deployments

2
34 **Q64. Can you elaborate on the technologies included in Table 2?**

5 A64. Yes. EWR refers to replacing less efficient equipment with more efficient
6 equipment, reducing overall electrical demand. DR refers to a shift or reduction in
7 electricity usage by a utility customer to help manage demand on the electrical grid
8 during periods of peak demand. Behind-the-Meter (BTM) refers to coordinating
9 the participation of customer equipment to reduce overall demand or provide other
10 system benefits. Electric Vehicle (EV) charging refers to coordinating the charging
11 or discharging of EV equipment to provide electrical system benefits, avoid
12 electrical system issues or address loading concerns.

13

14 **Q65. Can you provide more detail on the Company's NWA pilot projects?**

Line
No.

1 A65. Yes. Each pilot is described in detail in the following sections and Exhibit A-12,
2 Schedule B5.4.1 to Exhibit A-12, Schedule B.5.4.7, Exhibit A-12, Schedule
3 B.5.4.9, and Exhibit A-23, Schedule M7 provide additional details.

4
5 **O'Shea**

6 **Q66. Can you briefly describe the O'Shea Pilot?**

7 A66. Yes. A 1 MW by 1 MWh Battery Energy Storage System (BESS) is being
8 interconnected at the O'Shea Solar Park. O'Shea is a DTEE owned 2MW solar
9 array installed on a circuit from the Chicago substation on the west side of Detroit
10 to address power quality concerns related to the intermittent nature of the installed
11 solar generation. The BESS is expected to address power quality for those
12 customers.

13

14 **Q67. What progress has been made for the O'Shea Pilot?**

15 A67. DTEE has completed the below grade work at the site, poured concrete support
16 pads, and installed the battery housing. The controls have been procured and are
17 undergoing testing, and the site is ready for battery installation. The project has
18 allowed the Company to create standard designs and to develop operation
19 procedures, safety plans, and maintenance instructions. These learnings and the
20 opportunity to test compliance to standards have resulted in the creation of safety
21 policies for the installation and usage of battery systems that support not only this
22 project but other storage projects in the future as well. The O'Shea Pilot has further
23 allowed for the development of processes and practices for interconnecting battery
24 systems at renewable sites.

25

Line
No.

1 **Q68. Does the O'Shea Pilot require any additional work?**

2 A68. The tasks remaining are installing and commissioning the battery modules into the
3 battery housing and then validating the control systems, communication
4 infrastructure, new processes, standard designs, and other aspects of the pilot. The
5 capability for the battery system to demonstrate participation in the wholesale
6 market will be tested in consideration of FERC Order 841 to vet processes controls
7 and communications that can be replicated at future battery sites.

8

9 **Mobile Battery Trailer**

10 **Q69. Can you briefly describe the Mobile Battery Trailer Pilot Project including the**
11 **customer benefits?**

12 A69. Adding to the Company's mobile resources supporting geo-targeted major event
13 restoration, DTE Electric has developed a mobile battery system that is capable of
14 providing temporary power to a circuit and also supporting local system voltage.
15 The mobile system consists of three separate trailers. Two trailers contain batteries
16 (DC battery trailers), and the remaining trailer contains an inverter and system
17 interconnection equipment (medium voltage trailer). The mobile battery systems
18 have zero emissions and can support customer restorations in several ways
19 including siting in place of traditional portable generators, supporting system
20 requirements during shutdowns or maintenance, or being deployed at substations
21 or on circuits to reduce peak load as part of a broader NWA project. The systems
22 are designed to operate stand alone or in conjunction with other mobile resources.

23

24 **Q70. What progress has been made in 2023?**

Line
No.

1 A70. The medium voltage and DC battery trailers have been delivered and connected at
2 the DTEE Westland training center, where the solar and storage testbed is located,
3 to allow for detailed checkouts of controls and onboard systems. Battery system
4 communications, control functions and alarm screens were implemented on the
5 trailers and run through testing. Initial documentation, procedural walkdowns,
6 safety reviews, and testing of the house service and alarming systems were
7 completed in 2023. Several modifications were identified and implemented to
8 improve the deployment time and improve safety when operating the trailers.

9

10 **Q71. What work is remaining for the Mobile Battery Trailer Pilot?**

11 A71. Medium voltage testing will occur in early 2024 to validate the battery system
12 control modes and communications with the System Control Center. These first
13 tests will include validating functionality for the battery system including operator-
14 controlled charging and discharging, peak shaving, volt var control, and solar
15 smoothing as well as the onboard monitoring and safety systems. Procedures for
16 disconnecting, moving, and reconnecting the battery systems will be field tested to
17 allow for finalization of job units and work procedures. The systems will also be
18 tested to work with other mobile resources and DER prior to deployment for
19 support of the grid. During the testing, enhancements to functionality and control
20 modes will be integrated into the Battery Trailer System(s) to increase the number
21 of use cases the systems can support, and these enhancements will be propagated
22 to the other Battery Trailer Systems.

23

24 **Omega**

25 **Q72. Can you briefly describe the Omega Pilot Project?**

Line
No.

1 A72. Yes. The Omega Pilot Project is located in the high growth area of Harrison
2 Township. Two subtransmission lines feed Omega substation and both have been
3 impeding further growth. In the near term, the placement of mobile storage
4 equipment (the same type of equipment described in the Mobile Battery Trailer
5 section) at the Omega substation will be used to reduce peak loading on the
6 transformers and subtransmission lines during contingencies, validating the ability
7 of the mobile battery for peak load reduction and load shift use cases. The mobile
8 batteries will be moved to other project locations, for example, Port Austin, once
9 this capability demonstrated.

10

11 **Q73. What work has been completed for the Omega Pilot?**

12 A73. Engineering, design, and construction were completed for the site. Standards have
13 also been developed to improve the efficiency of future applications of storage for
14 the same purposes. The Company learned technical specifications and requirements
15 to integrate battery storage equipment with the electrical system in a safe and
16 reliable manner. The Battery Trailer Systems were delivered on site in Q4 2023
17 and connected to house service power.

18

19 **Q74. What work is remaining for the Omega Pilot?**

20 A74. Checkout and commissioning of the mobile battery systems is expected to be
21 completed by end of Q2 2024. Upon completion, the controls and protection can
22 be fully tested, and the medium voltage trailers can be connected to the distribution
23 system. Additionally, the commissioning process and operational procedures in the
24 control room and field for coordinating multiple battery systems at the same site
25 will be established.

Line
No.

1 **Fisher**

2 **Q75. Can you briefly describe the Fisher Pilot?**

3 A75. Yes. Fisher substation is located in Gibraltar and is over its firm capacity rating. In
4 addition, two circuits served by Fisher are expected to be over the design standard.
5 This poses significant risk of outages and inability to serve customers. The
6 Company originally considered adding capacity at the substation by upgrading
7 from a Class “F” substation to a Class “A”³ substation, replacing existing substation
8 transformers with larger transformers, installing a nine position Power Distribution
9 Center (PDC⁴), and adding two new circuits to split the load. The Company then
10 considered NWAs. The NWA scope includes targeted deployment of DR and EWR
11 to relieve a portion of the load concerns. The remaining load concerns at Fisher will
12 be addressed with the installation of an STDF (Subtransmission Distribution
13 Facility⁵) in a 120kV corridor. This will allow one of the existing circuits to be
14 split. The combination of energy waste reduction, demand response, and the STDF
15 will address the loading concerns and return these circuits to their design capacity
16 ratings.

17

18 **Q76. What has been the progress and results of the EWR work at Fisher?**

19 A76. The Company has been working on EWR in collaboration with the MPSC Staff and
20 the Natural Resources Defense Council. The team continues to design and plan a
21 cost-effective mix of pilot programs to deliver an estimated 300 peak-kW reduction

³ A class F is a small substation consists of two transformers and three breakers, while a Class A substation is more automated and has two or more transformers with each transformer having its own breaker

⁴ A PDC is a power feed to a bus bar that supplies the individual circuits fed from a substation. It is similar in function to a breaker panel in a home at a much larger scale.

⁵ A facility that consists of a set of equipment which creates a single circuit from a subtransmission connection.

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1 over the span of three years in the field. The pilots include geo-targeted bonus
2 incentives to deliver off peak-load relief for premises connected to Fisher circuits.
3 EWR progress for year-end 2023 is at a 139 peak-kW reduction.

4

5 **Q77. What EWR work is still to be completed for the Fisher project and what is the**
6 **expected timeline for that work?**

7 A77. The field pilot programs will run for three years and are expected to be completed
8 in 2025.

9

10 **Q78. Are the EWR costs included in Exhibit A-12, Schedule B5.4?**

11 A78. No. Energy Waste Reduction pilot costs are included as part of the Company's
12 EWR Plan in Case No. U-20876, Exhibit A-11 and Exhibit A-14.

13

14 **Q79. What has been the progress and results of the DR work at Fisher?**

15 A79. As of Q4 2023, there is a cumulative total of 183 customers at the Fisher substation
16 enrolled in the Smart Savers program; 57 new customer enrollments can be
17 connected back to 2023 marketing initiatives. Based on a third-party forecasted
18 analysis, these customers could each provide an average of 0.62 kW in load shed
19 per event for a total of approximately 113 kW available in demand savings. As of
20 Q4 2023, there are also a total of 298 CoolCurrents customers online and
21 dispatchable at the Fisher substation. Based on the third-party forecasted analysis,
22 these customers could each provide an average of 0.53 kW in load shed per event
23 for a total of approximately 158 kW available in demand savings. In addition to the
24 298 online customers, the DR team has identified 201 CoolCurrents customers at
25 the Fisher substation who are currently offline because they do not have a proper

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1 24-volt power source connection. The Company has identified a solution for this
2 and will be implementing it in 2024.

3

4 **Q80. What DR work remains to be completed for the Fisher Pilot and what is the**
5 **expected timeline for that work?**

6 A80. The Fisher Pilot was launched in 2022 and is forecasted to run for three years until
7 2025. The DR team will continue to deploy enhanced marketing efforts for the
8 Smart Savers program to drive incremental enrollment. The DR team will also
9 continue efforts to restore offline CoolCurrents customers.

10

11 **Q81. What has been the progress and next steps for the STDF?**

12 A81. Preliminary engineering and design are completed. Reconductoring is expected to
13 start in early 2024 and final construction is expected to be completed in 2024. The
14 design for the STDF installation is forecasted to start in 2024, and the STDF will
15 be installed and operational in 2024.

16

17 **Port Austin**

18 **Q82. Can you briefly describe the Port Austin NWA Pilot?**

19 A82. Yes. The Port Austin substation, located at the tip of the thumb, is over its firm
20 rating, one circuit is over its day-to-day rating, and there are short periods of low
21 voltage at the end of the circuits during periods of peak demand. The substation
22 voltage is 4.8 kV, and the traditional method for addressing these concerns would
23 be to convert the area to the higher 13.2 kV. However, significant load growth is
24 not forecasted in this area, which makes this a lower priority for conversion
25 compared to other areas. Additionally, this area is vulnerable to severe weather and

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1 experienced two tornadoes in recent years. With these considerations, the
2 Company is piloting the application of solar generation combined with energy
3 storage to address these concerns. Deployment of this equipment and using it to
4 form a microgrid will benefit and supply power to a portion of the customers on the
5 circuits if an event creates a fault that interrupts service from the substation.

6

7 **Q83. What progress was made from 2022 through 2023?**

8 A83. Engineering was completed for the Port Austin project in 2022 and detailed design
9 was completed in early 2023. The purchase of the property was completed in 2023.
10 Project construction permits were secured from Huron County in the fall of 2023.
11 The solar equipment was purchased in 2022 and was delivered to DTEE in 2023.
12 Site preparation and construction started in the fall of 2023.

13

14 **Q84. What work remains for the Port Austin Pilot?**

15 A84. Site construction needs to be completed and a mobile battery system will be
16 delivered to the site. The control systems, communication infrastructure, new
17 processes, standard designs, and other aspects of the pilot will be fully verified once
18 the batteries and solar are installed, and the capability for the battery system to
19 demonstrate participation in the wholesale market will be tested in consideration of
20 FERC Order 841.

21

22 **Veridian**

23 **Q85. Can you briefly describe the Veridian NWA Pilot?**

24 A85. Veridian is a planned residential subdivision development in Ann Arbor made up
25 of mixed use and community buildings and approximately 150 residential units that

Line
No.

1 are a combination of detached single-family homes, townhomes and multi-unit
2 dwellings. The area is served by the 4.8 kV Regent substation. While substation
3 loading is not the primary concern, the overall load of the development is expected
4 to approach 1.5 MVA, and none of the existing circuits have capacity to
5 accommodate this level of load growth. However, the developer is planning to
6 deploy customer owned solar and storage. By carefully coordinating the usage of
7 the customer deployed DER with utility controls, system upgrades can be
8 minimized yet still deliver the safe and reliable power required for this
9 development. There are three aspects of the project: installing a URD loop,
10 completing system upgrades, and developing a microgrid.

11

12 **Q86. What work remains to be completed for the Veridian Pilot?**

13 A86. Design is underway for the underground residential distribution (URD) and
14 reconductoring portions of the Veridian project. The URD loop construction is
15 currently scheduled to align with the developer's project plan, extending through
16 early 2024. The system upgrade portion of the project began construction in 2023
17 and will be completed in 2024. The microgrid portion of this pilot is currently in
18 detailed engineering study, and controls design, procurement, and construction will
19 begin in 2024 and continue into 2025, aligning with occupancy of the development
20 and the solar/storage DER components going on-line.

21

22 **EV Charging Demonstration at ACM**

23 **Q87. Can you briefly describe the NWA: EV Charging Demonstration at ACM**
24 **investment?**

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No.

1 A87. This project includes investments in several different EV charging technologies and
2 projects to learn how the various technologies will impact the grid. This includes
3 the Department Of Energy (DOE) DE-EE0008361 Xtreme Fast Charging demo at
4 ACM, the DOE VTO FOA-2197 EVs at RISC program, and the Electreon in-road
5 charging pilot in Corktown sponsored by MDOT. The project scope also includes
6 engineering support for transportation electrification including work with
7 automotive OEMs and suppliers, engineering support and testing for managed
8 charging pilots, engineering support for electric school buses, engineering support
9 for Vehicle to Home (V2H) charging pilots, engineering support for Vehicle to Grid
10 pilots (V2G), development of V2H and V2G interconnection requirements,
11 charging interoperability testing and the distribution engineering support, testing
12 and validation for many of the pilots initiated in the Emerging Technology Fund,
13 which is described in Witness Pina Bennett's testimony at page 61.

14

15 **Q88. Has the Commission addressed this project in a previous order?**

16 A88. In its December 1, 2023 Order in Case No. U-21297 the Commission stated:

17

18 The Commission notes that in the November 18 order, pp. 159-161, the
19 Commission approved only 10% of the requested funding for this pilot.
20 Based on the record in the instant case, the Commission is not
21 persuaded to approve additional funding at this time. The Commission
22 agrees with the Attorney General's assessment of the technology as
23 currently so experimental as to be premature for funding by ratepayers.
24 See, 6 Tr 3680-3681. Further, it is unclear what benefits—if any—
25 would be available to DTE Electric's customers other than ACM,
26 making it difficult to justify the reasonableness and prudence of having
27 all customers pay for this pilot. (MPSC, p. 131)

28

29 **Q89. Is the Company providing testimony to address the Commission's stated**
30 **concerns?**

Line
No.

1 A89. Yes, additional support for cost recovery of this investment is provided to address
2 the Commission's stated concerns. Furthermore, the historical project name is
3 being kept for consistency even though the investments in EV technology programs
4 addresses a broader scope of EV projects than the ACM Xtreme Fast Charging
5 Project, and the ACM project component was completed in 2022.

6

7 **Q90. Why were other EV project investments grouped with the NWA: EV Charging**
8 **Demonstration Pilot at ACM?**

9 A90. Originally, when the project was created it supported multiple EV technology
10 projects that were under consideration. The project that was furthest in
11 development, (dating back to 2018) was the DE-EE0008361 Xtreme fast charging
12 demo at ACM. The pilot's name was applied to the budget category even though it
13 contained other EV projects, because at the time those other projects were still in
14 initial stages and did not have any significant investment. The project name has
15 been retained through subsequent cases for consistency even though it doesn't fully
16 describe all the investments in the category. Table 3 provides a breakdown of the
17 split between the ACM spend and that from other EV technology projects.

18 **Table 3 Cost breakdown of ACM compared to total program**

	2022	2023	2024	2025
ACM	\$ 697,000	\$ -	\$ -	\$ -
EV Programs	\$ 595,000	\$ 1,292,000	\$ 920,000	\$ 2,500,000
Program Total	\$ 1,292,000	\$ 1,292,000	\$ 920,000	\$ 2,500,000

19

20 **Q91. What is included in Historical funding year for NWA: EV Charging**
21 **Demonstration at ACM Pilot investment?**

Line
No.

1 A91. At the ACM site, work included site preparation, below grade cable and conduit
2 installation, foundations for equipment, installation of a medium voltage switch for
3 isolation and operating, installation of relaying and power quality meter and
4 communications and control hardware to measure and record data from charging
5 events. The Xtreme fast charger successfully completed initial charging
6 demonstrations in fall of 2022 and culminated in the demonstration to the
7 Department of Energy on Oct 13, 2022⁶.

8
9 For the other EV programs in this category, the work was primarily for the DOE
10 VTO FOA-2197 EVs at RISC program⁷ and focused on validating the data model
11 and cyber security implementations necessary to provide managed charging in a
12 multi stake holder environment where charging was dynamically controlled by grid
13 conditions. This included an initial proof of concept demonstration to the
14 Department of Energy of the system's ability to control vehicle charging locally
15 and remotely based on real time grid conditions while implementing the required
16 cybersecurity practices to maintain isolation of the utility control network.
17 Additional work was performed on EV charging station protocol interoperability
18 and compatibility for managed charging and demand response and initial
19 investigations into the Electreon electric road technology and Vehicle to Grid
20 functionality and standards.

21

⁶ [High-Efficiency, Medium-Voltage-Input, Solid-State-Transformer-Based 400-kW/1000V/400A Xtreme Fast Charger for Electric Vehicles \(Technical Report\) | OSTI.GOV available at https://www.osti.gov/biblio/1987553](https://www.osti.gov/biblio/1987553)

⁷ EVs-at-RISC: A Secure and Resilient Interoperable Smart Charge Management Control System Architecture for Electric Vehicles At-Scale : [elt265 \(energy.gov\)](https://www.energy.gov/sites/default/files/2021-07/elt265_woodbury_2021_o_5-14_500pm_KF_ML.pdf) available at https://www.energy.gov/sites/default/files/2021-07/elt265_woodbury_2021_o_5-14_500pm_KF_ML.pdf

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1 **Q92. What investments are included in the test and forecast year funding?**

2 A92. A major portion of the investment during the test years is the technical
3 demonstration of the DOE program for DE-FOA-0002197, EVS-at-RISC (Electric
4 Vehicle Secure - Resilient Interoperable Smart Charging) This includes the initial
5 and widescale demonstration of the system controlling multiple publicly accessible
6 chargers in and around the Michigan central campus in Corktown. This
7 demonstration will help the Company develop cyber-secure monitoring and control
8 capabilities with smart charge controls to ensure reliable and secure interfaces to
9 customer systems. The project will further enhance knowledge of the grid impact
10 of these new management technologies. The electric Marketing organization has
11 initiated Smart charge management projects that will be tested in multiple phases
12 through 2023 and 2024 at the DTEE DER lab. Testing of vehicle protocol and
13 interoperability will continue; especially as new commercially available systems
14 integrate more directly with solar and storage and feature more complex controls
15 and the ability to operate offline. Investments in the development of V2G and
16 interconnections documentation will be completed in 2024 year. Engineering will
17 also be done on the inductive road charging project to better understand the power
18 quality impacts of wireless charging. Engineering support for Electric Vehicle
19 Emerging Technology Fund (ETF) is primarily around providing feedback to the
20 individual projects design. Work also includes supporting the implementation of
21 testing of the solution and validating the technical performance of the projects.

22

23 **Q93. Is there investment in the ACM portion of the project in the bridge years 2023**
24 **or 2024 or in the projected test year of 2025?**

Line
No.

1 A93. No, other than project close out and accounting, the specific work at ACM was
2 completed in 2022 and the investments in this category are at sites other than ACM.
3 DTEE continues to monitor the charger and solid-state transformer to gather
4 additional data on charging events.

5

6 **Q94. Can you describe the specific work for the NWA: EV Charging Demonstration**
7 **at ACM?**

8 A94. Yes, in addition to the information provided in Exhibit A-12, Schedule B5.4.7, the
9 EV Charging Demo at ACM Project included DTE Electric supporting the
10 implementation of the Delta Power Electronics DC Xtreme 400KW fast charger
11 and solid state transformer installation as part of the DOE project DE-
12 EE0008361/DE-FOA-0001808. The purpose of which was to gain understanding
13 of the impacts of high-powered EV charging on power quality and operations. The
14 pilot installed a power quality meter, utility gateway, and communications portal to
15 (a) enable charge management, (b) develop control algorithms and conduct testing
16 on a Delta Extreme fast charger and its interfaces, (c) develop cyber security
17 interfaces and control, (d) install additional sensing capabilities, (e) monitor
18 performance on the charging network, and (f) develop monitoring and control
19 algorithms for in-road inductive charging at the ACM site. The DE-EE0008361
20 project began in 2018 with Delta being the prime recipient of funding to develop
21 the extreme fast charger and associated solid state transformer, where most of the
22 research and development work occurred at the Delta facility in Livonia. The
23 project team members also included DTEE, General Motors (GM), Next Energy,
24 Virginia Tech, the City of Detroit, and the Michigan Energy Office. This teaming
25 is typical of DOE grant projects where a private technology partner teams with a

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1 university, national labs, and a utility partner to demonstrate a technology of
2 interest to the Department of Energy. The project stated goals to the DOE were:

3 *AREA OF INTEREST (AOI) 1: Extreme Fast Charging (XFC) Systems for Electric*
4 *Vehicles:*

- 5 • *To design and test a high-efficiency, medium-voltage-input, solid-state-*
6 *transformer-based 400-kW Extreme Fast Charger (XFC) for electric*
7 *vehicles, achieving better than 96.5 percent efficiency.*
- 8 • *To demonstrate extreme fast charging with a retrofitted General Motors’*
9 *light-duty battery electric vehicle at 3C or higher charging rate for at least*
10 *50 percent increase of SOC.*
- 11 • *To achieve a 180-mile charge within 10 minutes.*

12
13 Stated benefits of the technology development were (a) a reduced amount of low
14 voltage electrical equipment, (b) reduced charging losses, (c) the allowance of more
15 direct integration of DER and storage into the system, (d) reduced space required
16 for the unit, and (e) reduced labor to install high powered charging.

17 The initial Delta fast charger prototype was available by the end of 2020 and was
18 tested electrically at the Next Energy microgrid. The second phase was field
19 demonstration and installation which took place in late 2022 with a demonstration
20 for the Department of Energy showing 400KW charging on commercially available
21 vehicles and the use of a solid-state transformer.

22 The American Center for Mobility (ACM) demonstration was a collaboration
23 between Delta, DTE Energy, and ACM. The ACM site draws directly from medium
24 voltage 13.8 kV, which was already available at the station. ACM also provides a
25 step towards “real-world” usage in a semi-controlled environment, as many ACM

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1 customers are running tests with electric vehicles where a fast charge will help them
2 get back to testing quickly. The site constructed under the project closely mimics
3 the process for fielding a medium voltage EV charger at other sites.

4

5 **Q95. Is the charging technology demonstrated at ACM experimental and**
6 **premature?**

7 A95. No, the specific charger installed at ACM contained additional testing
8 instrumentation and required more access for configuration than a final product.
9 The ACM site charger, while not available commercially, has resulted in a
10 commercial product that Delta is currently working to bring to market. The
11 demonstration for the Department of Energy showed charging of 2023 model year
12 vehicles, including a GM EV Hummer at full power of 400 KW and operating at
13 the maximum of 800V, double the standard charging voltage in older EVs. This
14 showed that the system could readily perform DC fast charging of a Ford F-150
15 Lightning, Chevy Bolt, and Cadillac Lyriq at their maximum charge rate as well.
16 All these vehicles were standard production and unmodified. This technology
17 demonstration is fundamental to encouraging rapid electrification and improving
18 the charging experience for EV owners by reducing the charging time for a full
19 charge from multiple hours to just minutes. This project demonstration identified
20 best practices that can be applied to any similar high powered future charging
21 projects that would result in reduced design and construction costs and allow for
22 the early identification of potential roadblocks to installation. The scope of
23 evaluation with the Department of Energy is to demonstrate technical feasibility
24 and meet demonstration milestones. The Department of Energy Vehicle

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1 Technology Office has clear criteria to facilitate the commercialization of
2 technologies demonstrated.

3

4 **Q96. Does the ACM project show a successful approach to leveraging other funding**
5 **sources to innovate and support electrification?**

6 A96. Yes. Delta, the primary recipient of the grant, funded development of the solid-state
7 transformer and extreme fast charging system and provided the equipment to the
8 project. The Company fulfilled the role of the host utility to provide engineering
9 input into the project to reach a successful integration of the grid connection and
10 engineering and operating support. ACM acted as the site host for the
11 demonstration primarily because initial testing required vehicles that were heavily
12 modified to accept the high-powered charging and these vehicles were not certified
13 to drive on the open road thus requiring a test track location. Without the initial
14 testing on the closed track, there was no way to rapidly discharge the vehicle
15 batteries to perform cycle testing on the system to validate that the power
16 management and thermal management of both the vehicle and the charger was
17 performing as expected. For the final demonstrations, the test vehicles were
18 replaced with production models as GM had integrated the technology into their
19 core drivetrain platform by that time.

20

21 **Q97. What benefits did the ACM Pilot have that can be applied beyond the ACM**
22 **site?**

23 A97. By participating in Department of Energy projects that include equipment
24 manufacturers and research institutions, DTEE is able to obtain valuable
25 information on technologies such as extreme fast charging as well as on solid-state

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1 transformer technology performance. DTEE also supported Delta in developing a
2 product that would allow high power charging to be deployed more cost effectively
3 in the future by eliminating equipment and construction costs for unnecessary
4 secondary voltage equipment and transformation. Additionally, DTEE evaluated
5 the method needed for grid connection and operation at high powered charging sites
6 that will not have on site trained electrical staff like an industrial facility might
7 have. The demonstration also provided experience with solid state transformer
8 technology where the EV charger direct current is directly coupled to the medium
9 voltage primary system, allowing for higher charging rates and significant
10 efficiency gains by eliminating traditional transformation and secondary voltage
11 wiring.

12

13 **Q98. What benefits do the other EV charging investments beyond the ACM Pilot**
14 **have for customers?**

15 A98. As EV's become more prevalent in the Company's service territory, the learnings
16 from these projects will support a more efficient incorporation into the grid, laying
17 the groundwork for EV's to be a grid-benefitting resource. There are three major
18 benefits for the additional investments.

- 19 • Create a consistent and clear set of standards and requirements for the
20 connection and operation of Vehicle to Home (V2H) and Vehicle to Grid
21 (V2G) technologies and to use these as the baseline for necessary changes
22 in processes and organizations that directly interface with the customer that
23 is requesting those capabilities to streamline that experience.

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- 1 • Define and implement the appropriate communication, cybersecurity, and
- 2 control architectures for managed charging to allow for greater adoption of
- 3 EV charging and minimizing the impact of grid constraints.
- 4 • Increase insight into the benefits of managed charging and the impact of EV
- 5 charging on system loading and power quality, especially at high
- 6 concentrations of charging to optimize circuit design and develop consistent
- 7 methods for modelling the variability of managed charging and EV
- 8 charging, this information will translate to projects that are better at
- 9 integrating electrification.

10

11 **Adaptive Networked Microgrids**

12 **Q99. Are there any additional pilots proposed based on the work at O’Shea and**
13 **Port Austin?**

14 A99. Yes. DTE Electric has been selected by the DOE for Infrastructure Investment and
15 Jobs Act (IIJA) funding to expand on the Company’s NWA work. Negotiations to
16 finalize the project award expected to continue until sometime in the second quarter
17 of 2024. DTE Electric will use this funding to grow the deployments at O’Shea
18 Solar Park and Port Austin substation and to incorporate Adaptive Networked
19 Microgrids (ANMs) to further increase the customer benefits from the deployed
20 assets.

21

22 **Q100. Why were these sites selected?**

23 A100. DTE Electric is dedicated to the deployment of renewable NWA projects, and the
24 ANMs will be an extension of that work. Both sites have assets already deployed
25 that can be used in the networked microgrids. The NWA deployments for each were

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1 described earlier in my testimony, and by selecting these sites, the overall cost will
2 be lower. Furthermore, Chicago substation / O'Shea is in an urban area with a high
3 energy justice score, and Port Austin substation is in a rural area with longer
4 circuits. Between these two locations, the ANM concept can be fully developed and
5 tested for the benefits it provides customers in a range of settings. Additionally,
6 both areas are served by 4.8 kV ungrounded delta circuits. When the reclosers are
7 placed near the start of the circuit to detect and isolate grounds, the networked
8 microgrids and fault location technology that will be developed during the project
9 will further isolate the ground and continue to provide power to customers from
10 outside the isolation area.

11

12 **Q101. Why is the Company focused on microgrid development and deployment?**

13 A101. The DOE's vision includes microgrids as a building block for the future electrical
14 system⁸. Microgrids provide a mechanism to bring local DER together to provide
15 solutions for resilience and reliability by becoming their natural aggregation point.
16 Microgrids form a unit that hosts loads and generation that can be connected or
17 disconnected from the rest of the grid. Additionally, multiple neighboring
18 microgrids with dynamic boundaries can form larger multi-customer dynamic
19 microgrids.

20

⁸“By 2035, microgrids are envisioned to be essential building blocks of the future electricity delivery system to support resilience, decarbonization, and affordability. Microgrids will be increasingly important for integration and aggregation of high penetration distributed energy resources. Microgrids will accelerate the transformation toward a more distributed and flexible architecture in a socially equitable and secure manner.” from DOE OE 2021 Strategy White Papers on Microgrids: Microgrids as a Building Block for Future Grids – Topic 4, page 5, Available at <https://www.energy.gov/sites/default/files/2022-12/Topic4%20Report.pdf>, Accessed on November 28, 2023.

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1 With that background, microgrids provide an opportunity to increase the benefits
2 of the Company's NWA deployments and customers' DER installations. Deploying
3 microgrids is directly aligned with the DOE's vision for the future electrical
4 distribution system.

5

6 **Q102. What are Adaptive Networked Microgrids (ANMs)?**

7 A102. Adaptive Networked Microgrids are two or more neighboring microgrids with
8 controls and protection that enable them to merge based on several considerations
9 including but not limited to the locations of faults, load forecasts, weather forecasts,
10 and DER status. These microgrids can dynamically change their boundaries
11 through switching operations to isolate faults and improve the reliability of
12 customers. This vision offers a chance to increase reliability, but development and
13 testing are required.

14

15 **Q103. What development and testing are needed?**

16 A103. There are seven areas of focus for the development and testing leading up to the
17 installations at O'Shea and Port Austin. This work is needed primarily to build on
18 the Company's NWA pilots toward ANMs. The seven areas are Project and
19 Technical Management, Sensors and Data Analytics, Cybersecurity, Control and
20 Protection, Engineering Due Diligence, Microgrid Deployment, and Sharing
21 Lessons Learned. Details on these seven areas can be found in Exhibit A-12,
22 Schedule 5.4.9, Section 2(a).

23

24 **Q104. How will the Company's customers benefit from this project?**

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1 A104. Benefits to the Company's customers include (a) greater resilience to extreme
2 weather conditions, (b) improved reliability for everyday operations, (c) enhanced
3 security from an evolving number of cyber-physical threats, (d) superior flexibility
4 to respond to the variability and uncertainty of conditions, and (e) increased
5 sustainability through energy efficient and renewable resources. Additionally, the
6 project will support the advancement of microgrids in general. Other technology,
7 such as fault locating and state estimation will be developed from the project, that
8 will benefit customers outside of the networked microgrid deployment. Overall,
9 this will place Michigan as a leader in Adaptive Networked Microgrid technology.

10

11 **Q105. Does the Company have any partners for this project?**

12 A105. Yes. The Company has formed a partnership for this work called the Adaptive
13 Networked Microgrid Partnership (ANMP). The Company's partners include Open
14 Systems International (OSI), Open Energy Solutions (OES), Electric Power
15 Research Institute (EPRI), and the University of Michigan-Dearborn. Lawrence
16 Livermore National Laboratory (LLNL) and National Renewable Energy
17 Laboratory (NREL) are advisors for the project. The roles of each partner are
18 described in Exhibit A-12, Schedule B5.4.9 Revised.

19

20 **Q106. Where will this new technology be deployed initially?**

21 A106. After a period of development and testing at the Company's Solar and Storage Lab
22 in Westland, Michigan, the deployments will be at Chicago substation/O'Shea
23 Solar Park and Port Austin substation.

24

25 **Q107. What specifically will be added at Chicago/O'Shea?**

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1 A107. One of the batteries currently being used for the Omega Pilot will be transported to
2 a new DER site to be installed on Chicago DC 1415 in the City of Detroit.
3 Reclosers will be installed at the start of the circuit to isolate grounds, at each DER
4 site, and on the circuit to isolate or connect the two DER sites to create dynamic
5 microgrids.

6

7 **Q108. What specifically will be completed at Port Austin?**

8 A108. A DER site with a battery only will be installed adjacent to the microgrid currently
9 being installed. Depending on equipment availability and cost, an additional DER
10 site may be built next to the substation with solar and storage like the current DER
11 being installed at Port Austin. Like the plan for Chicago/O'Shea, these DER sites
12 will all be sectionalized by reclosers to dynamically shift the microgrid boundaries.
13 There will also be sectionalizing at the beginning of the circuit for ground fault
14 indication and isolation.

15

16 **Q109. What are the expected costs for this work?**

17 A109. The estimate for the pilot is approximately \$46 million. This includes
18 approximately \$1 million in funding from the Company's partners, and \$23 million
19 from the DOE, which leaves approximately \$22 million in funding from DTE
20 Electric.

21

22 **Q110. What is the schedule for this networked microgrid development work?**

23 A110. The project is expected to progress over four phases that are roughly tied to the
24 calendar years from 2024 to 2027. With the Engineering Phase primarily occurring
25 in 2024, the Development Phase primarily occurring in 2025, the Deployment

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1 Phase primarily occurring in 2026, and the Assessment Phase primarily occurring
2 in 2027.

3

4 **Q111. How is the funding provided by the DOE and the Company's partners**
5 **included in the Exhibit A-12, Schedule B5.4?**

6 A111. Line 26 on page 17 of Exhibit A-12, Schedule B5.4 provide the cost for the project.
7 The funding from the DOE and the Company's partners to support the project is on
8 line 27 on page 17 of Exhibit A-12, Schedule B5.4. Line 27 reduces the total cost
9 of the project, which is included on Line 26.

10

11 **Q112. What does the Order Case No. U-21297 include about Staff involvement for**
12 **the NWA pilots?**

13 A112. Page 124 of the December 1, 2023, Order in Case No. U-21297 includes the Staff's
14 recommendation that "the company engage in ongoing consultation with the Staff
15 and making other recommendations for the battery technology pilots and for
16 ongoing updates that could ease the burden of litigating these pilots in rate cases."
17 The Company has continued to involve Staff with NWA pilots. As an example, for
18 the Adaptive Networked Microgrid, the Company presented the pilot to the Staff
19 on November 14th, 2023, to ensure the Staff understands the concept and has an
20 opportunity to offer their insights on the pilot.

21

22 **E. Grid Edge Insights and New Technology**

23 **Q113. What is Grid Edge Insights and New Technology?**

24 A113. This category of investments is a collection of projects that are designed to
25 consolidate the learnings from the Non-Wire Alternatives projects into a consistent

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1 platform, and to unlock the capabilities of new equipment that is being brought to
2 market to run the grid safer, more reliably and efficiently, ultimately increasing the
3 amount of DER that can be accommodated on the grid. The projects that make up
4 this category are summarized in the following table.

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1 **Table 4 Key Investment Highlights for Grid Edge Insights and New Technology**

Key Investment	Use Case	Implementation Highlight
Grid Edge Insights	Consolidate capabilities developed in the NWA projects into a single modular platform to allow future NWA and DER installations to benefit from consistent technology, controls, communications and practices	Creation of a single interconnection gateway platform for all large interconnection and NWA projects. The platform will have a number of physical form factors to allow for deployment at small medium and large scale sites.
New Technology Evaluation	Test overhead, underground, substation and control equipment that is not currently in use at DTE to determine if it can be used to improve current operations. Create practices and procedures for the roll out of the technology into projects and programs.	All new equipment that will be operated and maintained by DTE Electric is run through the New Technology evaluation 6 gate process to ensure appropriate documentation, standards and procedures are created including installation at the Technical Training Center and field evaluations prior to broad deployment.
DER Control	Installation of standardized interconnection gateways at several DTE DER sites	Upgrades of controls and monitoring at Demille, Turill and Greenwood solar to improve remote management capabilities, integration with the control room and forecasting.
Small Solar and Storage Testbed	Testing hardware and capabilities to evaluate the performance and safety of commercially available solar and storage that customers are installing in the service territory and evaluate different configurations for interactions, safety and training for field crews.	Testing of customer DER configurations in a safe environment and enable the creation of practices and settings for smart inverter and microgrid functions for customers that install DER.
Sensor network and algorithm Development	Evaluate different remote sensing options to capture information that allows for improved forecasting and visibility into DER performance	Installation of weather network sensors and sky cameras to improve hourly forecasts of solar production in localized areas that have high solar penetration allowing the control to better understand fluctuations in loading.

2

3 **Q114. What are the benefits of Grid Edge Insights and New Technology?**

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1 A114. Evaluation and integration of new technology into the grid allows for technological
2 enhancements to improve grid reliability, resilience, safety, efficiency, and
3 opportunities for costs savings. The investments in Grid Edge Enablement will
4 allow for additional NWA and DER resources to be connected into the grid in a
5 safe and reliable manner by coordinating the DER controls with day-to-day grid
6 operations. By having a consistent platform for integration, per project costs and
7 time are reduced as site and controls design is limited to only those unique aspects
8 of the DER that do not follow standard protocols and interoperability. Integration
9 of Utility NWA and DER can be standardized, and interconnection of customer
10 DER can be streamlined as substantial portions of the communication and control
11 are pre-designed inside the gateway. The gateway allows for a consistent
12 configuration, communications, and cybersecurity between the utility and the
13 gateway and moves the complexity of dealing with site-by-site variation in
14 hardware and implementation to the edge of the grid rather than having to
15 accommodate the additional complexity in central IT systems like the ADMS and
16 future Distributed Energy Resource Management System (DERMS). The modular
17 nature of the gateway controls allows for expandability to accommodate new DER
18 types, control algorithms, and functionalities and the system provides the ability for
19 remote management and upgrades to reduce site visits.

20

21 **Q115. What considerations inform the Company's strategy for Grid Edge Insights**
22 **and New Technology?**

23 A115. New technology is evaluated on several factors, with reliability and safety of the
24 product taking precedence. The new technology process allows for a structured
25 evaluation of all aspects of a product or functionality and for incorporation of

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1 lessons learned from other utilities, industries, and research organizations like
2 EPRI. These lessons inform the determination of its readiness to be deployed into
3 the grid. Careful attention is given to operating practices, worker safety, and the
4 long-term sustainability of the product. Key aspects considered are the ability for
5 the product and its controls to be integrated into the DTEE SCADA system and the
6 cyber security of the product and its vendor support structure. This process allows
7 for products and functionalities to be accepted and operating practices to be
8 developed; it also provides the opportunity to identify any cross-cutting synergies
9 in other areas where the same product or functionality can be reused to save costs.
10 Other considerations include enabling additional capabilities for utility operations
11 and customers to improve efficiency, reliability, and resilience. These factors can
12 then be tested at the Technical Training Center which includes facilities for testing
13 grid connected and the interactions of customer equipment at the Solar and Storage
14 Testbed.

15

16 **Q116. What is the Company's strategic scope for Grid Edge Insights and New**
17 **Technology?**

18 A116. Ongoing investments in this category are expected as the complexity of the grid
19 and the capability of devices will continue to increase for decades to come as new
20 technology is brought to the marketplace. A rigorous technology evaluation and
21 selection program is instrumental in selecting the best technologies to construct the
22 grid and to ensuring safe, reliable, and efficient operation for customers and
23 employees. Investments in the introduction of new technology allow all projects
24 and programs to benefit from improved performance and capabilities. For example,
25 the pace of change of consumer DER products continues to increase and utility

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1 practices must keep up with customer expectations. As the industry adapts to these
2 changes it is expected that there will be increased standardization in products and
3 the need for increased communication between the customer and utility; this will
4 drive additional requirements for interoperability and cyber security to unlock the
5 full potential of DER and NWA and additional testing capability for the Solar and
6 storage testbed to incorporate microgrid control functionality.

7

8 **Q117. Were all capital investments in Grid Edge Enablement and New Technology**
9 **described within the Distribution Automation financial exhibit?**

10 A117. No. In 2022 and 2023, investment occurred under the OT program titled
11 Interconnection Process Enablement. For 2024 this is described in The Operational
12 Technology Distribution Planning section of this testimony. Investment for 2022
13 was \$1.64 million and for 2023 \$2.75 million, most of this being expansion of the
14 small solar and storage testbed site to incorporate three phase 480V and medium
15 voltage testing capability and gateway testing hardware. These investments were
16 made under that category prior to the decision to split the DER controls and
17 hardware from the backend OT functionalities needed for interconnection study and
18 processing. For 2024 onward all the control and hardware investment will be
19 included in the Grid Edge Enablement and New Technology Category. This work
20 was not duplicative and simply represents a change in classification to align the
21 projects more clearly to their focuses going forward. Work incorporated into the
22 individual NWA projects reflects site specific implementations and while it is
23 coordinated with the Grid Edge Enablement and new technology the investment is
24 not duplicated between the projects.

25

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1 **Q118. What progress has been made in 2022 and 2023?**

2 A118. The solar and storage testbed has been expanded to allow for connection and testing
3 of the interconnection gateways and battery trailer system. This expansion included
4 test bays with medium voltage hookups, conduit, cable and switching equipment as
5 well as communication and control wiring to allow for instrumentation and
6 connection to the equipment.

7 The large interconnection gateway has been tested at the Solar Testbed and
8 equipment is being prepared to be deployed to NWA projects such as O'Shea, and
9 Port Austin. A variant has also been incorporated into the Battery Trailer systems.
10 Grid edge functionalities for energy storage management and coordination between
11 the utility control room and market operations were implemented into the gateway
12 functionality along with safety and operating controls that allow for monitoring
13 DER, energy storage systems, and alarms.

14 A Hardware-In-the-Loop (HIL) testing system has been installed in the testbed
15 which allows for real time and repeatable testing of control and communications
16 interactions of the actual grid control hardware while allowing for different circuit
17 configurations and scenarios to be simulated. This functionality allows testing of
18 complex control schemes leading to a high degree of confidence that the controls
19 will work when deployed to the field. It also allows for rigorous testing of scenarios
20 where changes in settings or conditions change; the tests can be rapidly rerun to
21 verify that proper system operation will occur. This type of testing is critical to
22 advanced functions such as microgrids where many devices must all operate
23 together over different networks to allow for the successful transition of customers
24 and resources onto and off the grid.

25

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1 **Q119. What are the benefits of the 2022 and 2023 investments?**

2 A119. Having a consistent design for the interconnection gateway allowed for NWA
3 projects to incorporate the concrete pad, house service power, and communications
4 requirements into the site plan with minimal design. The modular controls
5 capability allowed each project to only focus on the unique aspect of the project
6 design and use cases, significantly reducing engineering and design time and
7 eliminating duplicated effort. The HIL system has already allowed for rapid
8 verification of control concepts for NWA projects like the microgrid NWA at Port
9 Austin.

10

11 **Q120. What is the Company's plan for 2024 and 2025?**

12 A120. Investments in 2024 and 2025 include integrations into the interconnection gateway
13 of functionalities for microgrid operations, networked microgrid capabilities,
14 coordination with grid automation, the inclusion of customer managed DER into
15 grid optimization, EV and V2G management and Demand Response. Additionally,
16 medium and small-scale gateway products will be evaluated and tested to allow
17 more DER and NWA sites to benefit from the integrated gateway functionality.
18 New technology evaluations will continue to expand the capabilities of grid
19 automation to allow for more integration with ADMS FLISR, circuit loop schemes
20 and distribution automation. Investment in gateways and sensor networks will
21 establish a mechanism to replace the system loading visibility that is lost in no
22 longer being able to install generation meters for specific customer classes. The
23 testbed will also be enhanced to allow for the full training capabilities on customer
24 DER configurations and testing of microgrid functionalities for NWA projects like
25 the ANM using both the HIL simulation system and the testbed electrical network.

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1 **Q121. What benefits are associated with the work planned for 2024 to 2025?**

2 A121. New Technology evaluations in 2024 and 2025 will focus on supporting grid
3 automation deployments and the various use cases for the viper reclosers and
4 ADMS advanced functions such as CVR/VVO and FLISR. Additional
5 standardization and practices for distribution connected energy storage and
6 microgrids will be established. The investments in 2024 and 2025 will substantially
7 increase the ability for the Company to integrate both utility and customer owned
8 DER into grid operations and will streamline portions of the design and engineering
9 for large customer interconnections. Optimization algorithms will be implemented
10 to allow for more flexible DER operation and increased levels of DER and storage
11 penetration into the distribution system. The HIL system and testbed will be utilized
12 to validate that this new technology and functionality works together without
13 creating unexpected operating behavior.

14

15 **F. Distribution Sensing and Monitoring (includg Line Sensors)**

16 **Q122. What are Distribution Line Sensors?**

17 A122. Distribution Line Sensors are devices used to monitor the real time status of the
18 distribution system and provide critical information to field personnel and system
19 control room operators to help them better monitor and manage the grid.

20

21 **Q123. What is the scope of the Distribution Line Sensors Program?**

22 A123. This program includes overhead system sensors used to monitor power quality and
23 fault data needed for real time load transfer analysis, fault locating, and system
24 status and Underground Residential Distribution (URD) sensors for use in
25 underground area to quickly direct field crews to fault underground sections to

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1 improve isolation and restoration times. This program will also include a
2 technology demonstration of new sensors intended to help monitor the system for
3 broken pole and wire-downs, allowing dispatchers to better locate and differentiate
4 between energized and deenergized wire-downs as well as down electrical lines
5 versus joint use wires.

6

7 **Q124. What are the benefits of Distribution Line Sensors?**

8 A124. Distribution line sensors support faster outage restoration by helping to identify and
9 locate faults, and dispatching crews to the identified fault location. Line sensors
10 located at manual switches, crossings or other operating locations indicate to the
11 control room that the fault has occurred beyond the device and a crew can be
12 dispatched to the location, first to immediately restore portions of the circuit then
13 to begin patrolling for the specific fault location from the line sensor location.
14 Visual indication on the line sensors also helps crews quickly identify faulted lines
15 when in the field. Many of the line sensors also collect loading and voltage data
16 that can be sent directly to the ADMS and fault information that can be used in the
17 ADMS advanced distribution applications like FLISR which contributes to
18 reducing outage duration for customers. The line sensors work with the
19 telecommunications system, described earlier in my testimony, to provide power
20 and fault information to the ESOC and engineering personnel via the ADMS
21 system.

22

23 **Q125. What work was completed in 2023?**

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1 A125. 398 underground (UG) line sensors and 100 overhead sensors were installed.
2 Additionally, 300 pole sensors and 1000 overhead line sensors were purchased that
3 will be installed in 2024.

4
5 **Q126. What is the scope of work for the Distribution Line Sensors Program for 2024**
6 **and 2025?**

7 A126. In 2024, 500 overhead line sensors will be installed, and 300 pole sensors will be
8 installed and to test sensor ability to detect wire-downs. In 2025 the remaining
9 overhead sensors and 1300 underground sensors will be installed.

10

11 **Operational Technology**

12 **Q127. How does DTE Electric structure its distribution technology investments?**

13 A127. Two primary areas make up the bulk of the DTE Electric distribution technology
14 investments: Corporate Technology investments which make up the majority of
15 traditional Information Technology (IT) assets, and Operational Technology (OT),
16 those investments made specifically within a major operating unit, such as
17 Distribution Operations.

18

19 DTEE's (2023) Distribution Grid Plan (DGP) covers technology investments
20 specifically related to Grid Planning stating, "Implementing new information
21 technology (IT) and operational technology (OT) will streamline and optimize the
22 Company's planning while also improving safety and productivity. These
23 investments form the core of the Technology and Automation Pillar." (Exhibit: A-
24 23, Schedule M8, p. 129) The DGP forms the basis for a roadmap of technology
25 investments categorized into five (5) areas: Grid Management, Distribution

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1 Planning, Work Management and Scheduling, Asset Management, and Mobile
2 Technology. These investment categories serve to organize individual investments
3 and will be discussed in detail in this testimony.

4

5 This structure forms the underlying basis for planning and aligning the Company's
6 technology investments over a 5+ year planning horizon and is the foundation for
7 any updates or changes to this strategy as they represent the Company's technology
8 investment.

9

10 **Q128. How does planning for technology investments differ from the planning of**
11 **more traditional equipment investments in the context of distribution grid**
12 **planning?**

13 A128. In navigating technology investments for distribution grid planning, it is crucial to
14 recognize the shared planning aspects with traditional equipment investments.
15 However, what sets technology investments apart are two key distinctions: the
16 inherent dynamism, demanding adaptability due to rapid pace of technology
17 change, and the ongoing deployed lifecycle, necessitating a nuanced strategy for
18 balancing continuous optimization and evolution with prudent investment
19 planning. Ongoing investments are necessary to address the changing technology
20 landscape and take advantage of new functionality that delivers benefits to the
21 customers.

22 • Rapid pace of technology change: Many capital investments like transformers,
23 switchgear, and conductors have useful design lives that are measured in
24 decades. These devices routinely spend their entire service lives without in-
25 place updates or changes and usually do not need to be altered once deployed

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1 until they reach end of life. Technology assets are different . The services,
2 features, and benefits provided by an asset often stem from its capability to
3 adjust technology through remote programming or updating capabilities in
4 place. It is that capability that delivers ongoing value to that asset yet makes
5 planning for changes an asset may undergo over time a unique challenge.
6 Technology asset change cycles are measured in months, quarters, or years, not
7 in multiples of decades. Thus, the planned state for a system or technology can
8 change rapidly, sometimes even over the course of initial deployment or shortly
9 thereafter. This is an advantage rather than a weakness, but it challenges the
10 concept that all these changes can be known prior to initially building and
11 implementing these investments.

- 12 • Deployed lifecycle: The term deployed lifecycle refers to the various stages
13 and processes involved in deploying a software application or system. Each
14 phase, for example development, testing, deployment, monitoring, and
15 maintenance, contributes to the overall lifecycle ensuring a smooth and
16 effective deployment of software. Technology investments can have shorter
17 deployed lifecycles than other grid assets. The Company invests in advancing
18 technology, bringing it closer to customers as analog devices transition to
19 digital. Examples of this are modern grid control devices like reclosers and
20 meters, both of which have become computers in their own right. As more of
21 the elements of those investments achieve greater sophistication in terms of
22 computing responsibilities, the Company's need to protect them from the
23 physical and cyber perspectives increases. Many of the field devices have and
24 will continue to undergo rapid advances in capability. As the Company and
25 customers demand faster and more capable service, they will need to be cycled

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1 in and out of service faster than their less capable predecessors. Just as there
2 are very few 20-year-old computers in homes, so too will the Company's utility
3 automation and technology investments need to be kept up to date more often
4 than the strictly mechanical devices deployed in the past.

5 To be successful in technology planning the Company must stay abreast of evolving
6 technologies, incorporate new functionalities, and address emerging challenges.
7 Continuous investment allows for the integration of innovations that deliver value
8 to customers, such as improved reliability, and better response to dynamic grid
9 conditions.

10

11 **Q129. Are there any additional differences to consider when planning for technology**
12 **investments and the planning of more traditional equipment investments in**
13 **the context of distribution grid planning?**

14 A129. Yes. Other differences to consider include:

- 15 • External vulnerabilities: Any device placed into the grid infrastructure must be
16 protected. Various devices in the electric grid require security measures,
17 including Supervisory Control and Data Acquisition (SCADA) systems,
18 routers, switches, smart meters, and communication networks. Protecting these
19 devices is crucial to ensure the reliability and integrity of the grid. In the past,
20 when devices were largely electro-mechanical, those security needs were
21 primarily focused on preventing physical tampering and ensuring public safety.
22 Today, when an advanced technological device is placed into service that need
23 for protection goes beyond the physical, the company must now also prepare
24 for cyber threats. Cyber threats are very real, and when they happen can be
25 impactful and expensive. There is as much innovation and improvement going

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1 on in that arena as there is in the improvement of the technologies' actual
2 purpose. As these threats gain sophistication, they can drastically affect the
3 useful life of an investment. These threats may in some cases force the
4 Company to modify or replace devices or systems prematurely when threats or
5 methods unknown in the industry at installation emerge. Increased frequency
6 of changes to address these threats are expected as indicated by the February
7 2024 testimony by the FBI and CISA (Critical Infrastructure Security Agency)
8 to Congress⁹ on the active attacks by foreign nation states on domestic critical
9 infrastructure.

- 10 • Industry Advances: Many of this industry's traditional suppliers understand
11 utility investment cycles and design products with those long replacement
12 cycles in mind. Technology investments are very different in that the
13 components, standards, devices, and methods cross multiple industries,
14 minimizing the chance of supplier partners slowing the pace of their innovation
15 or product improvements. This difference often directly impacts how often the
16 company replans investments, as newer versions and capabilities overtake
17 deployed solutions and require investment to keep pace.

18

19 These factors underscore the necessity for the Company to consistently review and
20 adapt existing plans, occasionally expanding the scope of an investment shortly
21 after, or even during, a technology deployment.

22

⁹ Testimony of Dr. Charles Clancy available at <https://www.congress.gov/118/meeting/house/116802/witnesses/HHRG-118-HM08-Wstate-ClancyC-20240206.pdf>, accessed February 22, 2024

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1 **Q130. How do the inherent differences in technology life cycles impact the timing of**
2 **design requirements in a technology deployment?**

3 A130. The inherent differences in technology life cycles can influence the timing of design
4 requirements in a technology deployment by necessitating adjustments to align with
5 evolving technology advancements and industry standards. Unlike standard capital
6 investments with relatively stable design parameters, technology life cycles
7 demand a heightened responsiveness to changing industry landscapes. This
8 dynamic environment impacts the need for updates, adaptations, and new features.
9 With solid practices and process and an agile and iterative approach to design, the
10 Company ensures that technology remains effective and aligned with current
11 standards throughout its deployment.

12

13 **Q131. Does the Company ever change scope of OT projects in order to capture**
14 **additional benefits?**

15 A131. Yes. While the above questions pertain to all of OT planning, there are two specific
16 areas contained in this testimony where scope was changed to achieve additional
17 benefits. They are discussed below in Other Modernize Grid Management and
18 Customer Power Status Visibility Project.

19

20 **Q132. What are the major categories of Operational Technology investments?**

21 A132. OT investments are aligned to five major categories:

- 22 • Grid Management
- 23 • Distribution Planning
- 24 • Work Management & Scheduling
- 25 • Asset Management

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- 1 • Mobile Technology

2

3 **G. Grid Management**

4 **Q133. What is Grid Management?**

5 A133. Grid Management is a category of investments that enable the Company to monitor,
6 control and optimize the operation of Grid Automation investments. These projects
7 include the full suite of ADMS distribution management applications, including
8 outage response, fault location, isolation, and service restoration (FLISR), and
9 advanced control toolsets. Investments in this category enable distribution
10 operators to model the real-time state of the electrical system and manage the entire
11 distribution network. This includes systems that monitor and control the power
12 system, manage planned and unplanned outages, and analyze and optimize the
13 quality and reliability of the network. These investments also include the platforms
14 that will enable the management of Distributed Energy Resources (DER) such as
15 the DERMS (Distributed Energy Resource Management System).

16

17 **Q134. What are the key drivers for the Grid Management investments?**

18 A134. The key drivers for the Company's grid management investment include the need
19 for:

- 20 • Cybersecurity: Investing in cybersecurity measures to protect against potential
21 threats to the grid's infrastructure.
- 22 • Electrification: Supporting the growth of electric vehicles and other electrified
23 technologies, which drives changes in grid capacity and management.
- 24 • Demand Response: Implementing strategies to match electricity consumption
25 with supply to optimize grid performance.

Line
No.

- 1 • Renewable Integration: Adapting the grid to incorporate renewable energy
- 2 sources and manage their grid impacts and intermittent nature.
- 3 • Reliability and Resiliency: Ensuring both a stable and reliable power supply to
- 4 meet increasing demand and reduce outages, while enhancing the grids' ability
- 5 to withstand and recover from disruptions or cyber-attacks.

6 Collectively these key drivers create the need for grid management solutions.

7

8 **Q135. Where are the capital investment details of the projects and programs in the**
9 **Grid Management category?**

10 A135. Capital investment details of these projects and programs in this category of the
11 instant case can be found in:

- 12 • Exhibit A-12, Schedule B5.4, page 17-18
- 13 • Exhibit A-23, Schedule M7

Line
No.

1

Table 5 Grid Management Exhibit Locations

Program/Project	Exhibit A-12 Sch. B5.4	Exhibit A-23 Schedule M7	Exhibit A-23 Schedule M8
SOC: ESOC	p. 17, line 4	pp. 189-192	pp. 145-150
SOC: ASOC	p. 17, line 5	pp. 185-188	pp. 145-150
ADMS: DMS/OMS	p. 17, line 3	pp. 8-11	pp. 145-150
Other Modernize Grid Management	p. 18, line 40	pp. 164-168	pp. 145-150
ADMS Enhancements	p. 18, line 32	pp. 4-7	pp. 145-150
Operational Technology and EFC	p. 18, line 33	pp. 158-163	pp. 145-150
Customer Power Status Visibility	p. 17, line 18	pp. 29-33	pp. 145-150
AMI: Meter Communications Upgrade	p. 17, line 17	pp. 17-20	pp. 145-150
Microwave End of Life	p. 18, line 39	pp. 104-107	pp. 145-150
FLISR Implementation	p. 18, line 35	pp. 70-73	pp. 145-150
DERMS	p. 18, line 36	pp. 42-45	pp. 145-150, 241-242
Substation Cybersecurity	p. 18, line 37	pp. 193-196	pp. 148, 243
Automation Configuration and Test Record Database	p. 18, line 38	pp. 25-28	pp. 148-149, 243
Meter Improvements	p. 18, line 34	pp. 100-103	pp. 145-150

2

3 **System Operations Center (SOC) and Alternative System Operations Center**4 **(ASOC) Projects**5 **Q136. What is the SOC Modernization Project?**

6 A136. The SOC Modernization project replaced the Company's previous outdated
7 primary SOC and the smaller, outdated backup SOC by constructing two facilities
8 designed using current security, resiliency, and operability standards. The two new
9 facilities are called the Electric System Operations Center (ESOC), which was
10 essentially completed and fully occupied as of February 2022, and the Alternate

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1 System Operations Center (ASOC) which certification will be complete in third
2 quarter 2024. The previous SOC and backup SOC had significant limitations,
3 which I will describe later in my testimony.

4

5 **Q137. What are the essential functions of a SOC?**

6 A137. The SOC is the most critical facility in Distribution Operations. Personnel in the
7 SOC operate the subtransmission and distribution system in southeast Michigan,
8 and additionally support generation operations. SOC System Supervisors are the
9 ultimate authority for the DTE electrical system operation with the goal of
10 maintaining safety of the field personnel and public, reliability of the electrical grid
11 and the continuity of service to the customers. They monitor system conditions
12 including alarms, and direct field personnel to safely operate electrical equipment
13 for routine switching needed for maintenance, other planned activities, and for
14 outage restoration. The SOC also coordinates with Electric Dispatch personnel to
15 ensure appropriate crews are assigned to address system issues.

16

17 As a NERC registered Generator Operator (GOP) and Local Balancing Authority
18 (LBA) the ESOC employees are also required to maintain the reliability and safety
19 of the Bulk Electric System (BES) through coordination with the DTE Merchant
20 Operations Center (MOC), and the Transmission Operator (ITC). Certified NERC
21 operators in ESOC work closely with MISO, MOC, and the ITC to ensure system
22 generation and load levels are kept in balance along with ensuring customer
23 utilization voltage levels are maintained to prevent damage to customers
24 equipment, ensure their critical processes operate as needed, and maintaining
25 customer satisfaction with reliable power.

Line
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1 **Q138. Why was the SOC Modernization project needed to replace the previous SOC**
2 **facility?**

3 A138. The former SOC had several critical limitations, which DTE Electric identified
4 through extensive benchmarking at the inception of this project. These critical
5 limitations included DTE Electric's outdated facility with physical, manual
6 visualization methods, end of life legacy technology that was no longer receiving
7 necessary support and updates, space limitations to support future growth for
8 critical reliability functions and limited visibility into the performance of
9 supporting telecommunication infrastructure. The transformation from a manual
10 state to a modern automated approach was imperative to address these challenges
11 effectively.

12

13 **Q139. What is the status of ESOC?**

14 A139. ESOC integration has been successfully completed and integrated into full
15 operations.

16

17 **Q140. What is the ASOC?**

18 A140. The ASOC will be the NERC required alternate backup redundant control center to
19 the ESOC. Located inside the recently constructed Waterford Service Center it is
20 comprised of approximately 16,300 square feet with back-up generation and double
21 redundancy for wireless and internet capabilities. Construction on the Waterford
22 Service Center in Waterford, Michigan, began in November 2022.

23

24 This facility will include electronic displays and software/hardware that meet
25 dispatcher and operator needs and mimic the current ESOC standards. This will

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1 allow for a fully functioning, alternate location to carry-on the activities of the
2 current Headquarters ESOC seamlessly, in the event of an emergency, as well as
3 provide for the future training/re-training and testing of Electric System Operation
4 Center employees.

5

6 **Q141. With the completion of the new ESOC, is a new backup facility (ASOC) still**
7 **needed?**

8 A141. Yes. Without an alternate facility available in the event of a disruption at ESOC,
9 recovering from a storm or other disaster would be extraordinarily challenging, and
10 delay restoration. The reasons for building a new modernized backup facility have
11 not changed since the Commission originally approved building a new ASOC in
12 Case No. U-20561. Given the critical nature of the ESOC in operating the electric
13 infrastructure, under any emergency conditions, a backup facility is required in the
14 event the primary facility is inoperable. While the Company does utilize the current
15 backup SOC on occasion, the facility is inadequate for sustained operations, and
16 for disaster recovery efforts.

17

18 **Q142. Has the MPSC ruled on the costs for the ASOC?**

19 A142. Yes. On Page 119 of the December 1, 2023 Order in Case No. U-21297 the MPSC
20 stated that “the Commission finds that the proposed ASOC spending is reasonable
21 and prudent,” and the amount requested by the Company was approved.

22

23 **Q143. What is the status of the ASOC project?**

24 A143. The construction portion of the ASOC buildout was completed in December of
25 2023, and completion of the technology build out of the space and interior

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1 construction will continue into the 2nd quarter of 2024. The ASOC is expected to
2 achieve full NERC certification in 3rd quarter of 2024.

3

4 **Q144. How will customers benefit from the total SOC Modernization project?**

5 A144. Customers will benefit from the SOC Modernization project's two facilities (ESOC
6 and ASOC) due to the improved communication paths between the resources that
7 will be co-located in the new facilities. This will provide quicker and improved
8 coordination to create and implement restoration strategies more effectively. In
9 addition, customers will benefit from reduced risk of disruption in operations
10 during outage events, and faster restoration times regardless of the facility from
11 which the System Operations organization operates from. The ability to understand
12 system conditions, and dispatch resources to address issues, will be greatly
13 enhanced by the technology available in the new facilities and the co-location of
14 the System Operators, Power Dispatchers, and support personnel. In addition,
15 ESOC is more resilient and hardened to withstand adverse natural and man-made
16 disasters, allowing electric grid operations to recover much more quickly in the
17 event of a major catastrophe. These benefits have already started to materialize due
18 to the utilization of the ESOC and will be fully realized once the ASOC is complete.

19

20 **Advanced Distribution Management System (ADMS) Distribution Management**

21 **System (DMS)/Outage Management System (OMS)**

22 **Q145. What is ADMS DMS/OMS?**

23 A145. The Advanced Distribution Management System (ADMS) is a modern operating
24 technology platform that is essential to the Company's grid modernization efforts
25 which improves system reliability and operational efficiency. These software

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1 solutions are used to monitor, control, and optimize the distribution of electricity in
2 real-time. ADMS combines Distribution Management System (DMS) and Outage
3 Management System (OMS) functionalities to enhance the overall management of
4 power distribution networks. The series of systems that comprise the ADMS
5 platform represents a significant advance in the Company's situational awareness
6 of grid condition, coordination of system operators and field personnel, and control
7 of grid assets. It provides a consistent integrated view of the system to all
8 organizations, supports faster restoration times, and allows for improved
9 monitoring and control of the distribution system.

10

11 DMS is the Distribution Management System, which provides a complete network
12 model of the electrical system for operators to view operating conditions in real
13 time. DMS consists of multiple applications such as the Network Model (eMap),
14 Distribution Power Flow (DPF), Distribution State Estimation (DSE), and
15 applications with more advanced functionality such as Fault Location, Isolation,
16 and Service Restoration (FLISR), Volt/Var Control (VVC), Conservation Voltage
17 Reduction (CVR), Feeder Reconfiguration (FR), and electronic Switch Order
18 Management (SOM).

19

20 OMS is the Outage Management System, which aggregates emergent trouble
21 information reported by customers and AMI meters and allows system operators
22 and dispatchers to prioritize response and properly assign crews for repairs,
23 enhancing their ability to manage and minimize disruptions in service for
24 customers.

25

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1 **Q146. Has the MPSC ruled on ADMS: DMS/OMS?**

2 A146. Yes, on page 114 of its Order dated December 1, 2023 in Case No. U-21297, the
3 Commission approved DTE Electric's requested expenditure for this component of
4 ADMS, agreeing that outage restoration response is a critical area stating that, "the
5 company took reasonable steps to address the problems with the DMS/OMS in light
6 of the available options and approves DTE Electric's requested expenditure for
7 inclusion in rate base."

8

9 **Q147. What was the scope of work completed in 2023 for ADMS: DMS/OMS?**

10 A147. DMS and OMS went live in February of 2023. Prior to go-live, the Company ran
11 parallel operations for OMS where a subset of operations users used the new tool
12 in parallel with the old tool to prepare for go-live. After go-live the Company
13 moved into the hypercare phase of the project. Hypercare was an intense and
14 focused phase of support and monitoring that immediately followed go-live. It
15 involved round-the-clock support for system operations and field personnel as they
16 became accustomed to operating the new systems. Additionally, EMS (Energy
17 Management System), which is a software solution that allows for monitoring,
18 control, and optimization of energy generation transmission, was upgraded at that
19 same time to bring the existing EMS to a compatible version with OMS and DMS.

20

21 **Q148. Given that DMS has gone live with OMS, have all DMS applications been**
22 **operationalized?**

23 A148. No. Although all DMS applications were deployed in February 2023, the Company
24 will continue to build upon this foundation by implementing additional modules
25 and enhancements throughout 2023 and beyond. At go-live, the eMap application

Line
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1 and SCADA integration with OMS immediately enabled more accurate and timely
2 outage event creation and situational awareness. Additional benefits will be
3 realized as the Network Model is tuned and penetration of SCADA devices in the
4 distribution grid increases. The investment to enable these remaining applications
5 over the next 3-5 years is found in the ADMS Enhancements and FLISR
6 Implementation line items in Exhibit A-12, Schedule B5.4, p.18, lines 32 and 35.
7 More information on those applications and benefits can be found later in the
8 ADMS Enhancements and FLISR Implementation sections of my testimony.

9

10 **Other Modernize Grid Management**

11 **Q149. What is Other Modernize Grid Management?**

12 A149. Other Modernize Grid Management is a category of investments that encompass a
13 diverse set of projects designed to enhance the Company's operational capabilities,
14 particularly during high-volume outage events, those that impact hundreds or
15 thousands of customers. From software improvements to licensing acquisitions,
16 each investment contributes uniquely to bolstering efficiency and resilience in the
17 Company's technology landscape.

18

19 **Q150. Were there any changes in this category of investment in 2023?**

20 A150. Yes. The Company's achievement on February 6, 2023, with the launch of the
21 comprehensive ADMS grid management set of tools marked a significant
22 milestone. During the subsequent catastrophic ice storm, the Company leveraged
23 the newly implemented system's breakthrough capabilities. Swiftly learning from
24 this experience, the Company promptly initiated targeted projects to improve storm
25 restoration and customer communications, integrating the lessons learned with the

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1 enhanced capabilities of the ADMS grid management tools. Early results showed
2 the initiatives implemented resulted in immediate improvements to:

- 3 • Outage analysis processing, enabling faster event creation and initiating the
4 restoration process for customers sooner.
- 5 • Momentary outage processing by improving the interfaces between ADMS
6 and our AMI network.
- 7 • Faster outage restoration by leveraging improvements to bulk event
8 updating and bulk crew assignment creation.

9 This highlights the system's adaptive response and its crucial role in optimizing
10 storm resilience efforts.

11

12 **Q151. What are the key investments in this category?**

13 A151. The key investments in this category are:

- 14 • OSI Licensing
- 15 • Qlik 3-year license purchase
- 16 • CT/VT High voltage, and test accuracy console
- 17 • EFC Communications
- 18 • Purchase of backhaul capable field area routers
- 19 • Pre-Storm ADMS Enhancements
- 20 • Post-Storm ADMS Enhancements

21

22 **Q152. Which projects in this category were initiated in 2023 to enhance storm**
23 **restoration and communication efforts?**

24 A152. The following projects were initiated to support storm restoration and customer
25 communication efforts:

Line
No.

- 1 • Pre-Storm ADMS Enhancements
- 2 • Post-Storm ADMS Enhancements
- 3 • EFC Communications
- 4

5 **Q153. What was the timing of the investment in these projects that were initiated to**
6 **enhance storm restoration and communication efforts?**

7 A153. These projects were swiftly initiated in 2023 in response to the severe storms and
8 new ADMS enabled technology to make improvements. These projects, crucial to
9 supporting storm restoration and communication, will continue in 2024 and
10 beyond. Future investments into these projects are listed in separate line items in
11 Exhibit A-12, Schedule B.5.4 as detailed in Table 6.

12

13 **Table 6 Future Investment Mapping of Storm Restoration Projects**

Projects Initiated in 2023	2023 Investment Exhibit A-12, Schedule B5.4 Location	Future Investment Exhibit A-12, Schedule B5.4 Location
EFC Communications	Line 40	Line 33
Pre-storm ADMS Enhancements	Line 40	Line 32
Post-Storm ADMS Enhancements	Line 40	Line 32

14

15 **Q154. Are any of the Other Grid Modernization projects discussed in other company**
16 **witness testimony?**

17 A154. Yes, the Error Free Communication (EFC) project is an Other Grid Modernization
18 project which is discussed in Part Six of Witness Hatsios' testimony. My testimony
19 will describe Other Modernize Grid Management excluding EFC. The table below
20 describes the breakout of Other Modernize Grid Management.

Line
No.

1 **Table 7 Other Modernize Grid Management by Year (\$000)**

Project	2022	2023	2024	2025
Other Modernize Grid Management excluding EFC	3,660	24,430	2,200	2,500
EFC	4,140	1,970	0	0
Total	7,800	26,400	2,200	2,500

2

3 **Q155. What is the OSI license investment?**

4 A155. The OSI license investment refers to a financially prudent investment as part of
5 Other Modernize Grid Management. Specifically, it entailed the acquisition of five
6 year on-premise licenses for the Company's Outage Management System, which is
7 mission-critical software.

8

9 **Q156. What are the key drivers and benefits of the OSI license investment?**

10 A156. This investment was an opportunity to purchase licenses on a 5-year term that
11 would reduce the cost of these licenses by ~\$1 million over that duration and shift
12 the warranty period to cover that entire term. This change will allow the Company
13 to save money and accurately project costs and ensure contractual service levels.
14 The savings realized in this area will reduce the overall investment need. The
15 enhanced warranty terms will benefit the Company's employees directly due to the
16 increased support priority the agreement brings, and therefore support the
17 Company's customers.

18

19 **Q157. What factors drove the timing of the OSI license investment?**

20 A157. This investment was undertaken now as the term of the current license and warranty
21 period was due to lapse in the 2023 calendar year, allowing immediate savings to
22 begin.

Line
No.

1 **Q158. What is the Qlik software license investment?**

2 A158. The Qlik investment refers to a financially prudent investment as part of Other Grid
3 Modernization. Specifically, it entailed the acquisition of a three-year license for
4 the Qlik software, as the license was due to expire.
5

6 **Q159. What are the key drivers of the Qlik license investment?**

7 A159. The license, which was set to expire in September 2023, is crucial for the
8 functionality of all applications utilizing OMS data through the enterprise data
9 repository. Failure to renew this license would have resulted in our inability to use
10 this important asset after September 2023. This would have directly impacted field
11 efficiency, in the ability to receive updates from field resources (e.g., Outage Status
12 Application) that is used to status work/crew assignments, add comments, upload
13 pictures, update cause codes and estimated restoration times, etc.
14

15 **Q160. What are the benefits of the Qlik license investment?**

16 A160. This nearly instantaneous data source empowers applications and reports to
17 aggregate and visualize OMS information. These reports and applications are used
18 during outage restoration processes, analyzing hazard events, and proactively
19 notifying field resources when critical events (large outages, hazards, etc.) occur on
20 the system. This, in turn, enhances restoration processes and facilitates quicker
21 outage restoration for customers.
22

23 **Q161. What is the Current Transformer/Voltage Transformer (CT/VT) High**
24 **Voltage Test Console project?**

Line
No.

1 A161. The Current and Voltage Transformer (CT/VT) Test Console is an end-of-life
2 equipment replacement project. This system is used to perform accuracy &
3 dielectric testing on medium voltage transformers.

4

5 **Q162. What is the key driver of the CT/VT High Voltage Test Console project?**

6 A162. The existing system is well beyond end-of-life rendering it virtually non-
7 serviceable and unable to be restored in the event of a failure. This type of system
8 is required to maintain the capability to calibrate and certify these transformers.

9

10 **Q163. What are the benefits of the CT/VT High Voltage Test Console project?**

11 A163. When implemented in 2024, this test system will provide capability to maintain
12 billing accuracy compliance required by the MPSC. Furthermore, the system will
13 enable testing of High Accuracy instrument transformers that the current system
14 cannot support. High Accuracy transformers for metering applications have gained
15 momentum as the manufacturing standard for revenue protection and regulatory
16 compliance. This project removes the risk of losing the capability to perform a
17 required function due to equipment failure.

18

19 **Q164. Why is it important to undertake this project now?**

20 A164. The existing system is not maintainable because many components and servicing
21 options are no longer available.

22

23 **Q165. What are the pre-storm season and post-storm season ADMS Enhancements?**

24 A165. The pre-storm season and post-storm season ADMS enhancements are integral
25 components of a broader ADMS enhancement plan that is discussed later in my

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1 testimony. They were strategically accelerated and scoped collectively, comprising
2 a sequence of targeted upgrades and projects designed to enhance the Company's
3 storm restoration response. These enhancements included direct upgrades to the
4 ADMS applications, as well as upgrades targeting interfaces (e.g., AMI pre-
5 processing), reporting applications (e.g., System Outage Screen), and more.

6
7 These enhancements align with the Company's commitment to storm preparedness
8 and improving the response to severe weather events. The investments made before
9 and after the 2023 storm season focused on improving response times, which
10 includes quicker identification of outages (improvements to outage analysis,
11 processing for momentary outages, event grouping, AMI/SCADA data processing)
12 and faster outage restoration (bulk event updating, bulk crew assignment creation,
13 reducing "okay on arrivals" to improve dispatching efficiency).

14

15 **Q166. What is the key driver of these Pre-Storm and Post-Storm season ADMS**
16 **Enhancements?**

17 A166. The key driver of these ADMS enhancements was to further develop the storm
18 response and communication capabilities of the current ADMS platform to meet
19 changing needs and customer expectations. The series of severe weather events
20 that occurred in parallel with the ADMS hypercare period highlighted that the
21 Company needed to prioritize how outages were predicted, analyzed, and grouped
22 for enhancement. The resulting changes better aligned the technology to show value
23 and included considerable improvements as described later in my testimony.

24

25 **Q167. What is the scope of work completed in 2023?**

Line
No.

1 A167. After go live in February 2023 and working with the new ADMS system through 2
2 storms, including the historic CAT storm, the Company identified program
3 enhancements that would support even greater improvements in storm response.
4 Throughout 2023 there were a series of targeted enhancements made to ADMS to
5 drive improvements in safety, system reliability, usability, and restoration timing.

6

7 The scope of work completed is detailed below:

- 8 • Safety check feature – This enhancement mimics the safety check performed
9 by a field crew before the crew closes an open switch between two circuits.
10 Having this feature allows ADMS users (primarily system supervisors
11 coordinating switching with field crews) to know if that safety check will pass
12 or fail before putting a field crew in a position to have to perform that test.
- 13 • Enhanced outage prediction engine - This improvement to outage event/device
14 prediction increased the prediction accuracy for larger, multi-circuit outages in
15 the higher voltage network (stations, substations, subtransmission, etc.). This
16 enhancement resulted in a reduced number of events that must be managed, and
17 increased precision in communication.
- 18 • Outage analysis processing – These enhancements decreased the time it takes
19 for AMI notifications and customer calls to be analyzed and associated to an
20 event and device location, which reduces the time it takes to create a multiple
21 customer outage event and dispatch a crew.
- 22 • Momentary outages detected by SCADA devices - This improvement in
23 processing prevented sustained outage events from being created when
24 customers have already been restored. This reduces crews from being

Line
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- 1 dispatched to outage events that are already restored and focuses their time on
- 2 sites needing restoration.
- 3 • Event grouping - These enhancements reduce the time needed for dispatchers
- 4 to analyze events before dispatching a crew, reducing overall restoration times.
- 5 • Wiredown grouping - This new functionality enables better insight into
- 6 wiredown occurrences so that the right crews can be dispatched to the correct
- 7 places for quicker restoration, thereby increasing public safety and reducing
- 8 OK on Arrivals (crews sent to locations without active outages). For example,
- 9 this feature enables dispatchers to group geographically located wiredowns to
- 10 send the appropriate number of crews to restore an area rather than looking each
- 11 wiredown as an isolated event.
- 12 • Outage analysis performance - These improvements directly impact how
- 13 quickly customers are associated to an outage event and their capability to
- 14 receive updates for their outages, as well as how quickly their outage can begin
- 15 the restoration process.
- 16 • User interface improvements in new grid framework – These improvements
- 17 allowed ADMS users to filter/group/sort events and crew assignments more
- 18 efficiently. This reduces the time needed to analyze a large volume of
- 19 events/crew assignments in the system and time needed to dispatch the required
- 20 crews for an event.
- 21 • Switch Order Management (SOM) - With the completion of the transition
- 22 period for the first phase of SOM on the ADMS platform, system operators
- 23 within the Company's control room were able to begin using ADMS integrated
- 24 with the work management system (Maximo). This enabled the creation,

Line
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1 management, and completion of certain types of equipment shutdown
2 coordination of the corresponding field work.

3

4 **Q168. What are the benefits of Pre-Storm and Post-Storm ADMS Enhancements?**

5 A168. These enhancements offer many benefits to the Company's customers, crews and
6 overall operations, most notably in the areas of safety, system reliability, usability,
7 and restoration. These enhancements have made the system more versatile and
8 capable of meeting evolving customer needs and have streamlined processes and
9 improved the overall efficiency of the system. By adding advanced features to
10 existing capabilities, the Company has increased safety for customers and crews,
11 built additional system reliability by removing risk for human error, and increased
12 usability to move quicker to get crews dispatched timely and accurately which
13 improves restoration timing while providing customers with more accurate
14 restoration times.

15

16 **ADMS Enhancement**

17 **Q169. What are ADMS Enhancements?**

18 A169. As discussed in the ADMS section of my testimony, although all DMS applications
19 were deployed in February 2023, the Company will continue to build upon this
20 foundation by implementing additional modules and enhancements throughout
21 2023 and beyond. The investments in this category include operationalizing the
22 additional modules of the ADMS to extract the full benefits of the ADMS.
23 Additionally, as stated in the Other Grid Modernization section of testimony, the
24 Company is leveraging the newly implemented ADMS systems breakthrough
25 capabilities to improve storm restoration and customer communication. Initiated

Line
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1 in 2023 after the catastrophic ice storm, these investments were expedited from the
2 overarching ADMS enhancement plan to promptly deliver value to customers. The
3 Company remains committed to sustaining and furthering these investments.

4

5 **Q170. What are the key drivers of the ADMS Enhancements?**

6 A170. The ADMS Enhancements are necessary to ensure that the Company
7 operationalizes all the ADMS applications as planned to realize the full benefits of
8 ADMS. Additionally, ADMS enhancements are necessary to keep up with the
9 evolving needs and challenges of the modern electrical grid, as well as regulatory
10 requirements and enhancements to strengthen cybersecurity measures to protect
11 against potential vulnerabilities.

12

13 **Q171. What is the scope of work planned for ADMS Enhancements in 2024 and**
14 **2025?**

15 A171. The scope of work in 2024 and 2025 is focused on the eMap application, SOM
16 phase 2, SOM phase 3, and added AMI functionality:

17 • eMap application

18 ○ As the Company continues to operate and integrate this new technology,
19 areas of opportunity to further enhance data and refine usage of this system
20 are being exposed. These changes will allow the Company to quickly
21 leverage the full capability of ADMS. The eMap is the intersection and
22 operational interconnection of the as-operated state of the electric grid and
23 advanced engineering data. This combination provides the Company the
24 capability to enable novel applications, such as FLISR, which is an
25 advanced application within DMS discussed later in my testimony.

Line
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- 1 • Switch Order Management (SOM) phase 2
- 2 ○ SOM phase 1 was implemented in 2023 SOM phase 2 includes enabling
- 3 and activating switching and tagging, which directly relates to hazardous
- 4 energy control and is one of the key Safety and effectiveness components
- 5 of the ADMS vision. Phase 2 of the SOM implementation will permit DTEE
- 6 ADMS users to create switching steps and execute orders related to those
- 7 steps within the ADMS platform. Utilizing this capability in the tightly
- 8 integrated ADMS platform means that users may be able to automatically
- 9 model the state of the electric system on the ADMS eMap while performing
- 10 work related to switching and tagging.
- 11 • SOM Phase 3
- 12 ○ SOM phase 3 rounds out the utilization of the SOM application by focusing
- 13 on the tagging aspect of switching and tagging. Fully integrating switching
- 14 and tagging throughout DTE applications means that all switching and
- 15 tagging must be electronic. SOM Phase 3 completes the transformation of
- 16 switching and tagging into a fully electronic process by focusing on a digital
- 17 version of red tag records. Red tag records are the way in which hazardous
- 18 energy controls are documented. DTEE anticipates that this technology
- 19 advancement will lead to additional business integrations and process
- 20 improvements that will benefit the customer through an added layer of
- 21 safety checks and efficiency-related opportunities.
- 22 • AMI Functionality
- 23 ○ To further improve outage prediction and restoration additional AMI
- 24 functionality will be incorporated with ADMS. This includes further
- 25 integration of AMI voltage read data for energization/restoration

Line
No.

1 verification, visualization of voltage data, and aggregation/visibility on
2 multiple customer outage events.

3

4 **Q172. What are the benefits of the ADMS Enhancements?**

5 A172. The eMap plays a crucial role in managing energy operations efficiently and
6 ensuring reliability and stability of the power grid. Enhancements to the eMap are
7 necessary and foundational to unlock advanced functionality in OMS, DMS, and
8 SOM applications. For example, FLISR, an advanced application within DMS, is
9 dependent on the eMap enhancement work in order to be enabled. This work
10 benefits customers through improved restoration efforts.

11

12 **Operational Technology and Error Free Communication (EFC)**

13 **Q173. What is the Operational Technology and EFC investment ?**

14 A173. The Operational Technology (OT) and EFC investment is a collection of related
15 investments that is sub-divided into two complimentary categories: OT investments
16 and EFC investments. The OT investments support the operational activities
17 required to ensure customer commitments, such as restoration times, are met.
18 Whereas the EFC investments are focused on communicating with the customer on
19 those operational efforts. These EFC investments are aimed at resolving
20 communication challenges that lead to customer dissatisfaction.

21

22 The OT and EFC investments have resulted in, and continue to address,
23 opportunities to accurately provide single estimates to customers and deliver
24 effective communications to customers about the status of their restoration. The

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1 investments strategically align at various junctures ensuring a cohesive and fully
2 coordinated set of effective communications for customers.

3

4 **Q174. Is this project also discussed in another Company witness's testimony?**

5 A174. Yes, the project has two separate but related parts. The EFC portion of this project
6 is supported by Company Witness Hatsios. My testimony will describe the OT
7 portion. Table 8 below describes the breakout between OT and EFC.

8

9 **Table 8 OT and EFC Project/Projects by Year (\$000)**

Project	2022	2023	2024	2025
OT	1,254	84	2,400	800
EFC	4,242	52	3,200	600
Total	5,496	136	5,600	1,400

10

11 **Q175. What work was completed in 2022 and 2023 for the OT investments?**

12 A175. In 2022 and 2023 the OT investments were focused on the following projects: Type
13 2 Customer Communication & Processes; Outage Status App Updates and Security
14 Upgrades; and the Pentos PPE Dashboard.

15

16 The Type 2 Customer Communication & Process project implemented three
17 enhancements to improve the Type 2 damage claims process:

- 18 • Introduced new notifications to enhance communication regarding claim
19 status.
- 20 • Implemented functionality to offer comprehensive status categories,
21 involve key stakeholders, and transition Smartsheet functionality into SAP
22 for improved user experience.

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- 1 • Automated the Damage Claims Type 2 process for Electric and Gas
- 2 customers from initiation to resolution. The primary goal is to minimize
- 3 customer communication challenges related to their damage claims that
- 4 often result in MPSC complaints, and to enhance communication and
- 5 resolution timeliness for customers.

6

7 The Outage Status App Updates and Security Upgrades project developed a revised

8 security framework for authorizing access to non-badged contractor crews through

9 the Outage Status app. Prior to this project, contractor crews were required to be

10 badged to have access to the Outage Status app, which is a tool utilized to perform

11 their job duties. Being a badged contractor also allowed the contractor crews access

12 to other Company information. The Company identified the need to restrict certain

13 contract workers to updating the Outage Status app exclusively, therefore removing

14 their access to other Company information. This required a new security

15 configuration to allow non-badged contract crews access to the Outage Status app.

16

17 The Pentos PPE Dashboard project included the development of an employee tile

18 in SAP to centralize and provide access to Personal Protective Equipment (PPE)

19 information for Supply Chain, the Glove Lab, Supervision, and front-line

20 employees. This dashboard was integrated into SAP Success Factors Tile for a

21 unified platform managing all employees' equipment. Additionally, the project also

22 included the implementation of self-service equipment ordering (e.g., PPE, rubber

23 gloves, sleeves, calibration equipment) for both employees and admins.

24

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1 These initiatives collectively contribute to enhancing operational efficiency,
2 communication, and resource management within the OT space.

3

4 **Q176. What is the scope of work in 2024 and 2025 for Operational Technology?**

5 A176. In 2024 and 2025, specific investments are planned in the areas of Data Analytics
6 and Data Engineering, Damage Assessment, DO RCO Enhancement GPS
7 Productivity, and System Outage Screen (SOS) Hardening. As part of this work,
8 investments in technology for Artificial Intelligence (AI) and Machine Learning
9 (ML) will be included to enhance various aspects of operations. Specific examples
10 include optimizing grid management, predictive maintenance, and improving
11 overall system efficiency. These initiatives focus on bringing automation, data
12 analytics, and intelligent decision-making into processes, contributing to increased
13 reliability, cost-effectiveness, and sustainability.

14

15 Data Analytics and Data Engineering for Outage Restoration is a comprehensive
16 initiative that leverages data science to improve the precision of outage restoration
17 time estimates and enhance customer communications. This project involves
18 substantial data engineering and data science efforts to ensure synchronization
19 across various platforms, including outage management systems, AMI, customer
20 services, and communications. The success of this project will be gauged by the
21 accuracy percentage of the first-time estimate time of restoration (ETR)
22 communicated to customers. Importantly, the metrics used to measure success will
23 differentiate between storm and non-storm scenarios, providing a more nuanced
24 understanding of our performance.

25

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1 The Damage Assessment and Inspections Image Analytics project utilizes Artificial
2 Intelligence (AI) and Machine Learning (ML) for image analytics to support the
3 Damage Assessment process. This approach involves training models to identify
4 equipment conditions and assess the extent of damage using images sourced from
5 field personnel, damage assessors, or customers. This technology has the potential
6 to be applied to day-to-day inspections, digitizing processes, and reducing manual
7 work. By adopting image analytics, the utility aims to keep pace with peer utilities,
8 while simultaneously enhancing reliability and improving the customer experience.

9

10 The DO RCO Enhancement GPS Productivity project is focused on upgrading the
11 current GPS dashboard to address issues such as data errors, manual refreshing, and
12 the need for real-time reporting. By leveraging modern technology and cloud-based
13 platforms, the project aims to reduce manual tasks and provide same-day, real-time
14 metrics. These metrics include vehicle time to leave, time to the first job, and time
15 returned to the service center. The goal of the refreshed dashboard is to eliminate
16 gaps in data, offering a comprehensive view of service center time metrics on the
17 same day.

18

19 Within the OT investment is the SOS Hardening project. This project is focused
20 on implementing enhancements to strengthen the resilience of the ADMS System
21 Outage Screen (SOS) and its related capabilities, which includes the ongoing
22 migration of crucial Azure infrastructure that supports SOS reporting and
23 notifications within DTE's Azure environment. In addition, support is being
24 provided for integrating the SOS application with the Outage Status Application
25 (OSA) to enhance the client's Damage Assessment capabilities. The SOS

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1 application provides real-time visibility into customer outages, field crews,
2 schematic diagrams, and other vital information necessary for effective outage
3 management. The primary focus is on ensuring optimal performance, particularly
4 under high-volume conditions during critical storm events. This is to ensure swift
5 responses to customer outages before the upcoming summer storm season.

6

7 **Customer Power Status Visibility Project (CPSV)**

8 **Q177. What is the Customer Power Status Visibility (CPSV) Project?**

9 A177. CPSV represents the first in a series of planned projects whose objective is to begin
10 the transformation of the Company's Advanced Metering Infrastructure (AMI)
11 asset from a purely billing based design to a system capable of maintaining the
12 billing excellence while adding in changes aimed at fully supporting the outage
13 detection and response use case. This use case will materially improve the
14 Company's capabilities related to energization status, outage detection, outage
15 localization, outage response, customer communication and reduction of outage
16 restoration duration.

17

18 **Q178. What were the Key drivers for AMI when originally installed, and does that**
19 **differ from CPSV?**

20 A178. The Company embarked upon its AMI journey in 2009, installing a substantial,
21 real-world pilot to demonstrate the ability to produce and deliver accurate customer
22 bills based upon usage collected remotely, accurately, and efficiently. The AMI
23 pilot and the resulting full-scale implementation of this technology, approved by
24 the Commission in multiple subsequent rate orders between 2009 and 2019,
25 resulted in the Company's ability to consistently gather usage data from ~2.3

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1 million residential electric meters and ~1.3 million residential gas meters. This
2 eliminated the need to send meter readers out to collect that information which has
3 alleviated personal safety concerns while reducing human error. While the
4 Company intends to continue using this technology to maintain the same level of
5 service for customers for this important set of billing benefits, this single primary
6 use case for AMI meters is no longer sufficient to meet the needs of customers,
7 communities, or the Company.

8

9 **Q179. What are the key drivers of the CPSV project?**

10 A179. The primary value driven objective of the Company's CPSV investments is to
11 increase the volume of AMI outage and restoration messages received. The
12 Company uses this information to provide communications to customers about
13 outage occurrences, estimates of repair time, confirmation of outage status and in
14 some cases the detection of nested outages. The Company will also be able to
15 leverage the expanded set of AMI data to reduce cases of outage work remaining
16 open that have been restored.

17

18 Storm events in 2023 highlighted a significant opportunity to improve the way the
19 Company interacts with customers during these most impactful service
20 interruptions. Customers expect that the Company knows before they do that their
21 power has been interrupted, that the Company communicates with them
22 appropriately, and that those communications are timely and accurate.

23

24 Since the February 2023 implementation of ADMS, the Company now possesses
25 an OMS capable of leveraging information about a customer's power status,

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1 surpassing the capabilities of the previous systems. The collection and
2 transportation of this data from the meter to the OMS requires a level of capability
3 and capacity from the AMI system that was not part of the original design
4 specification to which the system was constructed. With the OMS now in place,
5 and having had multiple storm events in 2023 that provided data for analysis, the
6 Company has closely examined the customer communication opportunities and
7 determined an initial set of improvements that are the basis for this project.

8

9 Fundamentally, this project will enhance the existing AMI Network by identifying
10 locations that lack the capacity to transport the volume of data needed from meters
11 to the OMS system and adding additional network communication devices to those
12 locations. These additions will be added in a structured manner based upon the
13 number of customers served, reliability of the electric grid in that area, and
14 reliability of AMI network in that area. Additional considerations, such as the
15 communities served by that network segment, will be taken into account to ensure
16 the Company effectively supports its most vulnerable customers.

17

18 This project will focus on maximizing the:

- 19
- Number of customers that are included in outage communications
 - 20 • Accuracy of the first and subsequent estimate provided to customers
 - 21 • Timeliness of delivering first estimates to customers
 - 22 • Ability to predict customer outages where no direct information is available
 - 23 • Reduction of OK on arrivals

24

25 **Q180. What is the scope of work planned for 2024 and 2025?**

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- 1 A180. The CPSV Project will achieve its objectives through a combination of the
2 following scope items:
- 3 • Replacement of 3000 end-of-life Field Area Routers (FAR) that are no longer
4 performing their intended function in all weather conditions, with up to date
5 and fully functional devices. This replacement will result in more meter alarms
6 and voltage information reaching the AMI system for use by the Outage
7 Management System, Customer system, digital channels, and error free
8 communications infrastructure. These FARs will now have a direct connection
9 to the AMI system reducing the number of communications hops currently in
10 the system to zero.
 - 11 • Installation of 500 additional FAR's to be placed in densely populated areas
12 reducing the number of meters each FAR manages to minimize data loss from
13 oversaturation.
 - 14 • Installation of 22,000 cellular meters placed strategically at premises adjacent
15 to automatically resetting distribution circuit breakers (known as Reclosers) to
16 understand the energization status of that circuit segment without having a
17 SCADA device installed at that location. This will allow system operations to
18 more accurately model and isolate outages.
 - 19 • Deployment of in premise or on meter communications devices in areas where
20 mesh design or other factors make meter communications intermittent as a
21 secondary way of understanding the power status at select premises
22 (prioritization to schools and our most vulnerable customers).
 - 23 • Deploy a suite of monitoring and visualization tools for real time information
24 on all components of the AMI network for operational response.

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- 1 • Design, staff, and deploy a permanent AMI Network Operations Center to
- 2 monitor the AMI communications network with rigor and operational
- 3 awareness at the same level the electric grid that it serves is monitored. This
- 4 staff will include dedicated headcount to perform this monitoring, dispatching
- 5 crews and the field crews themselves, all tasked to keep the AMI network
- 6 operational during all weather conditions.

7

8 **Q181. What are the benefits of the CPSV project?**

9 A181. The CPSV Project will provide the following benefits by the end of the Phase 1
10 period ending in December 2024:

- 11 • Maximize the Number of Customers that are included in outage
- 12 communications. In 2023 the Company included ~60% of customers in
- 13 proactive customer communications. This is driven by the commitment to only
- 14 communicate with customers when there is certainty of up to date and accurate
- 15 information. If that information is uncertain then proactive communications are
- 16 not undertaken. When this project completes its Phase 1 objectives this
- 17 percentage will bring the overall percentage to ~72%, thus adding more than
- 18 250,000 customers that will now have the ability to receive proactive and
- 19 accurate communications from the Company.
- 20 • Maximize the accuracy of the first and all subsequent estimates provided to
- 21 customers. DTEE measures estimate accuracy for all customers that have
- 22 meters that successfully provided a Power Out Notification to the AMI system.
- 23 With the planned network improvements that population will be increased by
- 24 10-15%.

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- 1 • Maximize the timeliness of delivering a first estimate to the customer. With
2 more alarms and voltage information making it to the AMI system the Company
3 will be able to more quickly isolate and assess damage locations and severity
4 improving time to deliver the first estimate by 10% by the end of Phase 1 which
5 will improve on our existing first estimate delivery commitment by between 30
6 and 45 minutes during major storm events.
- 7 • Maximize the ability to predict customer outages where no direct information
8 is available. There are some number of customers that experience an outage
9 and neither the AMI information nor a customer call is available. These
10 customers are identified by predicting their status based on information derived
11 from information from their area and other confirmed outages. More available
12 information reduces the number of outages that must be predicted and increases
13 the accuracy of the OMS outage prediction engine. By the end of 2024, this
14 project will increase the accuracy of these predictions by 10 – 15%.
- 15 • Minimize the number of OK on Arrivals. Due to the nature of a large-scale
16 event like a storm there are restoration jobs where a customers' power is
17 restored and the OMS still has an active job or jobs associated with this
18 customer. Sending a crew to a job that is already restored wastes valuable
19 restoration capacity and prolongs the restoration of real ongoing work efforts
20 as crews report to already resolved outage situations. The Company can locate
21 instances of this condition if it can reliably get the meter status at these locations
22 and use that information to determine if a crew is really needed. At the end of
23 2023, the OK on Arrival percentage for outage jobs during storms was 26%.
24 This project will reduce that percentage by ~25%, bringing the overall rate for
25 OK on Arrivals during storms to ~19% before other additional improvements

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1 to processes are factored in. Using our most recent storm event in 2024 this
2 improvement, had it been executed prior to that event, would have prevented
3 ~250 number of truck rolls saving ~\$250,000 (250 x 1000 calculated cost per
4 crew per assignment) and shortened the overall restoration effort by 4-6 hours
5 to closure.

6

7 **Advanced Metering Infrastructure (AMI) Meter Communications Upgrade**

8 **Q182. What is the AMI Meter Communications Upgrade?**

9 A182. While the CPSV Project represents adding additional capability to the AMI
10 network through redesign and the additional capacity/capability that a denser
11 network device deployment will enable, the AMI Meter Communications Upgrade
12 project represents the capital hardware investment needed yearly to replace end of
13 life devices or those destroyed in the field due to weather events or other incidental
14 damage. There is an ongoing need to procure and install a portion of the fleet of
15 devices each year as part of ongoing pacing of replacement. While included as part
16 of DTEE's strategic projects in the current case, this investment will be covered as
17 routine replacement capital in future rate cases.

18

19 **Q183. What are the key drivers of this program?**

20 A183. Every year there is a portion of the network devices, primarily field area routers,
21 that reach the end of their useful deployed lifecycle or are damaged in place because
22 of weather events or other operational events like third party damage and the build
23 out of new attachments. These devices must be installed and placed into service to
24 ensure that the communications network retains the ability to reliably cover the

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1 service territory. This investment is key to continuing to deliver the value already
2 being derived from the AMI system.

3

4 **Q184. What are the benefits of this program?**

5 A184. This investment allows the Company to continue to deliver accurate billing, offer
6 and manage new rate structures including the Time-of-Day rates, and contributes
7 to the timeliness of outage restoration. Much like other ongoing capital investments
8 in the health of the grid this investment protects performance of these assets
9 throughout the system's deployed lifespan.

10

11 **Q185. What is driving the timing of this investment?**

12 A185. Like any project or program of this type, this spend represents the planned and
13 timely replacement of these devices within this period. That means that there needs
14 to be a yearly investment in these asset replacements. Failure to make this
15 investment will result in an increased likelihood of estimated bills for customers in
16 areas where this equipment fails to operate as expected, potentially extending
17 restoration times during outage events due to less certainty of energization state,
18 and leading to fewer, less accurate communications to customers.

19

20 **Microwave End of Life**

21 **Q186. What is the Microwave End of Life Project?**

22 A186. The Company owns and operates its own set of microwave communications
23 installations. As the network grows, DTEE must replace aging assets as well as add
24 components to strengthen, tune, and optimize the system. This investment includes
25 replacement of microwave paths, enhancements to stabilize the microwave ring,

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1 and support changes mandated by the FCC in deregulation of the 6 gigahertz (Ghz)
2 frequency.

3

4 **Q187. What are the key drivers of the Microwave End of Life Project?**

5 A187. Due to FCC deregulation of privately owned frequencies, DTEE must replace
6 several microwave systems to maintain a reliable network and avoid collisions with
7 other entities using the same frequency.

8

9 **Q188. What are the benefits for the Microwave End of Life Project?**

10 A188. These efforts provide overall improvements to infrastructure redundancy,
11 availability, capability, and security and are being coordinated with the Grid
12 telecommunications program fiber installations to increase resiliency and provide
13 additional network capacity. Upgrading the microwave transport systems serves
14 SCADA reliability, AMI, and provides business intelligence around storm related
15 damages.

16

17 **Q189. What has been accomplished in 2022 and 2023 and what are the scheduled**
18 **plans for 2024 and 2025?**

19 A189. In 2022 and 2023 the Company put into service several new communication
20 support assets targeted at both enhancing existing microwave communication
21 capabilities and securing communications capabilities for the future.

22

23 In support of this in 2022, the Company erected a new tower in Marysville to house
24 new 11Ghz microwave equipment that provides communication between Belle
25 River and Marysville because the existing tower no longer met updated safety

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1 regulations and the new tower supported the installation of a larger number of
2 modern microwave receivers and transmitters. As a result, the Company replaced
3 a leased service link by installing a new microwave path between Hancock
4 substation and the Wixom Pole Yard, reducing overall operational costs.

5
6 In 2023, the Company put into service a Frequency Assurance System that allows
7 management of interference on existing microwaves still in use. The Company is
8 on target to complete 3 more updates to 6Ghz equipment by the end of 2024.

9
10 In 2024 and 2025, the Company will continue to replace both licensed critical paths
11 and unlicensed paths. The implementation of path replacement will improve quality
12 of service, reliability, and allow the Company to release leased telecom services,
13 having replaced them with privately-owned communications, which will reduce
14 operational costs.

15

16 **FLISR Implementation**

17 **Q190. What is Fault Location, Isolation, and Service Restoration (FLISR)?**

18 A190. FLISR is a sophisticated software application that integrates with the other ADMS
19 platform applications, such as Distribution Power Flow (DPF), to enable efficient
20 fault response and power restoration. FLISR combines advanced automation, real-
21 time data analysis, and decision support tools to quickly detect, locate, and isolate
22 faults before restoring power in the event of faults or outages. FLISR is able to
23 function by utilizing information from various sensors, devices, and
24 communications networks. In detail, the components that enable the full
25 functionality of FLISR are as follows:

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- 1 • Distribution Power Flow (DPF): This component is the
- 2 foundational/prerequisite application that calculates the power flows and
- 3 voltages through the eMap network model. This application is required for the
- 4 sequentially-occurring components of FLISR to run. FLISR uses the output of
- 5 DPF to estimate how much fault current would be created if a fault were to
- 6 occur at any point on the eMap. When a fault occurs on the Company's electric
- 7 system, FLISR can combine status indications and analog fault currents to
- 8 estimate where that fault occurred.
- 9 • Fault Location ("FL" in FLISR): Fault locating estimates the location of a fault
- 10 after it occurs on the electric system using fault indicators and fault current
- 11 measurements.
- 12 • Isolation ("I" in FLISR): Isolation is the process in which the fault is
- 13 separated/isolated from the rest of the electric system by using available
- 14 switching devices to create an isolation zone.
- 15 • Service Restoration ("SR" in FLISR): Service restoration is the process in
- 16 which electric service is restored to customers outside of the isolation zone
- 17 without creating loading/voltage violations.

18

19 **Q191. What are the key drivers of FLISR?**

20 A191. This investment provides fundamental support to DTEE's initiative to improve

21 overall outage restoration and storm restoration commitments, and the Company

22 agrees with the Commission's statement in Case No. U-21297 that, "outage

23 restoration is a critical area" (U-21297, pg. 114). The continued investment in

24 FLISR will help the Company improve storm restoration via reduced outage

25 duration, as well as enable the Company to continue realizing the full benefits of

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1 ADMS and automation. Achieving a fully functioning FLISR that operates
2 automatically and safely unlocks an incremental benefit in automating the
3 “isolation” and “service restoration” portion of FLISR.

4
5 The ability to isolate and restore in near real-time is dependent on both FLISR and
6 field equipment that is described in the Distribution Automation section of my
7 testimony. As DTEE system capacity increases and as there is an increase of
8 SCADA penetration, the Company will be able to use FLISR to aid in reconfiguring
9 the electrical system when a fault occurs and reduce outage size and outage duration
10 for customers overall.

11
12 Additionally, the components of FLISR allow the Company to respond to
13 undesirable situations on the electric system in a fundamentally different way. The
14 isolation/service restoration functionality will now allow for the near-real-time use
15 of non-protective devices to isolate faults by creating an isolation zone and restore
16 service to remaining customers by transferring them to adjacent circuits. This is
17 different from how the current system is set up to operate near-real-time and creates
18 more opportunities to impact customer outage size/duration than available currently
19 or that has been historically.

20

21 **Q192. What are the benefits of FLISR?**

22 A192. FLISR offers an array of benefits to DTEE and its customers. Improved fault
23 locating logic will reduce outage duration and decrease strain on devices involved
24 in local logic fault hunting schemes. On-demand isolation and service restoration
25 plans will provide quick and precise ways to reduce the size of outage events in

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1 periods of low and high loading. These beneficial advancements align with other
2 DTEE initiatives to increase SCADA penetration and grid capacity.

3

4 Improved fault locating logic benefits customers experiencing a sustained outage
5 by allowing DTEE to send crews to an estimated fault location instead of needing
6 to perform longer patrols. This becomes especially important in certain areas within
7 the electric system, such as the subtransmission network where crew patrols may
8 take longer due to long distances/overhead line miles that need to be patrolled. This
9 directly impacts the overall customer outage duration by reducing a key part of the
10 restoration timeline (crews patrolling for exact location of damage before repairs
11 can be made and customer's power restored). Getting to the location quicker where
12 repairs need to be made reduces the overall duration of the power outage, directly
13 impacting DTEE's SAIDI.

14

15 On demand isolation and service restoration reduces the size of sustained outages
16 by quickly restoring some of the customers in the initial outage area. The total
17 number of customers interrupted with a sustained outage is reduced when isolation
18 and service restoration occur. Within a short period of time after isolation/service
19 restoration occurs, the customers that are outside of the isolation zone are not
20 impacted with a sustained outage and reduces the overall number of customers
21 affected for the sustained outage event, directly impacting DTEE's SAIFI.

22

23 These combined benefits result in all-weather SAIDI improvements for DTEE's
24 system. The two main benefit drivers are fault location identification and
25 restoration switching analysis. Fault location identification was estimated to have

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1 5-10 minutes of all-weather SAIDI benefit and restoration switching analysis is
2 estimated to have 4-14 minutes of all-weather SAIDI benefit.

3

4 **Q193. Are other benefits expected to be realized?**

5 A193. Using the centralized logic FLISR provides instead of current local fault hunting
6 logic will reduce the stress incurred by devices on the subtransmission system and
7 loop schemes. This can prolong the usable life of such equipment.

8

9 DTEE's loop schemes also face challenges on many circuits caused by limited
10 capacity. There are some situations where the loop scheme is unidirectional. This
11 means that one circuit can host load from an adjacent circuit, but the adjacent circuit
12 cannot host load from the first circuit. There are other situations where a loop
13 scheme is disabled outright during periods of high loading because the loop scheme
14 operation may result in system violations. The centralized logic of FLISR does not
15 require one-way configurations or preemptive disabling. Rather, it uses the real-
16 time state of the electric system as modeled in the eMap, SCADA indications, and
17 forecasted loading to make decisions in the moment of whether service restoration
18 is permissible. The dynamic decision-making process can result in successful
19 service restorations in situations where the local logic may have been defeated.

20

21 Additionally, FLISR can be enabled one feeder/source at a time, as outlined in the
22 implementation plan further down in testimony. DTEE and customers start gaining
23 the benefits for feeders where FLISR is enabled incrementally as it is being
24 implemented over time, and do not have to wait for the full FLISR implementation
25 across the entire system to start gaining benefits from it.

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1 **Q194. What is the implementation plan for FLISR?**

2 A194. The implementation plan for FLISR is a step by step, incremental capability
3 implementation. With this plan, the DTEE grid will see incremental benefits every
4 year, as opposed to an investment where all benefits happen after completion at the
5 end of the project. The initial part of the plan will start with the fault locating
6 functionality within FLISR, then continue to implement isolation/service
7 restoration. As DPF is converging and FLISR turned on for fault locating there is
8 incremental gain. As more devices are added it will incrementally gain some more.
9 FLISR is aligned to a 5-year plan to coincide with the installation of the SCADA
10 enabled field devices that the series of ADMS applications (including FLISR) will
11 automatically control. In the first year of the project, the Company will focus on
12 enabling fault locating where possible in conjunction with developing an
13 implementation schedule that will move each source/circuit from initial fault
14 locating capabilities to the automatic processing for full fault
15 locating/isolation/service restoration via switching to restore customers. This final
16 step will achieve the full benefits of FLISR.

17

18 To achieve the desired outcome for complete FLISR automation, there are three
19 key areas that will be supported to get there.

- 20 • System integration – Integrating FLISR within established infrastructure. The
21 process for managing field devices (both currently installed and future devices) and
22 incorporating them into the system. This includes smart fault indicators, power
23 quality monitoring devices, low-cost monitoring devices, form 6 reclosers,
24 distribution PTDs, micro-processor relays, Viper reclosers, etc.

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- 1 • Grid model tuning with FLISR – Assessing the network model in ADMS to identify
- 2 the regions for tuning, creating the plan for engineers to conduct grid model tuning,
- 3 and reporting to document the process/outcomes, and monitor functionality,
- 4 performance, and any issues/challenge encountered during the process.
- 5 • Distribution Power Flow (DPF) convergence support – Iterative testing and
- 6 tuning/configuration to ensure convergence and high-quality results (e.g., precision
- 7 of topology and power flow results)

8

9 **Distributed Energy Resources Management System (DERMS)**

10 **Q195. What is the DERMS?**

11 A195. The electric grid in the future will need to incorporate new technologies, including

12 Distributed Energy Resources (DER) such as solar and battery storage. To enable

13 and support the grid benefits of these resources as well as manage the complexities

14 of intermittent and two-way power flow, utilities must plan for DER integration.

15 DERMS is a control system specifically designed to handle DERs at the residential,

16 commercial, and industrial, and distribution grid levels. A DERMS acts as a

17 switchboard for DER-related protocols and information to simplify the

18 management of these disparate systems and feed information into other utility

19 backend systems for planning, operations, and customer engagement. In addition

20 to solar and storage, these DERs can include demand response, electric vehicles, or

21 other distributed technologies.

22

23 **Q196. What functionality is present in a DERMS?**

24 A196. A Utility DERMS is composed of multiple key functionalities:

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- 1 • Track the location, status, configuration, and capabilities of all DER on the
- 2 electrical system.
- 3 • Track the energy management and economic program assignments, criteria and
- 4 constraints for each DER and identify and prevent conflicts.
- 5 • Provide interfaces to all of the DER related protocols, controls, both utility
- 6 controlled, and vendor controlled, and interfaces to utility information systems
- 7 such as Customer Relationship Management (CRM), Billing, Market Systems
- 8 and the ADMS.
- 9 • Provide the capability to capture data, availability, and performance from the
- 10 DER, either directly or from third parties and to send dispatch commands to
- 11 those devices.
- 12 • Forecast the real time and short-term availability, energy balances, and
- 13 capabilities of registered DER, this includes Demand Management and
- 14 Response which coordinates solar, storage and flexible loads to regulate peak
- 15 demand, execute energy efficiency, and align with utility and market programs.
- 16 • Optimize those dispatch commands both for energy savings and economics, all
- 17 while maintaining and respecting program constraints, customer decisions and
- 18 grid constraints and maintaining the operability of the electrical system.
- 19 • Management functions of the DERMS are to aggregate DERs into groups that
- 20 can be more easily coordinated, controlled, and dispatched, and automate the
- 21 dispatch and optimization functions with algorithms to support Transmission
- 22 and Distribution System coordination while balancing Market and real time
- 23 operational constraints.

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1 Because of this broad scope, a DERMS system must have interfaces to nearly all
2 utility systems, most importantly the ADMS, market and the customer information
3 systems.

4

5 **Q197. What is the benefit of a DERMS?**

6 A197. The DERMS provides a central location to consolidate interfaces to different DER
7 types and vendor systems and present it consistently to the ADMS. Without this
8 consolidation each different type of DER or vendor system would need a custom
9 integration to the ADMS and changes to vendor interfaces would impact ADMS
10 operations, making each integration more costly and time consuming. The DERMS
11 also provides optimization of dispatch of DER, allowing the system operator, or
12 market signal, to set a dispatch goal in the ADMS for a specific area of the system.
13 The DERMS evaluates the available and registered resources to accomplish the
14 goal, balancing DER constraints and customer impacts with the timing and duration
15 of the dispatch.

16

17 **Q198. What is the optimal timing to begin DERMs implementation?**

18 A198. DTE will begin investment in DERMs in 2025. This will allow a clear evaluation
19 of MISO FERC 2222 requirements that will be available by Q3 2024.
20 Electrification and DER adoption will only increase over time, and more complex
21 DER hardware is being made available to customers available to customers
22 continuously. To meet customer needs and provide necessary operational
23 coordination it is imperative to have a working system in place to support these
24 capabilities. The complex implementation of a DERMS must begin now to allow
25 adequate time for the number of interface and system changes required, and to

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1 procure the necessary functions for compliance. In addition to preparation for future
2 needs, immediate benefit from a DERMS can be realized through integration of
3 many existing programs, producing streamlined coordination with the control
4 room, and generating benefit from initial investments including demand response
5 and load control programs.

6

7 **Q199. What is DTE's strategy for deploying a DERMS cost effectively?**

8 A199. The Company's strategy is to focus on the areas where DERMS is needed for
9 compliance and areas where it can increase the efficiency of existing processes and
10 systems and build interfaces or consolidate systems that currently do not work
11 together. This approach is a System of Systems, where components are
12 implemented as they are needed and at the scale that they are needed. Some of the
13 first components that are needed are consolidation of management systems that
14 coordinate DER and DR data and program participation and interfaces to the
15 ADMS. This will allow current DR and DER programs to be tracked more
16 efficiently, benefitting customers that are currently in DR, load management and
17 DER programs and enabling the dispatch of larger existing SCADA controlled
18 assets in coordination with the ADMS and Market Systems to support currently
19 implemented programs such as FERC841. Future phases will focus on the
20 forecasting and optimization as well as automation of constraint management and
21 Distribution System Operator (DSO)/ Transmission System Operator (TSO)
22 coordination.

23

24 **Q200. What is the scope of the investment in DERMS in 2025?**

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1 A200. The initial investment will be in the program and configuration database to
2 centralize program management, program constraints and the tools to assign DER
3 to system model nodes. This will be done in parallel with ADMS enhancements to
4 be able to control dispatch of identified resources and enforce constraints at circuit
5 level granularity. These first interfaces will utilize existing programs including
6 Commercial Interruptible customers, Demand Response, Interruptible heating and
7 air conditioning and Load Management System functionalities and other DER
8 programs. DTEE has identified a key list of requirements for framework,
9 functionality, demand response, and integration into utility systems and is currently
10 evaluating vendors to identify the partner best able to satisfy all needs.

11

12 **Q201. Will this approach be able to scale to support the state's clean energy**
13 **transformation?**

14 A201. Yes, this approach allows for capacity to expand while adoption rates of DER are
15 growing. Approaching the complicated problem of a DERMS by addressing
16 fundamental systems and data and investing in and implementing components as
17 they are needed and at the scale they are needed, the DERMS implementation will
18 be able to benefit existing customers participating in DR and DER programs today
19 and expand as FERC 2222 and other future programs are brought online. As DER
20 integration grows, the speed of adoption is still uncertain, and it is not practical or
21 cost effective to implement a system that can initially provide the capability to
22 support millions of customer DER that may not materialize. However not having a
23 system to manage DER in a comprehensive way would lead to potential non-
24 compliance, inefficiencies, and degraded customer experience.

25

Line
No.

1 **Substation Cybersecurity Program**

2 **Q202. What is the Substation Cybersecurity Program?**

3 A202. As technology and automation investment grows, the number of devices deployed
4 on the grid will also grow, driving a need for increased cybersecurity to protect the
5 devices and grid controls. The Substation Cybersecurity program will develop and
6 deploy cybersecurity tools supporting the increasing use of distribution automation
7 devices across DTEE substations and circuits. This program aligns with the NIST
8 Cybersecurity Framework (National Institute of Standards and Technology),
9 Cybersecurity program management and architecture requires situational
10 awareness, threat and vulnerability management, asset and configuration
11 management, and incident response among other activities.

12

13 **Q203. What is the scope and benefits of the Cybersecurity Tools program?**

14 A203. This project made improvements to the physical security at Stone Pool substation
15 in 2023 as well as procurement and testing of software for situational awareness,
16 threat and vulnerability management inside the substation, and asset and
17 configuration management. In 2024, penetration testing, and further integration of
18 physical and cyber alerts will be completed to close out the Stone Pool Substation
19 portion of the project. This work will ensure robust protection at Stone Pool as well
20 as inform standards, policies and procedures to ensure cybersecurity at future
21 substations and inform optimal mitigations at other existing substation in the future.
22 Work in 2024 and 2025 also includes the procurement of distribution device
23 compatible cyber security hardware that can be used to secure devices that are
24 deployed on distribution circuits and the collection of industry data and best
25 practices for cybersecurity for circuit level distribution assets including an

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1 independent threat and vulnerability assessment of these approaches. This work
2 will inform future process and program developments to ensure increased
3 monitoring and control of the distribution system is paired with the necessary
4 increases in cybersecurity.

5

6 **Automation Configuration Database**

7 **Q204. What is the Automation Configuration Database Project?**

8 A204. The Automation and Configuration Database is an investment in tools for improved
9 tracking of intelligent electronic devices, specifically distribution relay and network
10 communications equipment. As distribution automation equipment becomes ever
11 more sophisticated it is important to ensure more detailed information about devices
12 is retained and leveraged. Traditional relay database may only capture items like
13 device type and settings, as devices become more sophisticated it becomes
14 important to track additional information such as device configurations, software
15 version, and firmware status. It is also important that this data be stored in a readily
16 accessible way to allow for connection with other data systems, effective patch
17 management, and cybersecurity monitoring. This project will replace the existing
18 in house database with an industry standard tool, improving data accessibility and
19 ability to coordinate asset, work management, and protection data between
20 databases increasing work efficiency and supporting increases in automation
21 resulting in faster design of projects for customers, reductions in commissioning
22 and maintenance duration where equipment is out of service and minimize the
23 chance of devices being misconfigured or having out of date settings that could
24 adversely impact customer reliability.

25

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1 **Q205. What is the scope of work on the Automation and Configuration database for**
2 **2024 and 2025?**

3 A205. The 2024 scope will include the software evaluation and selection as well as
4 verification of compatibility of relay test equipment with software selection. 2025
5 scope will include data cleansing and implementation of the database as well as
6 establishment of connection between relay test equipment and automation and test
7 record database.

8

9 **H. Distribution Planning**

10 **Q206. What is the Distribution Planning investment category?**

11 A206. The dynamic nature of the grid requires that engineers regularly analyze grid
12 capabilities including capacity, reliability, and adequate voltage support, to support
13 integration of new load and other new customer needs such as DER. Distribution
14 Planning is a category of investments in the tools, processes, software applications
15 and data models supporting the near and long term planning of the distribution
16 system. It includes the applications to correlate and consolidate changes to the
17 electrical system model so that the different planning tools and the ADMS can
18 utilize the same data set to perform the necessary analysis for power flow, power
19 quality, contingency analysis and project scenarios. These tools assess the impact
20 of bulk power system modifications, customer requested interconnection and
21 loading changes, and utility initiated upgrades to the electrical system. This
22 category also includes the tools to assess the civil, mechanical and structural aspects
23 of project engineering and design. In concert, these tools and systems allow the
24 Company to optimize projects and consider alternatives in a quantitative and
25 physics-based manner.

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1 **Q207. Where are the capital investment details of the projects and programs in this**
2 **category?**

3 A207. Capital investment details of these projects and programs in this category are
4 included in:

- 5 • Exhibit A-12, Schedule B5.4, page 17-18
- 6 • Exhibit A-23, Schedule M7

7

8 **Table 9 Distribution Planning Investments Exhibit Locations**

Program/Project	Exhibit A-12 Sch. B5.4	Exhibit A-23 Schedule M7	Exhibit A-23 Schedule M8
ADMS: Network Management System	p. 18, line 41	pp. 12-16	pp. 150-155
Load Forecasting & Analytics	p. 18, line 42	pp. 92-95	pp. 150-155, 244
Interconnection Process Enablement	p. 17, line 29	pp. 87-91	pp. 150-155, 246-249
Hosting Capacity Enablement	p. 18, line 43	pp. 83-86	pp. 150-155, 250-251
Power Quality Analysis Program	p. 18, line 44	pp. 169-172	pp. 150-155, 251-252
Substation Design Tool Upgrade	p. 18, line 45	pp. 197-202	pp. 150-155, 252
Distribution Planning	p. 18, line 46	pp. 50-53	pp. 150-155
SCADA Remote Access and Configuration Platform	p. 17, line 19	pp. 177-180	pp. 150-155, 243

9

10 **Q208. Why is investing in technology for Distribution Planning essential for DTEE**
11 **and customers?**

12 A208. These investments incorporate enhancements to existing tools, new tools, and
13 interfaces to allow more frequent and accurate modeling of the distribution system
14 and analysis of planned changes. A number of different tools are used by

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1 engineering and design during the development of a project and during annual
2 system studies. The investments in these different tools keep them up to date, add
3 enhancements and capabilities and improve the efficiency of the design process.
4 Distribution planning encompasses tools needed for distribution planning, design,
5 specification, modeling, forecasting and the analytics of associated data. This area
6 accounts for systems and engineering tools needed to perform modelling functions
7 accurately and effectively for all distribution planning activities and investments.
8 These individual tools are also used by planning engineers in modeling grid impacts
9 and the calculations needed to implement projects to design standards. These
10 investments support streamlining the customer interconnections process and
11 include investments in hosting capacity mapping.

12

13 **Network Management System (NMS)**

14 **Q209. What is Network Management System (NMS)?**

15 A209. As part of the ADMS project, the Company implemented a Network Management
16 System (NMS) in 2020. NMS incorporates network data from the Geographic
17 Information System (GIS) and combines the network data with other systems to
18 directly serve the new ADMS functionality. NMS consolidated multiple network
19 models to one common network model, resulting in a consistent view of the
20 electrical system in real time to be used by all functions of the ADMS. Moving
21 from multiple networks models into one had many advantages, it promotes data
22 consistency, simplifies maintenance, improves integration capabilities, and leads to
23 operational efficiency. This data model is also used by the distribution planning
24 tools to provide the base model information for all planning studies.

25

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1 **Q210. How was the NMS program structured and implemented?**

2 A210. The NMS program was broken up into multiple phases to align with the short-term
3 and long-term data requirements for ADMS and other projects. The initial phase of
4 NMS included implementing operational dashboards for monitoring data quality,
5 employing machine learning models to correct data issues, and consolidating
6 multiple sources into a single location (GIS) for use in external systems. In 2020,
7 following the successful completion of the initial phase and setting the foundation
8 for maintaining high-quality systems for data, the Company adhered to its plan by
9 advancing the NMS investment. Additional initiatives were implemented to
10 improve and add more information into our network model, enabling future
11 technology investments and existing technology enhancements to maintain a high
12 level of accuracy.

13

14 The NMS investments, which are described in detail later in my testimony, are
15 targeted to four areas of focus:

16

17 **1. Common Platform:** Moving to a shared technology foundation that facilitates
18 seamless interaction and collaboration between different systems, applications, and
19 devices. This allows for data to be extracted from the source and eliminates
20 potential for human error. For example, distribution circuit operating maps will be
21 directly generated from the GIS, ensuring more accurate data for field and system
22 operations. This avoids the work delays that field workers currently encounter
23 when manually reconciling map differences, allowing restoration work to happen
24 faster.

25

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1 **2. Network Model Enhancements:** Involves improving and expanding the
2 representation within the network model. It includes adding new data fields,
3 refining existing ones, and incorporating more accurate and detailed information to
4 capture the characteristics of the network. The goal is to enhance the model's
5 accuracy, completeness, and usability for applications that use the data.

6

7 **3. Grid Model Analytics:** Centers on using analytics to gain insight into behavior,
8 performance, and characteristics of the grid. The objective is to improve reliability,
9 efficiency, and overall functionality of the electrical grid by leveraging data-driven
10 insights derived from the grid model.

11

12 **4. Asset Data Integration:** Consolidates data from different databases, sensors,
13 and sources to create a unified and comprehensive view of the assets. The goal is
14 to enhance data accuracy, accessibility, and usability, enabling better decision-
15 making and management in a coordinated manner.

16

17 **Q211. Has the MPSC supported past investments in NMS?**

18 A211. Yes. On Page 116 of the December 1, 2023 Order in Case No. U-21297 the MPSC
19 stated that "The Commission agrees with DTE Electric that "[g]rid needs are
20 dynamic, and the tools to support reliability and grid modernization also need to
21 adapt and develop to support these emerging grid needs." 5 Tr 2945." and the
22 amount requested by the Company was approved.

23

24 **Q212. Will continued investment be needed for NMS?**

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No.

1 A212. Yes. As the electric grid continues to change, the systems that support the
2 management of the electric grid will also need to be updated and change. Sustained
3 investment provides critical source data for operational systems (e.g., ADMS –
4 DMS network model application), and is the basis for an accurate interpretation of
5 the current status of the electrical system. This is essential for the safe and effective
6 monitoring and operation of the electrical grid. Specifically, these initiatives will
7 improve the Company’s capability to analyze electrical load distribution, identify
8 overloaded areas in the network, and plan upgrades more effectively. This approach
9 enables the Company to accurately model and analyze growing electrical demand
10 and improve service quality and reliability for customers.

11

12 **Q213. Since the initial NMS Implementation, what has been accomplished to date?**

13 A213. To date, there have been prudent investments made in the four areas of focus:

- 14 • **Common Platform:** 328 operational maps have been converted.
- 15 • **Network Model Enhancements:** 30 new data fields have been added to the
16 network model.
- 17 • **Grid Model Analytics:** Data quality for dynamic protective devices and
18 capacitors improved by 18% in 2022, and data quality for switches, fuses, and
19 regulators has improved by 30% in 2023.
- 20 • **Asset Data Integration:** 8 asset types were synchronized between GIS and
21 Maximo and new data governance was established with clear data ownership
22 accountabilities and support processes. In 2023, the AC network meter
23 connectivity pilot was brought to completion and the NMS started supporting
24 Distribution Power Flow (DPF) application in enhancing the network data
25 models.

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No.

1 **Q214. What are the plans for NMS in 2024 and beyond?**

2 A214. The focus for 2024 is on supporting and strengthening DPF and FLISR applications
3 by developing new network models and augmenting existing network models with
4 the addition of 10 new data fields . The objective for grid model analytics is to
5 improve the data quality for primary and sub-transmission OH and UG lines by
6 10%. In addition, the Company will invest in AC network connectivity and asset
7 data integrations by synchronizing 4 asset types between GIS and Maximo. Future
8 plans are to continue to support DPF and FLISR applications and continue
9 implementation of AC network connectivity. For network model enhancements, the
10 goal is to add 5 new data fields to the network model and improve and develop new
11 algorithms to enhance phasing and meter to transformer connectivity. In grid model
12 analytics, the target is the improvement of data quality for smart fault indicators
13 and DERs by 10%. These continued investments contribute to the Company's
14 capability to identify areas with high demand or vulnerabilities in the grid. Using
15 this data to improve our planning processes results in higher quality customer
16 service improvements.

17

18 **Q215. What are the benefits of the investments in the Network Model for the**
19 **Company's customers?**

20 A215. High-quality data is the backbone of the ADMS system, and ADMS is central to
21 day-to-day and storm grid management. Investing in data quality improvements is
22 foundational to enabling all the potential value in the remaining ADMS
23 components.

24 As an alternative to NMS enhancements, manually performing the functionality
25 provided by network model investments would require an estimated 20 additional

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1 Full Time Employees (FTEs) to manually maintain data between systems (for
2 example, synchronizing the location of the assets, operating voltage ratings, etc.,
3 across the systems). Highlighted in Case No. U-21297 by Witness Reterstorf (5T
4 2911-2912), the Company referenced an avoidance of 20 O&M personnel due to
5 continued investments in NMS (at the time of filing U-21297, the cost of adding 7
6 of these 20 personnel was avoided). At the time of filing, DTEE estimates that the
7 cost of adding 14 of these 20 O&M personnel has been avoided as a result of these
8 Network Model investments. DTEE is on track to achieve the 20-FTE target by the
9 end of 2024.

10

11 **Q216. Can you describe the realized and projected operational benefits of the**
12 **additional investment in the four focus areas of NMS?**

13 A216. Investments to date have improved the Company's operational ability to generate
14 maps from GIS, improved load analysis ability, and enabled more accurate
15 preventative maintenance planning. Combined with the remaining work in 2023,
16 this investment will continue to improve the data quality as outlined below.

17

18 **1. Common Platform:** The transition to a single platform will provide more
19 accurate Network Model data for field operations by directly generating operating
20 maps from the GIS and eliminating the CAD tool.

21

22

23 **2. Network Model Enhancements:** These enhancements will improve
24 downstream processes—including distribution planning, grid operations, and
25 customer interconnections—resulting in more accurate data models. The new data

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1 fields added to the model each year across the system to further understand and
2 quantify the effects of these types to the network model.

3
4

5 **3. Grid Model Analytics:** These machine learning models will be run periodically
6 to identify and correct data within the base Network Model. Improvements in data
7 accuracy and availability address attributes such as KVA, operating voltage, and
8 phasing.

9

10 **4. Asset Data Integrations:** Synchronizing the data in the GIS platform with the
11 data in the work management platform (Maximo) will provide accurate asset data
12 to improve preventative maintenance schedules, ultimately improving system
13 reliability.

14

15 **Load Forecasting & Analytics**

16 **Q217. What is Load Forecasting and Analytics?**

17 A217. Load Forecasting and Analytics is a program that represents investments in
18 planning tool capabilities that are focused on the essential industry standard
19 distribution planning tool CYME that models distribution circuits and calculates
20 load flow, and the load analysis tool Power Runner which combines SCADA, AMI
21 and forecasted load data to generate load allocation scenarios to CYME. This
22 category of investments include required software licensing, associated server
23 hardware, interfaces, and functionality enhancements for this software and
24 supporting planning tools.

25

Line
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1 **Q218. Did the commission order in Case No. U-21297 express any concerns about**
2 **these investments?**

3 A218. Yes, the order indicated that additional evidence to support the investment was
4 needed, and also raised a question about accounting related to the amount of labor
5 when compared to materials. The following testimony details the program and
6 investments to provide additional evidence.

7

8 **Q219. What investments were made in 2022 and 2023 and what are the benefits to**
9 **customers?**

10 A219. Investments in 2022 and 2023 included the upgrade of the CYME distribution
11 planning tools and required licensing and server hardware to the latest supported
12 version which will enable improved modeling for hosting capacity and non-wire
13 alternatives and allow for new modules that will be implemented in 2024 and
14 beyond. Investments also included the initial deployment of Power Runner
15 licensing, servers and software that combines SCADA, AMI and forecasted load
16 data from every meter on the system, to produce hourly load allocation curves. For
17 subtransmission tools, TSAT software and required license was purchased as it is
18 now a requirement for MISO Dynamic model studies.

19

20 **Q220. What investments are planned in 2024 and 2025 and what are the benefits to**
21 **customers?**

22 A220. 2024 investments include enhancing CYME to load data from Power Runner to
23 allow for multi time period scenario analysis and the implementation of CYME
24 Advanced Project Manager which allows sequencing of system model changes to
25 project plans and linkage to Maximo workorders. Enhancements will also be made

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1 to allow for substation models to be loaded into CYME to improve the analysis of
2 circuit load transfers, conversion, and consolidation. The combination of Dynamic
3 Data Pull (DDP) module for load allocation and Advanced Project Manager (APM)
4 module allows projects to be studied in multiple phases and validate that schedule
5 changes to project do not violate constraints. This will also improve interconnection
6 studies as the in-service date of projects can now be considered for coincident
7 projects to determine interactions. 2025 enhancements to CYME will begin the
8 implementation of the Advanced Distribution Planning System which is a
9 collection of CYME enhancements that are being implemented at other utilities that
10 address DER and NWA scenario planning and automate many common tasks and
11 reports that are run by engineers. Power Runner will be enhanced to provide more
12 validation of load profiles and be integrated with as-operated status of the system
13 to better model load transfers and switching. Power Runner will also incorporate
14 the sub transmission model hierarchy to allow for preparation of sub transmission
15 loading data sets into tools like PSSE. PSSE enhancements will be made in 2024 to
16 comply with MISO MOD32 data modelling requirements and to perform new gross
17 load calculations at model nodes. The SEEQ analytic tool will also be enhanced,
18 this provides detailed data analysis capabilities to time series signals and allows for
19 complex calculations for asset health and other engineering calculations. 2025
20 investments will begin to improve forecasting and propensity analysis of DER
21 adoptions. These enhancements will lead to more accurate system studies, more
22 efficient interconnection screens and studies and better optimized designs for
23 system improvement, non-wire alternative and loading projects. Customers will
24 benefit from reduced interconnection study and review times and more accurate up
25 front estimates of system upgrades.

Line
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1 **Interconnection Process Enablement**

2 **Q221. What is interconnection process enablement?**

3 A221. Interconnection process enablement are investments focused on the software and
4 interfaces for interconnection processing that includes both the interconnection
5 portal and the interconnection database, PowerClerk. Additional investments are
6 made in tools and interfaces to streamline interconnection processing, study and
7 screening and benefit customers by improving the application, screening and study
8 response times and accuracy. These investments are driven by changes to market
9 programs, interconnection rules, procedures, and tariffs. These enhancements also
10 streamline the process and improve the customer experience when applying for and
11 connecting DER.

12

13 **Q222. What investments were made in 2022 and 2023 and what are the benefits to**
14 **customers?**

15 A222. In 2022, the major investments implemented online payment processing for
16 interconnection fees and enabled single login for customers, which allows them to
17 access the interconnection portal with the same username and password as their
18 DTEE online account. 2023 investments included improvements to PowerClerk
19 forms, automation, website pages and documentation to support the new
20 interconnection rules initiated in case U-20890 and implemented changes to fee
21 structures and online payment as part of the new rules.

22

23 Some investments in this category are related to field gateway hardware as
24 discussed in the Grid Edge Enablement section of this testimony. After 2023, the

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1 field gateway hardware investments will be split from this category to align the
2 program with the OT investments.

3

4 **Q223. What investments are planned in 2024 and 2025 and what are the benefits to**
5 **customers?**

6 A223. Investments for 2024 include completing the payment portal changes to support the
7 new interconnection rules and security enhancements to a single sign on login. 2024
8 investments include the renewal and refresh of the PowerClerk system.
9 Enhancements in 2024 will increase automation associated to the interconnection
10 process for small interconnections. Additionally, the enhancements include
11 backend improvements to screening and study that will increase application
12 throughput and reduce manual labor in preparing and running studies. Further
13 updates and automation improvements will be done in 2025 to comply with
14 interconnection procedures changes. The 2025 investments also aim to streamline
15 the screening and study process and initiate the implementation of FERC 2222
16 related application and screening processes into PowerClerk.

17

18 **Hosting Capacity Enablement**

19 **Q224. What are the investments in Hosting Capacity Enablement?**

20 A224. Hosting Capacity Enablement includes improvements to the online publicly
21 available map system that displays hosting capacity, and the capabilities to compute
22 hosting capacity and process the data for it to be available publicly.

23

24 **Q225. What investments were made in 2022 and 2023 and what are the benefits to**
25 **customers?**

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1 A225. Investments in 2022 and 2023 included publishing the initial hosting capacity map
2 for DER and improving backend data handling to prepare updates. In 2023, the
3 focus was on developing the loading capacity map. These maps allow customers to
4 see the amount of remaining capacity and hosting capacity in their area.

5

6 **Q226. What investments are planned in 2024 and 2025 and what are the benefits to**
7 **customers?**

8 A226. Investments in hosting capacity for 2024 are aimed at enhancing the backend data
9 update mechanisms of the system. In 2025, the focus will shift towards integrating
10 the analysis capabilities, which are being developed in the load forecasting and
11 analytics project, into the outputs of the hosting and load capacity maps. This
12 integration will result in a more detailed representation of hosting capacity values
13 across numerous circuit sections. The increased granularity of data will provide
14 customers with additional information, aiding their decision-making process.

15

16 **Power Quality Analysis Program**

17 **Q227. What is the Power Quality Analysis program?**

18 A227. The Power Quality Analysis program are investments in software to centralize,
19 collect, correlate, and visualize power quality data such as fault and disturbance
20 waveforms, voltage disturbances, harmonics, flicker and momentary information
21 from various metering sources on the system and provide analysis capabilities to
22 help determine root cause of events and begin to establish predictive capabilities
23 from analysis of disturbances that have not yet created an outage or equipment
24 issue.

25

Line
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1 **Q228. What investments were made in 2022 and 2023?**

2 A228. None, this is a new investment category in 2024.

3

4 **Q229. What investments are planned in 2024 and 2025 and what are the benefits to**
5 **customers?**

6 A229. Investments in 2024 will be to centralize power quality information into a single
7 data set that can be analyzed and correlated with complaints, trouble events and
8 outages. Interfaces for near real time capture of power quality meter data will be
9 established. In 2025 analysis tools and machine learning capabilities will be added
10 to the system to determine root cause and begin the process of identifying
11 precursors to predict failures and outages from sensor and power quality data.

12

13 **Substation Design Tool Upgrades**

14 **Q230. What are the investments in substation design tools?**

15 A230. This category of investments is comprised of design and structural calculation tools
16 that are used by engineers, planners, and designers to implement standards and
17 calculated physical analysis into designs prior to construction. This includes new
18 tools to facilitate rapid compliance for pole and overhead structure calculations and
19 steel work as well as enhancement to CAD design tools to improve integration into
20 work management, scheduling and cost estimating.

21

22 **Q231. What investments were made in 2022 and 2023 and what are the benefits to**
23 **customers?**

24 A231. Investments in 2022 and 2023 included renewal of PLSCAD, a sophisticated
25 structural design software for engineered poles and purchase of documentation

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1 editing and collaboration software for CAD designs. Other investments began the
2 process of implementing compatible units for substation standards and structural
3 design testing.

4

5 **Q232. What investments are planned in 2024 and 2025 and what are the benefits to**
6 **customers?**

7 A232. 2024 investments include renewal and enhancements of the Spidacalc pole design
8 software and to acquire specialized structural modelling tools to allow for
9 engineered structure designs to be verified. Additional structural design testing will
10 be done in 2024 to validate the modelled parameters in the software and update
11 design standards accordingly. 2025 will begin the process of updating the
12 substation design tools and interfaces to utilize the compatible units and closely
13 link design to the Maximo and supply chain process.

14

15 **Distribution Planning**

16 **Q233. What is Distribution Planning (Exhibit A-12 Schedule B5.4, Page 18, line 46)?**

17 A233. Distribution Planning is a collection of projects within the Distribution Planning
18 OT category and represents a set of investments from the other sub programs in the
19 Distribution Planning OT category.

20

21 **Q234. What investments were made in 2022 and 2023 and what are the benefits to**
22 **customers?**

23 A234. The breakdown of significant investments are as follows:

- 24 • \$98,000 of this investment to load allocation and analytics for a tool to evaluate
25 transformer overloads and root causes, as well as a tool to understand EV

Line
No.

1 adoption and how it is impacting circuit and transformer loading. This tool
2 allows the Company to more accurately pinpoint where infrastructure needs to
3 be updated due to DER.

4 • \$603,000 to the load allocation and analytics project for the CYME 9.2 upgrade.
5 This includes the license renewal and server hardware for that project. The
6 benefits of those investments are covered in the Load allocation and analytics
7 and Cyme Upgrade sections earlier in the testimony.

8 • \$64,000 to the substation and structural tools budget for Bluebeam CAD
9 markup tool for license renewals. Bluebeam CAD significantly streamlines
10 field print markup for substation designs and reduces planning and design time.

11 • This line item also includes investments made to systems that support the
12 Company's ADMS system to bring additional operational data to our
13 employees when responding to unplanned field events resulting in better overall
14 control and effectiveness (\$8.46 million).

15

16 **Q235. What investments are planned in 2024 and 2025 and what are the benefits to**
17 **customers?**

18 A235. This category will invest in small emergent needs for planning tools in 2024 and
19 2025 that do not clearly align to the other sub projects. Projects are selected from
20 an existing backlog list for each investment year. These investments will either
21 evolve into their own sub projects in the future or be incorporated into existing sub
22 projects. Larger investments that can be clearly aligned with existing OT sub
23 programs will be charged appropriately to eliminate the historical mixing of
24 investment categories in this project going forward. A major investment planned
25 for this category in 2024 and 2025 is the Circuit Reliability Optimization project.

Line
No.

1 The scope of this system is to provide a digital platform to examine and monitor
2 every circuit for emergent events, reliability initiatives, maintenance tasks, and
3 enhancements. It will also assess the influence of reliability programs, maintenance
4 activities, and upgrades on the improvement of each circuit's reliability and evaluate
5 the most effective reliability enhancement strategies, including ETTP, PTMM,
6 Hardening, and Conversion. The system will also quantify the impact of various
7 programs on the reliability of circuits, substations, sub-transmission, and the
8 contribution to the overall system.

9

10 **I. Work Management and Scheduling**

11 **Q236. What is Work Management and Scheduling?**

12 A236. Work Management is a systematic approach to track and measure work as well as
13 streamline both business processes and routine tasks. This category of investments
14 describes the essential set of work management tools and technologies that are used
15 to coordinate work on the distribution system, from initiation through close out of
16 work orders, including the work steps, assignment of labor, materials, and other
17 tasks. While current schedules and processes rely on Microsoft Excel, the benefits
18 of automation, like drag-and-drop schedules, real-time field status updates, and
19 integration with systems such as OMS and Maximo, are realized through these
20 investments. Job planning, along with managing labor, material, tools, and services,
21 is also part of the suite of tools for effective work management.

22

23 **Q237. Where are the capital investment details of the projects and programs in this**
24 **category?**

Line
No.

1 A237. Capital investment details of these projects and programs in this category are
2 included in:

- 3 • Exhibit A-12, Schedule B5.4, page 17 and 18
- 4 • Exhibit A-23, Schedule M7

5

6 **Table 10 Work Management and Scheduling Exhibit Locations**

Program/Project	Exhibit A-12 Sch. B5.4	Exhibit A-23 Schedule M7	Exhibit A-23 Schedule M8
Enhance Maximo Capabilities and Processes	p. 18, line 47	pp. 62-65	pp. 155-157
Primary Service Orders Replatform	p. 18, line 48	pp. 173-176	pp. 155-157
External Crew Efficiency	p. 17, line 23	pp. 66-69	pp. 155-157
Work Management and Scheduling Upgrades	p. 18, line 49	pp. 219-222	pp. 155-157
Substation Reporting and Process Enhancements	p. 17, line 20	pp. 203-206	pp. 155-157

7

8 **Enhance Maximo Capabilities and Processes**

9 **Q238. What is Enhance Maximo Capabilities and Processes?**

10 A238. Enhance Maximo Capabilities and Processes is a project aimed at improving and
11 expanding the functionality of Maximo, the Company's Work and Asset
12 Management system, and optimizing its associated processes.

13

14 **Q239. What are the key drivers of Enhance Maximo Capabilities and Processes?**

15 A239. DTEE's Work and Asset Management system, Maximo, has both on-premise and
16 field enabled capabilities. The field portion of that system is currently filled by a
17 field module, EZMax Mobile, that would have been replaced as part of the Maximo

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No.

1 transformation program that is under re-evaluation. With that program now on hold
2 the Company will invest in an upgrade of the EZMax mobile product in 2025 to
3 ensure that users retain the ability to work effectively at the point of activity using
4 an up-to-date product.

5

6 **Q240. What are the benefits of Enhance Maximo Capabilities and Processes?**

7 A240. This project will bring more of the capability of the existing Maximo system to the
8 front line in the form of additional inspection forms, inspection workflows and
9 expanded asset information. Bringing this capability to the field worker will
10 eliminate a portion of the remaining paper-based data collection as well as ensuring
11 that field teams have electronic access to the up-to-date equipment records when
12 performing work making that work safer and more efficient.

13

14 **Primary Service Orders Replatform**

15 **Q241. What is the Primary Service Orders (PSO) Replatform?**

16 A241. The Primary Services Group at DTEE is responsible for working with and assisting
17 many of the Company's largest commercial and industrial customers. To help them
18 perform their work, a web-enabled tracking system that houses primary customer
19 information is used. In addition to being an important tool for the Primary Services
20 Group, other departments such as Regional Relations, MAS, and the Relay Group
21 use this system when working with or for these customers.

22

23 The PSO Replatform project is a 3-year investment beginning in 2024 with a
24 targeted completion in 2026. The scope of the project has 4 major components:

- 25
- Upgrade existing end-of-life primary services web-enabled system.

Line
No.

- 1 • Capture and maintain detailed customer information and electronic primary
- 2 operating orders.
- 3 • Digitize and archive the primary customer infrastructure as-builts and sketches.
- 4 • Build interfaces between the new application and supporting systems, such as
- 5 customer relationship management, enterprise asset management and mapping
- 6 systems.
- 7

8 **Q242. What are the key drivers of PSO Replatform?**

9 A242. Today there are three separate systems required to fully support these functions.

10 The PSO Replatform project will combine all the existing systems into one

11 consolidated system and provide automated connections to other systems that today

12 are not connected. This new system, when fully implemented, will connect with

13 other customer facing systems such as the customer relationship management

14 (CRM), enterprise asset management (Maximo) and mapping systems (ESRI). The

15 current primary services application requires extensive manual processing and data

16 entry, resulting in productivity loss and an inability to keep up with increasing

17 demand. This negatively impacts the customer experience and level of service

18 DTEE can provide.

19

20 **Q243. What are the benefits of PSO Replatform?**

21 A243. The goal of this project is to create a single system that houses primary customer

22 information and equipment needed to isolate customers from DTE Electrical

23 system and vice versa. This system will provide support to field resources with

24 quick access to customer infrastructure and eventual connectivity to ESRI, Maximo

25 & CRM with up-to-date information needed to effectively support primary

Line
No.

1 customer needs. Customers will receive better and faster service and employees
2 will be able to effectively handle more requests faster.

3

4 **External Crew Efficiency**

5 **Q244. What is External Crew Efficiency?**

6 A244. External Crew Efficiency is a category of capital investments targeted at the
7 efficient and cost-effective use of external contract crews used to augment
8 Company crews. The capability to utilize external crews efficiently and cost-
9 effectively is a key component to improving the speed and efficiency of storm
10 restoration. The primary investment in this category is the Utility Restoration
11 Management Application (URMA).

12

13 **Q245. What is URMA?**

14 A245. URMA is an application that will manage crew rosters for external contract crews,
15 track current jobs status and work completed in the field, while enabling visibility
16 into contractor productivity and payment.

17

18 **Q246. What are the key drivers of the URMA application?**

19 A246. The Company relies heavily on external contract crews to support restoration
20 efforts when there is a significant event on the grid, especially during major weather
21 events. As the Company works to improve restoration for customers during storms
22 the command, control and logistics associated with the deployment of those crews
23 has never been more critical. Currently the Company lacks visibility into work
24 performed by non-DTE contract crews and cannot easily measure productivity for
25 these crews. Additionally, the rosters submitted for these crews are not

Line
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1 standardized, many being excel files that are submitted individually, making it
2 challenging to easily view and analyze rosters for all crews. In order to reduce
3 waste and improve productivity, ultimately leading to faster storm restoration, the
4 Company needs improved visibility and monitoring over these crews.

5

6 **Q247. What is the scope of the URMA application?**

7 A247. This is a multi-year project that began in June of 2023 with the first implementation
8 occurring in February of 2024. Delivered in that first implementation was an end-
9 to-end crew rostering application. The rostering application standardizes qualified
10 crew make up and the equipment used at the job site by external contract crews,
11 enabling operational control and the development of cost benchmarking to assist in
12 continuing to reduce overall cost per outage event.

13

14 The next set of investments for 2024 and 2025 are planned to include:

- 15 • Mobile application expansions that will status and ensure workflows for all
16 assigned work.
- 17 • A work completed input form that will document all material used, actual work
18 completed by teams in the field, give visibility on work mix, and validate
19 invoices from external contract crews.
- 20 • Expand rostering capabilities to Baseload contractors, Secure First, Single
21 Damage Assessors, and Damage Assessors to deploy these teams efficiently
22 and accurately.
- 23 • Expand the use of the electronic mobile work application to Baseload
24 contractors, Secure First, Single Damage Assessors, and Damage Assessors.

Line
No.

- 1 • Expand the use of the work completed input form to Baseload contractors,
- 2 Secure First, Single Damage Assessors, and Damage Assessor.
- 3 • Deliver a billing app to document contractor time entries, validate work
- 4 assignments, and expedite accurate invoicing.

5

6 Productivity improvements for outages include:

- 7 • Enhanced functionality in URMA will allow external contract crews to have
- 8 quick electronic access to job specific information (maps, assignments,
- 9 chronology), driving improvements on patrol and restoration times.
- 10 • Real time job status and updates on work required will allow the Emergency
- 11 Field Leaders and Regional Incident Command to take quick action to manage
- 12 crews more effectively.
- 13 • Clear line of sight into crew make-up and available equipment will inform
- 14 resource assignment and optimization.
- 15 • Right-crew to the right job: Contractor resources are currently not optimized
- 16 across restoration work type (i.e., too many contractors on smaller jobs or
- 17 spending too much time on the job). Using Single outage jobs as an example,
- 18 most jobs require only 2 crew members and should be completed in less than 2
- 19 hours.

20

21 **Q248. What are the benefits of the URMA application?**

22 A248. Currently, much of the coordination with external contract crews is manual process-

23 based and not system-enabled. This can lead to gaps in timely visibility into work

24 performed in the field, challenges with the ability to measure foreign and contractor

25 crew productivity, and overall control of those resources in real-time. These

Line
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1 challenges are further exacerbated during major storms. The benefits of URMA
2 include: reduction of waste through improved quality controls and crew validation;
3 improved ability to monitor and audit contractor invoicing to ensure accuracy; and
4 improved visibility of contract crew work scope and real time job statuses. The crew
5 rostering application supports the reduction of waste and improved auditing of
6 contractor invoicing by providing visibility, validation and verification of crew pay
7 rates, crew sizes, and equipment utilized per job. The improved visibility of
8 contract crew work scope and real time job statuses provides the Company
9 leadership increased oversight and ability to monitor performance and drive
10 productivity real time during storm restoration. Additionally, URMA provides
11 more efficient communication of contract crew work assignments directly to the
12 crews, reducing wait time for crews to receive work assignments, and allows
13 contract crews to access job specific information electronically, improving
14 restoration time. The Company has estimated these improvements will drive
15 efficiencies and productivity in storm restoration efforts, reducing the average
16 storm duration by three hours.

17

18 **Work Management and Scheduling Upgrades**

19 **Q249. What Work Management & Scheduling upgrade investments were made in**
20 **2022 and 2023?**

21 A249. Type 2 Customer Communication & Process Efficiency - (Closed Loop) - Phase 2,
22 Contract Agreement System (CAP) Replacement, Maximo Application Suite
23 Upgrade Phase 1 sponsored by Company Witness Sharma, Crew Management
24 Enhancements (2022/2023), multi-year renewal license purchase for ARCOS

Line
No.

1 operator call out application, PMO Primavera upgrade and field operations tools
2 automation are the investments made in 2022 and 2023.

3

4 **Q250. What is the Type 2 Customer Communication & Process Efficiency Closed**
5 **Loop project?**

6 A250. The Type 2 Customer Communication & Process Efficiency – Closed Loop project
7 included the development of a new application designed to track customer type 2
8 damage claim interactions, instances where customers file a claim that the
9 Company damaged their property while performing work. The new application
10 was initiated to improve claim management, communication with customers
11 regarding their claim, and reduce overall process cycle time for customers.

12

13 **Q251. What are the key drivers of Type 2 Customer Communication & Process**
14 **Efficiency?**

15 A251. The Damage Claims group historically utilized multiple systems, or tools such as
16 Excel, to manage damage claims and communicate updates to customers. These
17 systems were not integrated, nor did they provide visibility to all key stakeholders
18 and customers. The cycle time to resolve damage claims was on average 60-90
19 days, and there was no automated way to send customers standard updates
20 throughout the process and when claims were closed. Additionally, when customers
21 called into the DTEE call center, the call center representative did not have
22 visibility into a claim status and could not provide the customer information
23 regarding a claim. As a result, the Company received complaints from customers
24 about the damage claims process.

25

Line
No.

1 **Q252. What are the benefits of Type 2 Customer Communication & Process**
2 **Efficiency?**

3 A252. With the completion of this project claims are tracked and processed centrally
4 through the new application which includes all case information and is integrated
5 in the Company's customer relationship management system (CRM). This
6 includes a validation tool for customers to confirm their claims have been
7 submitted, a feedback loop for customers once claims have been resolved, and a
8 one stop repository for both active and resolved claims. This investment improved
9 the response time for damage claims resolution, with the average response time
10 dropping from an average of 60-90 days down to 23 days in 2023. Additionally,
11 this system is integrated with the Company's CRM, which allows customer service
12 representatives in the call center to see claim statuses and provide customers
13 updates as requested. This investment also enabled the Company to automatically
14 send weekly communications to customers regarding claim status updates and a
15 communication when a claim has been resolved through various methods such as
16 letters, texts and calls. In 2023, 100% of customers that filed a claim were
17 communicated to upon claim resolution.

18

19 **Q253. What is the Contract Agreement System (CAP) Replacement?**

20 A253. In 2022 the Company began a project to replace the existing Contract Agreement
21 System (CAP). That system was an internally created program which was no longer
22 meeting the needs of the business unit. The system did not have the capability to
23 easily create new agreement types and had no electronic document signing or
24 interchange mechanisms.

25

Line
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1 **Q254. What are the key drivers of CAP Replacement?**

2 A254. The Company enters into over \$3 million dollars a year in contracts for new
3 business and construction/service work. The current system is limited in the
4 information it provides and inefficient, it does not include automated workflow for
5 timing, nor does it have alerts to assist the contracts team in understanding when
6 any step in the process has taken longer than expected to complete. This can result
7 in extended construction service times and negatively impact customers that are
8 attempting to have services performed by the company on their behalf.

9

10 **Q255. What are the benefits of CAP Replacement?**

11 A255. This system helps the Company remain compliant with service levels related to
12 timing for new business and construction/service work for customers. In addition,
13 it provides the flexibility to create new types of agreements, allows more rapid
14 process improvements more easily than the previous system, and has improved
15 worksheet operability covering 15 electric service and construction agreements. For
16 customers, this translates into more efficient contract approval, a simplified
17 electronic routing processes for document management and leverages DOCUSIGN
18 for electronic signature to improve the customer experience.

19

20 **Q256. What is Crew Management Enhancement?**

21 A256. Crew Management Enhancement is a Crew Rostering system for DTEE crews that
22 replaced the outdated Crew Rostering system and will be integrated into the URMA
23 application as it goes into service. This is crucial for the Company's operational
24 groups to effectively build, manage, and deploy crews while adhering to union

Line
No.

1 agreements and maintaining DTEE's commitment to safe, timely, and qualified
2 service.

3

4 **Q257. What are the key drivers of Crew Management Enhancement?**

5 A257. DTEE employs processes and systems for resource management of internal DTEE
6 crews. The two-year project brought significant improvements, including
7 infrastructure updates, enhanced crew visibility, automated tracking of overtime
8 and training, adjustments for union contracts, and the integration of apprentice
9 rostering without manual intervention. Additional enhancements in 2024 and 2025
10 is part of the External crew efficiency project.

11

12 **Q258. What are the benefits of Crew Management Enhancement?**

13 A258. The capacity to efficiently roster and deploy crews ensures that work can be
14 accomplished with greater safety and speed.

15

16 In 2022, the system transitioned to new infrastructure, improving performance, and
17 features such as visible crew resources, automated overtime and training tracking,
18 and integration of vacation calendars were introduced. A visual dashboard
19 increased crew availability visibility, and record-keeping for employee OT
20 scheduling improved.

21

22 Continuing into 2023, continuous improvement led to additional enhancements, a
23 dedicated training environment, adaptability to changes in union contracts, Fleet
24 Organization integration for calendaring and OT reporting, and expanded
25 management-level reporting. The introduction of a training environment allowed

Line
No.

1 users to train on the rostering system beyond initial introductory training. With the
2 ability to effectively roster and deploy crews, work will be done more safely and
3 quickly.

4

5 **Q259. What is PMO P6 Primavera Refresh project?**

6 A259. PMO P6 Primavera Refresh project is an upgrade from the current unsupported
7 version of Primavera Scheduler used by DO Scheduling and DO PMO Groups to
8 the newest version of Primavera. In addition, the project includes the replacement
9 of the current WTA (Walter Tanner & Associates) interface between Primavera and
10 Maximo with an industry standard product called Maxavera.

11

12 **Q260. What are the key drivers of PMO P6 Primavera Refresh?**

13 A260. Primavera is the scheduling software used by DTEE's DO Scheduling and PMO
14 Groups to manage and execute the entire DO strategic capital investment. The
15 current version of Primavera used by DO Scheduling and PMO was 16 major
16 revisions behind and unsupported by the vendor. If the software were to crash, DO
17 Scheduling and PMO would lose the ability to manage the DO strategic capital
18 portfolio, affecting critical capital investments in the grid.

19

20 **Q261. What are the benefits of PMO P6 Primavera Refresh?**

21 A261. The upgraded Primavera version (and Maxavera interface product) will eliminate
22 data latency that is currently present with the Primavera and Maximo systems and
23 provide a more robust application. It will also bring the DO PMO group to the
24 same version of the scheduling product as the corporate project management office
25 is using allowing fee exchange and interoperability of schedules across all DTEE.

Line
No.

1 **Q262. What is the Multi-year Renewal license purchase for ARCOS?**

2 A262. DTEE has utilized the ARCOS Callout solution for several years, necessitating
3 frequent license renewals. Recently, the company successfully negotiated a
4 comprehensive 5-year agreement during the latest renewal, preventing year-over-
5 year cost increases and ensuring elevated warranty support throughout the period.

6

7 **Q263. What are the key drivers of Multi-year Renewal license for ARCOS?**

8 A263. The ARCOS license was expiring, and the Company was facing potential cost
9 increase for future licenses. This system is crucial for the Substations group to
10 conduct after-hours callouts while adhering to collective bargaining agreements
11 and union rules.

12

13 **Q264. What are the benefits of Multi-year Renewal license for ARCOS?**

14 A264. This investment ensures the continuity of an operational callout system,
15 maintaining efficiency and reliability in managing after-hours dispatching for the
16 substations group. By negotiating a 5-year agreement the company was able to
17 reduce future cost increases for licenses and obtain elevated warranty support.

18 The ARCOS system itself enables timely and accurate job callouts, reducing
19 response times for substations employees to respond emergent issues on the grid.

20

21 **Q265. What is Field Operations Tools Automation?**

22 A265. Field Operations Tools Automation is an investment undertaken to replace existing
23 operational tools, applications and dashboards that perform important operational
24 control functions but that no longer have the capability to support DTEE's rapidly
25 evolving operational processes. Some DO apps use extremely old technology and

Line
No.

1 utilize on-premises servers. These apps are built on 20-year-old foundations, such
2 as classic ASP and PHP, which substantially increases maintenance cost. The
3 objective is to automate manual efforts and reduce reliance on managing operations
4 through excel spreadsheets.

5
6 In 2023, a project to develop a system for use in confirming Customer Power Status,
7 particularly in-line with restoration efforts was in place. The project created a
8 facility to visualize the power status of meters at Customer sites along with the state
9 of the communications devices necessary to backhaul the data to DTE. This utility
10 gives insights to analysts tasked with determining why the current power state at a
11 customer site is unknown and facilitates detection of nested outages or field
12 communication devices that may need repair.

13

14 **Q266. What are the key drivers of Field Operations Tools Automation?**

15 A266. As the Company continues to work to improve its operations both in normal
16 weather conditions and during increasingly frequent weather events it continues to
17 rely upon both departmental applications and internally built solutions. Many of
18 these solutions do not scale and are not serving current or emerging needs
19 adequately. Several systems that measure day-to-day performance are dependent
20 on manual steps and do not have a consistent approach to data management. Report
21 generation is not consistent between groups/regions/service centers. This leads to
22 process inefficiencies and reduces situational awareness. The Field Operations
23 Tools Automation project was undertaken to begin to select the most important of
24 these use cases and automate them in an effective and supportable manner.

Line
No.

1 Increasing automation in these activities will increase visibility into process
2 adherence, help better identify gaps and improve situational awareness.

3

4 **Q267. What are the benefits of Field Operations Tools Automation?**

5 A267. For customers, this investment will result in tighter control of field events, more
6 information in the hands of crews to be shared with customers at their work
7 locations and improved response and restoration times during outage events.
8 Employees will be able to minimize usage of and reliance upon cumbersome
9 manual processes, add new opportunities to collaborate when reviewing/ sharing/
10 editing, and tracking activities. Instances of duplicative effort and human error will
11 be reduced. Team members can focus on value-add versus manual activities.

12

13 The 2023 efforts around CPS facilitated faster detection of on-going electric service
14 and communication network issues that can impact a customer's service restoration
15 and timely notifications. It was important to undertake the project in the time frame
16 it was executed to provide supporting insights to the larger Customer Power Status
17 Visualization (CPSV) program efforts designed to improve DTEE's outage
18 detection and service restoration efforts.

19

20 **Q268. What are the new investments planned for 2024 and 2025 in the Work**
21 **Management & Scheduling upgrade category?**

22 A268. The planned investments in the work Management & Scheduling upgrade category
23 for 2024 and 2025 are: Circuit ownership app, Wiredown Associated Call
24 Enhancement, and moving Mobile timesheet (MTS) Data to cloud.

- 25
 - Circuit Ownership application:

Line
No.

1 The Circuit Ownership App is a new tool that consolidates data to a central location
2 for the Circuit Owner's comprehensive review. This data encompasses AMI Meter
3 Data, SCADA Data, Circuit Maps, current Maximo Work Orders in the field, and
4 Damage Assessment Information.

5 The new tool will facilitate a centralized contact accountable for real-time circuit
6 performance, strategizing, and advocating for the circuits. This strategy may
7 involve both short-term reliability projects (completed in under a year) and
8 extensive multi-year reliability projects.

9 The identified benefits include a streamlined process, reducing engineers' time
10 navigating various systems, resulting in quicker analysis and decision-making for
11 service-affecting issues on the circuits they oversee.

12

13 • Wiredown Associated Call Enhancement:

14 The company frequently receives redundant reports of wires down in the field,
15 resulting in the creation of multiple jobs in OMS. This causes delays and
16 unnecessary truck rolls.

17 The Wiredown Associated Call Enhancement investment involves updating the
18 OMS to efficiently link wiredown jobs, reducing wasted truck rolls and enhancing
19 productivity. The Field Service Edge application will be modified to display
20 associated calls on a job, enabling crews to access necessary data for safe evaluation
21 of wire down incidents and addressing public safety concerns. This enhancement
22 aims to streamline and enhance the efficiency of wiredown job responses.

23

24 • Moving mobile time sheet (MTS) data to Cloud:

Line
No.

1 Presently, the Company can observe general time sheet charges and manually delve
2 into specifics for OH/UG crews for an event requiring a truck roll.

3 The new cloud-based data will allow the OH/UG teams to automate reports on
4 detailed crew time charges, enhancing our understanding of defect codes like wait
5 time. Utilizing the cloud data platform will integrate disparate sources, such as
6 Mobile Timesheet charges and Outage Management events, enabling automated
7 reporting dashboards for timely field productivity visibility.

8 The implementation of this system can eliminate approximately 2 hours of daily
9 manual work for four individuals, equivalent to a full-time Operations Analyst
10 position worth \$80,000 per year. This will not completely offset the position, but
11 provides an opportunity for more productive and analytical tasks. Additionally, it
12 increases the capacity to run reports for all Service Centers, saving time and
13 identifying opportunities to enhance field productivity, both in storm and non-storm
14 scenarios.

15

16 **J. Asset Management**

17 **Q269. What is Asset Management?**

18 A269. Asset Management is a category of investments that involve utilizing technology
19 to support effective asset management. These investments include projects that
20 support managing physical assets, such as personal protective gear and large fleet
21 vehicles, as well as projects that support electronic asset data management.

22

23 **Q270. Where are the capital investment details of the projects and programs in this**
24 **category?**

Line
No.

1 A270. Capital investment details of these projects and programs in this category are
2 included in:

- 3 • Exhibit A-12, Schedule B5.4, page 17-18
- 4 • Exhibit A-23, Schedule M7

5

6

Table 11 Asset Management Exhibit Locations

Program/Project	Exhibit A-12 Sch. B5.4	Exhibit A-23 Schedule M7	Exhibit A-23 Schedule M8
Systematic Tracking of Rotatable Assets	p. 17, line 22	pp. 207-210	pp. 157-159
Asset Management Upgrades	p. 17, line 21	pp. 21-24	pp. 157-159

7

8 **Systematic Tracking of Rotatable Assets**

9 **Q271. What is the Systematic Tracking of Rotatable Assets?**

10 A271. This new investment in 2025 includes developing and implementing a digital
11 tracking repository for items like personal protective equipment that have
12 expiration dates and must be managed through their deployed life cycles. It
13 improves the accuracy, efficiency, and accountability on the movement of materials
14 within a process. Examples include Field tracking of assets using RFID (radio
15 frequency identification trackers) readers on trucks, in warehouses and tracking
16 rubber goods (sleeves and gloves used by line workers) for front line employees.
17 Benefits include decreasing the risk of having outdated assets in the field, and
18 improving the accuracy, efficiency, and accountability on the movement of
19 materials within a process.

20

21 **Q272. What are the key drivers of Systematic Tracking of Rotatable Assets?**

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1 A272. Field tracking of assets that must be rotated in and out of the field on a regular
2 cadence and the record keeping needed to ensure that none of them remain deployed
3 beyond their expiration date is a key and critical component of DTEE's overall
4 safety program. Prior to this investment, these assets were being tracked manually.
5 A practice subject to human performance or tracking errors.

6

7 **Q273. What are the benefits of Systematic Tracking of Rotatable Assets?**

8 A273. Ensuring that all PPE is current and safe to use will reduce the likelihood of injury
9 to workers, a core value of the Company.

10

11 **Asset Management Upgrades**

12 **Q274. What is the Brigade 360 Cameras Project?**

13 A274. The Brigade 360 cameras project was an investment specifically undertaken to
14 reduce the occurrence of motor vehicle accidents and improve crew and facility
15 safety. This included installing 360-degree cameras on Distribution Operations
16 vehicles. These cameras provide additional views that allow drivers to see aerial
17 equipment hazards.

18

19 **Q275. What are the key drivers of the Brigade 360 Cameras Project?**

20 A275. DTEE's bucket and digger trucks represent a significant investment on the road,
21 and due to their size and driver visibility have some inherent challenges with
22 impacts of low hanging tree limbs, awnings, etc. Safeguarding these assets and
23 ensuring their operational efficiency is crucial for success, especially when
24 considering the limited availability of trucks in the overall market. This technology
25 investment provides for both real-time and recorded imagery for crews and allows

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1 them to operate their vehicles with more situational awareness and higher levels of
2 safety. Between 2022 and 2023, 550 heavy-duty vehicles, 37 medium-duty
3 vehicles, and 69 light-duty vehicles were fitted with the Brigade 360 cameras.
4 Approximately 60 bucket trucks and 250 light trucks in the fleet are awaiting fitting
5 of the system.

6

7 **Q276. What are the benefits of the Brigade 360 Cameras Project?**

8 A276. Impacts with tree limbs and overhead structures happens typically more than a
9 dozen times per year and can cost as much as \$3,500 each time to repair the bucket
10 and other parts of the vehicle.

11 The Company made this investment with the goal of decreasing motor vehicle
12 incidents, measured by the Collisions per Million Miles (CPMM) metric. Since
13 inception, motor vehicle accidents have decreased from 140 (2022) to 119 (2023),
14 marking a 17% improvement. It's crucial to note that factors like inclement weather
15 and road conditions affect this metric, and this investment is part of a broader effort
16 to enhance vehicle safety. Lowering vehicle incidents not only enhances public
17 safety but also reduces expenses associated with repairing or replacing damages,
18 contributing to overall affordability of products.

19

20 **K. Mobile Technology**

21 **Q277. What is Mobile Technology?**

22 A277. Mobile Technology is a category of investments focused on creating seamless
23 transitions between on-line and off-line operations and provide integrated
24 communication, including workflows, between the control room, field leaders, field
25 crews, and supporting organizations. Mobile capabilities include both devices and

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1 applications that are engineered for mobile access and usage. Applications include
2 dispatch, work execution and forms digitization, location tracking, route
3 navigation, analytics, and secure file sharing.

4

5 **Q278. Where are the capital investment details of the projects and programs in this**
6 **category?**

7 A278. Capital investment details of these projects and programs in this category are
8 included in:

- 9 • Exhibit A-12, Schedule B5.4, page 17-18
- 10 • Exhibit A-23, Schedule M7

11

12 **Table 12 Mobile Technology Exhibit Locations**

Program/Project	Exhibit A-12 Sch. B5.4	Exhibit A-23 Schedule M7	Exhibit A-23 Schedule M8
Mobile Tools Expansion	p. 18, line 50	pp. 116-119	pp. 133, 159-161
Maintain Compliance	p. 18, line 51	pp. 96-99	pp. 133, 159-161
Enhance and Expand Cybersecurity	p. 18, line 52	pp. 58-61	pp. 133, 159-161
Mobile Equipment Replacement	p. 18, line 53	pp. 108-111	pp. 133, 159-161
Mobile Technology	p. 18, line 54	pp. 112-115	pp. 133, 159-161

13

14 **Mobile Tools Expansion**

15 **Q279. What is Mobile Tools Expansion?**

16 A279. Mobile Tools Expansion is a category of investments related to tools and
17 applications utilized by field resources. Mobile tools are a critical investment to

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1 support operational crews and leadership drive efficiency, productivity, and safety.

2 The primary investment in this category is the Every Day Daily Plan (EDDP).

3

4 **Q280. What is Every Day Daily Plan (EDDP)?**

5 A280. The Everyday Daily Plan is a web application designed to serve as a consistent
6 "all-weather" tool for both storm and non-storm scenarios. This tool facilitates the
7 Company's response to planned and trouble work on the electric system, utilizing
8 real-time data to bundle and prioritize jobs. Customizable inputs allow for the
9 escalation of variable customer needs, such as Election Day Polling Locations and
10 School Count Day. The EDDD will work in tandem with an auto-assign function,
11 driving optimization of job and crew dispatch for the first job of the day.

12

13 **Q281. What are the key drivers of EDDP?**

14 A281. After the 2023 catastrophic ice storm the Company undertook a series of actions to
15 take advantage of system capabilities and opportunities that were never possible
16 prior to the replacement of the outdated OMS system in February of 2023. The
17 lessons learned during that storm and the capabilities that the new systems offered
18 allowed DTEE to explore opportunities within its mobile tools, which will
19 ultimately dramatically transform the ability to serve customers quickly and safely
20 as power is restored after significant storm events. This EDDP was begun as one
21 of multiple ways that DTEE will bring new capability to field teams. Historically,
22 planning and prioritizing work for the day involves using multiple databases,
23 human performance for priority evaluation, and manual phone calls. Additionally,
24 the prioritization and bundling of work during a storm utilized different tools than
25 normal operations day to day work. During storm situations a team of five

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1 individuals worked 16 hour shifts through the night manually developing a storm
2 restoration plan for the next day. Also, during storm and during normal operations
3 the first job a crew received was manually dispatched to the crews, at times causing
4 delays for crews getting to their first job of the day, especially during high event
5 days and storms. The EDDP enables the automation of several processes, such as
6 prioritization, bundling and auto-assigning work of work, reducing manual work
7 and driving efficiency. This ultimately improves crew efficiency and enables crews
8 to get to their first job quicker, reducing restoration time for customers.

9

10 **Q282. What are the benefits of EDDP?**

11 A282. The EDDP streamlines storm and normal operations daily planning processes,
12 creating one standard process used during all weather events. This tool automates
13 daily work prioritization, budling and dispatching of the first event of the day to
14 crews in the field. The automation of this work reduces manual labor and individual
15 decision making, drives efficiency through bundling of work and geographically
16 routing, and improves restoration efforts through faster dispatching of jobs in the
17 morning. The tool will seamlessly integrate all crews, of all types, into flexible and
18 timely daily plans. The EDDP will reduce an average one hour a day per crew in
19 wait time for their first job of the day, increasing productivity and reducing
20 restoration time for customers.

21

22 **Maintain Compliance**

23 **Q283. What is Maintain Compliance?**

24 A283. DTE Electric is subject to multiple regulatory authorities and must maintain
25 compliance with the MPSC, FERC, NERC and other industry regulations and

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1 orders. The level of regulatory and industry oversight has grown to the point that a
2 program is being undertaken to ensure successful compliance. This investment is
3 expected to grow year-over-year, especially beyond 2025 when the Company
4 anticipates the need for additional compliance components to be required on several
5 topics including but not limited to energy justice (EJ), electrification, cyber security
6 and expanding NERC requirements. Having access to accurate, timely and
7 complete operational data is key for compliance. System investments to compile
8 day-to-day operational information and demonstrate compliance are needed to
9 replace labor intensive manual methods that have been used to date.

10

11 **Q284. What are the key drivers of Maintain Compliance?**

12 A284. Real-time operational data enables DTEE to adapt to changing regulations and
13 demonstrate adherence to those changes. Investing in compliance automation to
14 meet new demands and having data accessible in a timely and cost-effective manner
15 for reporting are some examples as to why this investment is prudent.

16

17 **Q285. What are the benefits of Maintain Compliance?**

18 A285. Like any other industry the Company stewards a body of sensitive data required for
19 effective operations. This data includes electrical system, operational, customer,
20 and payment data. Many regulations and compliance mandates govern the
21 Company's use of this information and how it must be safeguarded. DTEE's
22 customers benefit from this investment when the information is collected, used, and
23 secured in such a way that the information is safeguarded both within Company
24 facilities and when in the hands of DTEE employees while serving the customer at
25 their location. Employees benefit by having ready access to the information needed

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1 to serve wherever the work requires, knowing that mobile systems comply with all
2 the regulations that govern their job functions.

3

4 **Enhance and Expand Cybersecurity**

5 **Q286. What is Enhance and Expand Cybersecurity?**

6 A286. The Company plans to invest hundreds of millions of dollars in its grid automation
7 programs over the next decade. The automation that is placed in the field to enable
8 that automation and control must be protected from cyber-attack and that protection
9 presents unique and ever evolving challenges as bad actors will recognize this field
10 automation as a potential that they will look to exploit. This project is designed to
11 place targeted technologies, both hardware and software, into the Company's
12 infrastructure in a controlled manner to test and evaluate the most effective ways to
13 address these threats.

14

15 **Q287. What are the key drivers of Enhance and Expand Cybersecurity?**

16 A287. Industry-wide there is recognition both for the need to automate the ever evolving
17 and more complicated grid to control it in real-time and that this automation will
18 create potential vulnerabilities for outsiders to exploit. If these potential threats are
19 not addressed early in automation programs, then the opposition will gain a
20 significant advantage over the Company's ability to safely operate the grid. This
21 program will assess the cybersecurity needs for this infrastructure and inform the
22 selection of tools and techniques to combat these threats.

23

24 **Q288. What are the benefits of Enhance and Expand Cybersecurity?**

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1 A288. Adequately understood and implemented tools and countermeasures will serve to
2 ensure that the grid is as reliable, available, and defensible as possible. Customers
3 will benefit from a more resilient, more effectively run grid, while at the same time
4 this project will be foundational in ensuring that only the authorized operators are
5 able to access and control the automation that is put in place. This is critical from
6 both a safety and an operational standpoint.

7

8 **Mobile Equipment Replacement**

9 **Q289. What is Mobile Equipment Replacement?**

10 A289. The Company has thousands of mobile devices that have been deployed to front-
11 line workers and their leadership. These devices have planned useful deployed
12 lifecycles of 6 years. The Company plans and executes device replacements yearly
13 on ~1/6th of those devices to keep the devices operational and secure.

14

15 **Q290. What are the key drivers of Mobile Equipment Replacement?**

16 A290. Up to date devices are more reliable and technically secure from cyber threats than
17 older, less capable equipment. It is important for field workers to have operational
18 and up-to-date equipment to perform their work functions safely and effectively.

19

20 **Q291. What are the benefits of Mobile Equipment Replacement?**

21 A291. Correctly functioning equipment running effectively, and up-to-date systems
22 contribute to efficient processes and work completion, an advantage to customers
23 in terms of DTEE's ability to be responsive to their needs and helps shorten outage
24 restoration times.

25

Line
No.

1 **Mobile Technology**

2 **Q292. Why has the Company chosen to represent its Mobile Technology spend more**
3 **specifically in this rate case?**

4 A292. In previous rate cases, Mobile Technology was represented in the financial exhibit
5 as the sum of several included projects and talked about at that higher level.
6 Feedback from the commission and the types of discovery questions from
7 intervenors indicate that a more itemized approach was desired so for this case that
8 category has been reworked to itemize its key investments.

9

10 **Q293. What were the key investments made in 2022 and 2023 that are Mobile**
11 **Technology?**

12 A293. The key investments grouped under the heading of Mobile Technology were
13 Outage Status App Changes for Damage Assessment, Tree Trim's Vegetation
14 Management Software Replacement Pilot Project, Service Center Wi-Fi Upgrades,
15 Lemur Pro Multiyear License Purchase and Field Service Edge Overhead
16 (OH)/Underground (UG) Enhancements.

17

18 **Q294. What is Outage Status App Changes for Damage Assessment?**

19 A294. The scope of this project was to create a capability within the Outage Status
20 Application (OSA), the mobile storm tool used by DTEE's tree trim and all foreign
21 crews for storm response, allowing automated near real time access to update
22 damage assessment from the field to planning staff.

23

24 **Q295. What are the key drivers of Outage Status App Changes for Damage**
25 **Assessment?**

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1 A295. Over the last several years the amount and severity of damage caused by storm
2 events has increased as weather in Michigan changes for the worse. It is critical
3 that damage assessment teams get into the field and get their data back to planning
4 staffs as rapidly as possible immediately following an event. get. This project adds
5 damage assessment capability to one of DTEE's key field tools that it previously
6 did not incorporate. With the inclusion of this capability, the automated damage
7 assessment form is accessible by all damage assessors to record and provide
8 information on outage events with this information flowing into the OMS system
9 in real time as the form is completed and sent electronically.

10

11 **Q296. What are the benefits of Outage Status App Changes for Damage Assessment?**

12 A296. Having damage assessment data rapidly available allows the Company to plan
13 restoration work more accurately for any given outage event. This information
14 provides crews with advance knowledge about what types and quantities of
15 materials they may need due to the assessor's detailing of the actual location and
16 severity of the damage that has occurred. This benefits the customer in faster
17 restoration times and more accurate estimates. It also advantages the Company's
18 employees as advance notice of this kind improves the safety of the workers and
19 the efficiency of logistic response at the point of damage. A final benefit comes
20 from use of the damages assessment data to predict the needs for future events.
21 Where this data is available, it can be used to model future events and improve
22 work standards and processes. If damage levels in advance of an incoming event
23 can be better predicted, then the ability to have the right number of resources
24 deployed at the right locations will continue to improve response times, repair
25 effectiveness, and overall cost per event.

Line
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1 **Q297. What is Tree Trim's Vegetation Management Software Replacement Pilot**
2 **Project?**

3 A297. The Company's existing Vegetation Management system is approaching end of life
4 and will need to be replaced within the next 3-4 years. This pilot project is a key
5 component in selecting an appropriate replacement that will fulfill the business
6 outcomes needed for achieving and maintaining a 100% on cycle trimming program
7 and helping to move the Company to predictive on demand vegetation
8 management.

9

10 **Q298. What are the key drivers of Tree Trim's Vegetation Management Software**
11 **Replacement Pilot Project?**

12 A298. The replacement of DTEE's existing Vegetation Management tool will be a
13 multiyear, multi-million-dollar investment. The Company solicited multiple
14 companies through a formal RFP and selected an initial preferred partner. To verify
15 this selection a pilot project was undertaken to demonstrate the capabilities of that
16 selected software to further validate the selection before accepting the final
17 statement of work for the larger program. The activities within the pilot will allow
18 the team to experience firsthand the software, participate in configurations based
19 on key business requirements, experience onsite training, perform device setup,
20 engage in ongoing Q&A and evaluate vendor support throughout pilot program.
21 All these activities will validate the front runner's solution in the Company's
22 environment and shorten overall implementation of a final product. Choosing a
23 vendor without piloting the software beforehand may lead to receiving a product
24 that does not meet expectations.

25

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1 **Q299. What are the benefits of Tree Trim's Vegetation Management Software**
2 **Replacement Pilot Project?**

3 A299. The pilot program is a key piece in evaluation of a potential work management
4 software replacement for Tree Trim. The pilot will highlight key business
5 functionality requirements for field and back-office users, with the goal of finding
6 and addressing any functionality discrepancies between the RFP requirements and
7 the actual vendor product prior to the beginning of the project.

8

9 **Q300. What is the scope of the Service Center Wi-Fi Upgrades?**

10 A300. The project scope was to upgrade current Wi-Fi Infrastructure at all Service Centers
11 including Warren and the Technical Development center (TDC). It included
12 installation of additional Wi-Fi capacity / coverage. With increase of over 100%
13 in the number of mobile devices in use by teams at decentralized locations (MDTs,
14 laptops, tablets, and phones) and the increase in the size of the area that had to be
15 covered at each location, the existing Wi-Fi footprint and capacity had to be
16 increased. Addressed coverage issues inside the building and reconfigured existing
17 layout to meet updated requirements. The project also added outdoor coverage in
18 the parking areas, truck bays and garages.

19

20 **Q301. What are the key drivers of Service Center Wi-Fi Upgrades?**

21 A301. Service Center demand on Wi-Fi has increased over time. Existing capacity and
22 area of coverage was no longer sufficient to support the increased usage of mobile
23 devices like MDTs, laptops, tablets, and phones. It became necessary to increase
24 indoor and outdoor Wi-Fi capacity and coverage at 15 locations (13 Service
25 Centers, Warren Center and the TDC.) Field personnel will be able to connect to

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1 proper applications and will have appropriate bandwidth to run applications and
2 obtain data on the network.
3

4 **Q302. What are the benefits of Service Center Wi-Fi Upgrades?**

5 A302. With this investment employees will be able to use their mobile tools anywhere on
6 service center property to transfer data and software updates. The original Wi-Fi
7 designs at these locations were built with the assumption that any data intensive
8 transfers (e.g., maps, software patches, and operating system updates) to mobile
9 devices would be accomplished through a wired interface with only. This limited
10 how often and how time consuming these transfers were, which in turn limited the
11 number of changes that were made. As business needs have evolved and the
12 frequency of these activities has increased a different solution was needed. As a
13 result, the process for these activities went from monthly or quarterly wired updates
14 to on demand wireless ones. This is now possible as this technology has matured,
15 and its capabilities have improved. Wireless has the capacity to deliver large
16 updates and handle hundreds of connections over longer distances.
17

18 **Q303. What is Lemur Pro License Purchase and why is it necessary to have these**
19 **licenses?**

20 A303. Purchase of 3-year Lemur Pro license renewal was completed in 2023. Lemur Pro,
21 from Locana, is the application used by the OH/UG/PSR field resources to access
22 the As-Built maps of the electrical system. It provides access to the maps and
23 equipment attribute information in both connected and disconnected/offline
24 conditions. Crews can see the location of their work in relation to circuits and other
25 equipment as well as the location of other crews and contractors.

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1 **Q304. What are the key drivers of Lemur Pro License Purchase?**

2 A304. By purchasing a 3-year license agreement with Locana the Company, and by
3 extension the customers, can be protected From unanticipated price increases and
4 by ensuring the level of warranty support that is provided by DTEE's vendor
5 partner.

6

7 **Q305. What are the benefits of Lemur Pro License Purchase?**

8 A305. Cost containment and Warranty support inclusion are the main benefits of this
9 investment.

10

11 **Q306. What is Field Service Edge (FSE) for Overhead and Underground crews?**

12 A306. Field Service Edge (FSE) was deployed in Feb 2023 for electric field operations
13 and Overhead (OH) and Underground (UG) crews. The FSE mobile application is
14 being used to allow OH/UG field resources to receive trouble job assignments and
15 details associated with those jobs. At the initial launch, the Company had
16 implemented the same feature set that was originally planned for the Compass
17 mobile tool before Compass was retimed to after go-live. Once in place and in use
18 it was determined that this tool could enable additional features that would
19 contribute to improved storm restoration efforts.

20

21 **Q307. What are the key drivers of FSE for OH/UG?**

22 A307. After the catastrophic ice storm in February of 2023 the Company focused on
23 improving storm restoration processes. Adding additional capability to the primary
24 field tool was determined to be an important investment. This led to a series of
25 enhancements to the system based on storm improvement efforts and feedback from

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1 the field and dispatch teams on improvements to the usability of the FSE mobile
2 app.

3 Some of the Field Service Edge (FSE) enhancements that were deployed to the
4 overhead/underground field crews in 2023 include:

- 5 • Consolidated input screens: Changes in how field crews will handle accelerated
6 storm restoration led to an opportunity to consolidate some of the input screens
7 that the crews interact with and ensures that all of them most important
8 information in a simplified workflow.
- 9 • Added an assignment prioritization grid view that closely mimics that same
10 functionality at a dispatchers station in the OMS. This view now highlights
11 priority jobs, allows sorting and filtering to help crews focus during storms
12 rather than a first in first out flow that was typical of the original product
13 delivery.
- 14 • Implemented bulk updates and quick completions for common issues.
- 15 • Added the ability to view all the crew's current assignments on a map to assist
16 in geographically tracing wire downs and circuit issues. This type of analysis
17 function was previously found at the dispatch level, but this allows movement
18 of that awareness and decisioning to the point of activity.
- 19 • Simplified the meter exchange job flow and allowed bar code scanning for
20 serial numbers to accomplish routine tasks often associated more rapidly with
21 restorations.
- 22 • Added link to report of all crews working on the same circuit to help with
23 situational awareness.
- 24 • Improve data quality by enabling required functionality for specific data fields
25 and formatting of data being sent back to OMS.

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1 **Q308. What are the benefits of FSE for OH/UG?**

2 A308. The above-described enhancements to workflows and screen consolidations have
3 been implemented, all of which are integral components to improve storm
4 restoration efforts.

5

6 **Q309. Does this complete your direct testimony?**

7 A309. Yes, it does.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-21534

REBUTTAL TESTIMONY

OF

SHANNEN M. HARTWICK

DTE ELECTRIC COMPANY
REBUTTAL TESTIMONY OF SHANNEN M. HARTWICK

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 Shannen M. Hartwick (she/her/hers), Director of Conversion Projects,
 4 One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy
 5 Corporate Services, LLC, a subsidiary of DTE Energy Company.

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 of the Attorney
 14 General (AG), Michigan Environmental Council (MEC), and Natural Resource
 15 Defense Council (NRDC), collectively referred to as “AG-MN” Witnesses
 16 Stephens and Alvarez, and Michigan Public Service Commission (MPSC or
 17 Commission) Staff (Staff) Witness DeCooman. The absence of a discussion of
 18 other matters in my testimony should not be taken as an indication that I agree with
 19 all other aspects of intervenor testimony.

20

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

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

<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
A-53	RR1	Discovery Response – MNSCDE-7.1(c)
A53	RR2	Automation Prioritization Tool

Line
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1 **Q5. Were these exhibits prepared by your or under your direction?**

2 A5. Yes, they were.

3

4 **Q6. How is your testimony organized?**

5 A6. There are twelve specific issues I will rebut in my testimony, as listed below. A
6 detailed discussion of why the intervenor's recommendations should not be
7 accepted by the Commission follows.

8

9 **Rebuttal Contents**

10	Purpose of Testimony	1
11	Part I - Distribution Automation	3
12	Rebuttal Issue 1: AG-MN Stephens' claim that DTE provides no measurable safety	
13	basis to support investments is incorrect based upon the safety data provided	5
14	Rebuttal Issue 2: AG-MN Stephens' claim that there are five Drawbacks of	
15	Automation	8
16	Rebuttal Issue 3: AG-MN Stephens' specific recommendation for a Distribution	
17	Automation benefit-cost model, as opposed to the currently used prioritization tool	
18	supporting Distribution Automation	13
19	Part II - Grid Automation Telecommunications	17
20	Rebuttal Issue 4: AG-MN Witness Stephens and Alvarez's recommendation to	
21	disallow strategic capital associated with Grid Automation Telecommunications is	
22	inappropriate due to prior approvals and support for 2024 and 2025 investments.....	17
23	Table 1 - Grid Automation Telecommunications Request (000s)	20
24	Rebuttal Issue 6: AG-MN Witness Alvarez states "DTE refused to provide the [Grid	
25	Automation Telecommunication] Plan" despite the Company providing details for our	
26	2024 and 2025 investments.....	21
27	Rebuttal Issue 7: AG-MN Witness Alvarez's opinion that the Alternative Analysis	
28	provided in the instant case failed to meet the Commission's previous request is	
29	incorrect based upon the record.	25
30	Rebuttal Issue 8: AG-MN Witness Alvarez's recommendation for Benefit-Cost or	
31	Make vs. Buy Analysis is inappropriate for investments within the test year.....	28
32	Table 2 - Make vs. Buy Characteristics	29
33	Rebuttal Issue 9: AG-MN Witness Alvarez's other recommendations	32
34	Rebuttal Issue 10: AG-MN Witness Alvarez's unsupported technical presumptions..	33

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1	Part III - NWA: Adaptive Networked Microgrid	35
2	Rebuttal Issue 11: Staff Witness DeCooman recommends the full disallowance of the	
3	NWA: Adaptive Networked Microgrid project until the funding agreement is finalized.	
4		35
5	Part IV - Rebuttal Issue 12: General Rebuttal Points	36
6	Table 3 - General Rebuttal Issues	37
7		
8	<u>Part I - Distribution Automation</u>	
9	Q7. What are AG-MN Witness Stephens' recommendations regarding the	
10	Company's Distribution Automation program?	
11	A7. On page 41, lines 1-13, AG-MN Witness Stephens recommends the Commission	
12	should require the Company to deploy a benefit-cost model to govern Distribution	
13	Automation deployment on a circuit-specific basis. He further recommends on	
14	page 41, lines 14-19, that until a circuit-specific Distribution Automation model	
15	can be developed the Commission limit the Distribution Automation deployment	
16	budget to the annual amount the Commission approved in U-21297 (\$27.167	
17	million less a 10% reduction recommended by Staff in that case).	
18		
19	Q8. Why does Witness Stephens make these recommendations?	
20	A8. Witness Stephens provides a variety of reasons summarized below:	
21	1) DTE Electric provides no measurable safety basis to support investments.	
22	a) DTE Electric provides no measurable safety basis to support the investment	
23	request for Distribution Automation. ¹	
24	b) The wire down risk on DTE Electric's 4.8kv circuits has existed for 75-120	
25	years. ²	

¹ Stephens DT, p. 40, lines 6-9.

² Stephens DT, p. 40, lines 11-12.

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- 1 c) A 4.8kV automated switch cannot be used on a 13.2kV circuit and could
2 render money spent on 4.8kV circuits being converted in the next 15 years
3 largely wasted.³
- 4 2) Drawbacks of Automation
- 5 a) Automated switches may operate incorrectly.⁴
- 6 b) In storm situations, where damage is widespread, intact circuits from which
7 to reroute power may not be available, negating Distribution Automation
8 value.⁵
- 9 c) The switches are costly and in his experience he believes one tie line/switch
10 per circuit is typically optimum.⁶
- 11 d) Distribution Automation is most often cost-effective when tie lines between
12 circuits have already been built.⁷
- 13 e) Distribution Automation is a solution that addresses a symptom, not root
14 causes and is not a cure-all, and is only appropriate for some circuits.⁸
- 15 3) The Company's automation prioritization tool is not designed to quantify
16 benefits in dollars.
- 17 a) The Automation Prioritization tool is not designed to quantify benefits in
18 dollars, enabling a comparison to cost and a risk-informed, dollar-
19 denominated benefit-cost analysis is what is needed.⁹
- 20 b) The Distribution Automation circuit model should reflect all costs,
21 including the cost to construct tie-lines between circuits.¹⁰

³ Stephens DT, p. 40, lines 17-19.

⁴ Stephens DT, p. 38, lines 20-21.

⁵ Stephens DT, p. 38, lines 21-22.

⁶ Stephens DT, p. 39, lines 1-3.

⁷ Stephens DT, p. 39, lines 4-7.

⁸ Stephens DT, p. 39, lines 9-12.

⁹ Stephens DT, p. 39, lines 14-21.

¹⁰ Stephens DT, p. 41, 9-13.

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1 Rebuttal Issue 1: AG-MN Stephens' claim that DTE provides no measurable safety basis
2 to support investments is incorrect based upon the safety data provided

3 **Q9. How does Witness Stephens describe DTE Electric's Distribution Automation**
4 **Program?**

5 A9. Witness Stephens summarizes¹¹ the purpose and benefits of distribution
6 automation, when he states "Distribution Automation employs sophisticated
7 switches which automatically reconfigure the grid, avoiding time spent by
8 dispatchers (trying to figure out the best reconfiguration) and crew travel time (to
9 throw the switches). Distribution Automation can therefore reduce the duration of
10 service interruptions for some customers initially impacted by a fault. The
11 sophistication of the switches adds some value too; remote communication and
12 control are standard, and the switches incorporate line sensors for monitoring grid
13 status with precision (voltage, current, frequency, phase balance, etc.)."

14

15 **Q10. Do you agree with Witness Stephens summary of Distribution Automation**
16 **benefits?**

17 A10. Yes, although he does not mention all of the benefits of Distribution Automation.
18 In addition to improving reliability and shortening duration of outages, there are
19 safety benefits the sophisticated switches (i.e., reclosers) provide on the Company's
20 4.8kV delta system.

21

22 **Q11. What is Witness Stephens' claim regarding Automation safety benefits?**

23 A11. Witness Stephens claims that DTE Electric provides no measurable safety basis to
24 support the investment request for Distribution Automation.¹²

¹¹ Stephens DT, p. 38, lines 11-18.

¹² Stephens DT, p. 40, lines 6-9.

Line
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1 **Q12. Does the Company agree with Witness Stephen' claim that the Company has**
2 **not provided support for the measurable safety benefit of automation in the**
3 **4.8kV delta system?**

4 A12. No. As mentioned in my direct testimony,¹³ the Company has included a unique
5 consideration when deploying its Distribution Automation strategy due to the
6 nature of the ungrounded 4.8kV delta system. The Distribution Automation
7 program includes start of circuit reclosers on the 4.8kV circuits that provide new
8 capability to detect when a ground occurs on a circuit, as well as the ability to isolate
9 the grounded circuit. Having the start of circuit reclosers with the ground detection
10 capability allows the Company to quickly detect and mitigate potential safety
11 hazards due to energized downed wires through automated isolation. Without these
12 devices and the ground detection capability, field crews would need to patrol to
13 locate and mitigate the safety hazards of downed wires that could potentially remain
14 energized for a longer period of time.¹⁴

15

16 **Q13. Did the Company quantify the estimated safety benefits of Distribution**
17 **Automation?**

18 A13. Yes. On page SMH-15 lines 1-4 of my direct testimony, the Company states the
19 circuits being automated in 2025 see an average of 17 downed wires per year. With
20 the start of circuit recloser, these potentially energized downed wires would be
21 detected and isolated very quickly. Additionally, the Company submitted the
22 Distribution Automation Prioritization tool¹⁵ in discovery, as well as the list of

¹³ Hartwick DT, p. SMH-13, lines 12-21.

¹⁴ Hartwick DT, p. SMH 14, lines 4-25.

¹⁵ Ex. A-53, Sch. RR2

Line
No.

1 circuits planned for automation in 2025 in discovery response MNSCDE-7.1(c).¹⁶

2 The tool shows the historical wire downs associated with each specific circuit.

3

4 **Q14. Witness Stephens includes a statement that since the energized wire down risk**
5 **on DTE Electric's 4.8kv circuits have existed for the last 75-120 years and**
6 **automated switches have been available for more than a decade, DTE**
7 **Electric's sudden sense of urgency is unconvincing and warrants scrutiny.¹⁷**
8 **Does the Company agree that the current long lifespan of the 4.8kV circuits is**
9 **inconsistent with a sense of urgency to invest in this technology with known**
10 **safety benefits ?**

11 A14. No. While automated switches have been available for years, the ground detection
12 capability has recently been enabled by advancements in the logic algorithm
13 capability of the SEL651R relay, that is the G&W viper recloser controller. This
14 new logic algorithm, combined with the G&W Viper, is now able to derive safety
15 benefits in terms of ground detection, that were not previously available. The G&W
16 recloser with the SEL651R relay is now able to detect and isolate grounds on 4.8kv
17 circuits, mitigating potential safety hazards. The Company believes that improving
18 safety risk associated with potential energized downed wires is an important part of
19 the Distribution Automation program.

20

21 **Q15. What does Witness Stephens claim about the automated switches the**
22 **Company is using?**

23 A15. On page 40, lines 17-21, he appears to claim that the automated switches are voltage
24 specific when he says, "[a] 4.8kv switch cannot be used on a 13.2kv circuit".

¹⁶ Ex. A-53, Sch. RR1.

¹⁷ Stephens DT, p. 40, lines 11-14.

Line
No.

1 **Q16. Does the Company agree with this claim?**

2 A16. No. The Company has purchased and installed reclosers that are classified with
3 voltage capability of 15kV, which therefore can be used on both the 4.8kV and
4 13.2kV systems. Investments in reclosers today will be able to continue to be used
5 when circuits are converted from 4.8kV to 13.2kV.

6

7 Rebuttal Issue 2: AG-MN Stephens' claim that there are five Drawbacks of Automation

8 **Q17. What does Witness Stephens describe as the first drawback regarding**
9 **Distribution Automation?**

10 A17. He claims that automated switches may operate incorrectly, requiring crews to
11 drive from switch to switch anyway.¹⁸

12

13 **Q18. Does the Company Agree with Witness Stephens claim that Automated**
14 **switches may operate incorrectly?**

15 A18. While automated devices can have the remote possibility to operate incorrectly, the
16 G&W Viper is an industry proven and reliable device. DTE Electric follows a
17 robust process every time a new device is being evaluated to be approved for
18 deployment. In the case of the G&W Viper reclosers, this process included working
19 with Electric Power Research Institute (EPRI) to perform a thorough testing and
20 evaluation of the device,¹⁹ alongside with a live field installation and performance
21 evaluation before the device is formally approved to be used on the system.

22

¹⁸ Stephens DT, p. 38, lines 20-21.

¹⁹ EPRI. (2023, Oct 13). *Recloser Life-Cycle Management: G&W Viper ST 15kV Recloser*. EPRI.
<https://www.epri.com/research/products/000000003002027884>

Line
No.

1 **Q19. What does Witness Stephens describe as the second drawback regarding**
2 **Distribution Automation?**

3 A19. He claims that in storm situations, where system damage is widespread, intact
4 circuits from which to reroute power may not be available, negating Distribution
5 Automation value²⁰.

6
7 **Q20. Does the Company Agree that the benefits of distribution automation may not**
8 **apply to storm situations?**

9 A20. No. In fact, during storm situations, where damage may be widespread, reclosers
10 are well suited to automatically identify and isolate damaged areas without
11 intervention, thus enabling very fast restoration for portions of circuits, thereby
12 freeing crews up to perform other restoration jobs. The reclosers at the start of the
13 4.8kv circuits will detect and automatically isolate potentially energized downed
14 wires. The midpoint reclosers will operate when a fault is detected and isolate the
15 outage to a smaller area, impacting fewer customers. The reclosers at the tie points
16 provide the ability to remotely reconfigure circuits and reroute power around
17 damaged sections by connecting to adjacent circuits. Witness Stephens concern
18 was that these tie reclosers may not be able to operate during storms if the adjacent
19 circuit does not have power. In my direct testimony, SMH-15, lines 18-22, this
20 concern was addressed; the Company states their projected benefits of tie locations
21 were adjusted to account for catastrophic storm conditions during which adjacent
22 circuits may be impacted, thereby reducing the benefits. This condition was
23 addressed through a reduction to overall benefits of the Distribution Automation
24 Program, rather than on an individual circuit basis.

²⁰ Stephens DT, p. 38, lines 21-22.

Line
No.

1 **Q21. What does Witness Stephens describe as the third drawback regarding**
2 **Distribution Automation?**

3 A21. Witness Stephens claims the switches are costly, and in his experience, because of
4 the cost he believes that one tie line/switch per circuit is typically optimum. He
5 states he has observed investor-owned utilities install automatic switches beyond
6 the point of diminishing return.²¹

7
8 **Q22. Does the Company agree that one tie-line /recloser is optimal in all cases?**

9 A22. No. The Company's plan is to reduce the number of customers impacted by outages
10 and eliminate safety concerns due to potential energized downed wires. As
11 mentioned above, adding a recloser at the start of the 4.8kV circuits addresses safety
12 related issues due to potential energized wire down events. The optimal number of
13 devices installed on each circuit depends on the specific characteristics of each
14 unique circuit such as the circuit configuration, how many customers the circuit
15 serves, historical reliability performance of the circuit. The Company reviews each
16 circuit and performs an engineering review to determine the optimal number of
17 devices to install, specific to the characteristics of each circuit.

18
19 **Q23. What does Witness Stephens describe as the fourth drawback regarding**
20 **Distribution Automation?**

21 A23. Witness Stephens states that Distribution Automation is most often cost-effective
22 when tie lines between circuits have already been built,²² and care should be taken
23 to ensure tie lines are not being built where the benefits fail to outweigh the costs.

24

²¹ Stephens DT, p. 39, lines 1-3.

²² Stephens DT, p. 39, lines 4-7.

Line
No.

1 **Q24. Does the Company agree that Automation is most cost-effective when tie lines**
2 **between circuits have already been built?**

3 A24. While this statement made by Witness Stephens is not supported with specific data
4 or analysis for the Company to evaluate, the Company generally agrees that circuits
5 with established tie points are likely lower in cost to automate than a circuit where
6 a tie point has to be built. However, that does not imply that locations without an
7 established tie point are not cost-effective to automate. In addition, when
8 considering the full benefit-cost analysis, cost is not the only factor to consider,
9 benefits must also be considered. As mentioned in my direct testimony,²³
10 approximately 48% of the Company's distribution circuits already have established
11 tie points. "An additional 40% of the circuits either require some investment to
12 establish a tie point or require a detailed evaluation to determine if investment is
13 needed to increase emergency capacity needed to support service restoration."²⁴
14 The remaining 12% of circuits have physical restrictions making establishing tie
15 points difficult. In summary, the Company does not plan on building tie points on
16 every single circuit, but rather plans to evaluate each circuit individually to identify
17 if a tie point needs to be established and automated.

18

19 **Q25. What does Witness Stephens describe as the fifth drawback regarding**
20 **Distribution Automation?**

21 A25. Witness Stephens states that Distribution Automation is a solution that addresses a
22 symptom, not root causes and therefore is not a cure-all, and is only appropriate for
23 some circuits.²⁵

²³ Hartwick DT, p. SMH-15, lines 10-18.

²⁴ Hartwick DT, p. SMH-15, lines 12-15.

²⁵ Stephens DT, p. 39, lines 9-12.

Line
No.

1 **Q26. Does the Company agree with this statement?**

2 A26. The Company agrees that Distribution Automation is not a cure-all solution for all
3 grid problems, and additionally does not imply the program addresses root causes
4 of grid outages. Rather, the Distribution Automation program is designed to reduce
5 the number of customers impacted by an outage, shorten outage duration, and
6 mitigate potential safety hazards when there has been an outage on the system.

7

8 **Q27. Can you summarize the Company's support for the Distribution Automation**
9 **Program?**

10 A27. The Company's Distribution Automation program is designed to reduce the number
11 of customers impacted by an outage, shorten outage duration, and mitigate potential
12 safety risks on the 4.8kv system. The program was designed to address the unique
13 characteristics of the Company's distribution system. Distribution automation has
14 been proven to be an effective reliability improvement strategy that has been
15 utilized across the industry. As mentioned in my direct testimony, page SMH-11 to
16 SMH-12, the Distribution Automation technologies and Smart Grid Investment
17 Grant Projects discussed by the DOE in a 2016 report on the benefits of distribution
18 automation highlight five utilities who reported a 50-55% reduction in the number
19 of customer interruptions and customer minutes of interruptions per outage event
20 after deploying distribution automation. The estimated benefits from this program
21 are a significant part of the Company's plan to reduce customer interruptions and
22 restore customers faster when there has been an interruption. As stated in my direct
23 testimony, SMH-20, lines 3-10, the Company expects to reduce SAIDI on circuits
24 automated in 2025 by 47% and reduce system SAIDI by 45 minutes.

25

Line
No.

1 Rebuttal Issue 3: AG-MN Stephens' specific recommendation for a Distribution
2 Automation benefit-cost model, as opposed to the currently used prioritization tool
3 supporting Distribution Automation

4 **Q28. What does Witness Stephens recommend regarding a benefit-cost model?**

5 A28. Witness Stephens recommends the Commission should require the Company to
6 develop a benefit-cost model to govern Distribution Automation deployment on a
7 circuit-specific basis.²⁶

8

9 **Q29. How does Witness Stephens support his recommendation?**

10 A29. Witness Stephens does not explicitly state the reason for this recommendation,
11 although he provides details on what he believes should be in such a model. Earlier
12 in his testimony Witness Stephens describes many of the benefits of Distribution
13 Automation, including a reduction in service interruptions for customers²⁷. Based
14 on comments throughout his testimony, as I have discussed above, his concerns
15 appear to be mostly centered around ensuring the company deploys the program in
16 a cost-effective manner and believes a circuit-by-circuit benefit-cost model is
17 required to do so.

18

19 **Q30. Does the Company agree with Witness Stephens recommendation that DTE**
20 **Electric be required to develop a benefit-cost model to govern automation**
21 **deployment on a circuit-specific basis?**

22 A30. No. At this time the Company has a tool, the Distribution Automation Prioritization
23 tool, which was utilized to determine automation deployment for the test year. On

²⁶ Stephens DT, p. 41, lines 1-4.

²⁷ Stephens DT, p. 38, lines 11-18.

Line
No.

1 page 39, lines 14-18, Witness Stephens states that the Automation Prioritization
2 Tool is a step in the right direction, but that it does not quantify benefits in dollars.

3

4 **Q31. Can you please describe the Distribution Automation Prioritization tool?**

5 A31. The Distribution Automation Prioritization tool uses historical reliability and safety
6 data (wire downs), along with the unique topology of each circuit to determine the
7 projected reliability and safety benefits that Automation will provide for each
8 specific circuit. The tool assigns points to each circuit based on four key weighted
9 benefit criteria and divides the points by the estimated circuit investment dollars.
10 The circuits are then ranked by points per dollar, which the Company uses to
11 prioritize selection of circuits for Distribution Automation.

12

13 **Q32. Does this tool quantify the reliability and safety benefits of distribution**
14 **automation?**

15 A32. Yes. The tool projects the reliability and safety benefits from Distribution
16 Automation at a specific circuit level. The tool measures reliability in terms of
17 customer minutes of interruption, and safety benefits in number of potential live
18 wire downs avoided.

19

20 **Q33. Are these benefit projections utilized by the Company beyond**
21 **selecting/prioritizing circuits in the Distribution Automation program?**

22 A33. Yes. These benefit projections at a circuit specific level are inputs into the
23 Reliability model supported by Company Witness Kryscynski.

24

Line
No.

1 **Q34. What are the benefits of Distribution Automation projected by the Company**
2 **in the test year?**

3 A34. As stated in my direct testimony, pages SMH-15, lines 1-4 and SMH-20, lines 3-
4 10, based on the circuit specific model and circuits selected for 2025, the Company
5 expects to address ground detection and isolation for 149 4.8kv circuits, which see
6 an average of 17 downed wires per year, and is expected to reduce SAIDI on
7 impacted circuits by 47% reducing system SAIDI by 45 minutes.

8

9 **Q35. Can you provide any additional evidence that Distribution Automation has**
10 **measurable benefits?**

11 A35. Yes. The US Department of Energy (DOE), as part of the ARRA funding in 2008,
12 tracked the metrics of the equipment those grants provided, which included
13 distribution automation (DA) equipment. A DOE 2016 report titled “Distribution
14 Automation”²⁸ published the resulting improvements to metrics due to Distribution
15 Automation equipment investments. The DOE report, page 5, states “DA
16 technologies provided advanced capabilities for operators to detect, locate, and
17 diagnose faults. Fault location, isolation and service restoration (FLISR)
18 technologies can automate power restoration in seconds by automatically isolating
19 faults and switching some customers to adjacent feeders.” In a call out box on page
20 5, the DOE summarizes the impact of the \$7.9 billion in grants that deployed over
21 82,000 automation devices: “Per outage event, FLISR operations reduced number
22 of customers interrupted by 53% and reduced customer minutes of interruption by
23 53%”. Further, it goes on to state “[i]n 2013, 3 utilities reported System Average

²⁸DOE. (2016, Sep.). *Distribution Automation: Results from the Smart Grid Investment Grant Program*.
<https://www.energy.gov/sites/prod/files/2016/11/f34/Distribution%20Automation%20Summary%20Report%2009-29-16.pdf>

Line
No.

1 Interruption Frequency Index (SAIFI) improvements of 17 to 58% from pre-
2 deployment baselines.” The study goes on to point to a massive storm related
3 outage in Chattanooga, TN during a derecho weather event in July of 2012, where
4 FLISR “helped operators restore system-wide power about 17 hours earlier than
5 without DA.” In a second storm in Chattanooga, TN two years later, FLISR “was
6 able to restore power 36 hours faster and reduce affected customers from 70,000
7 down to 33,000.” As demonstrated in the DOE study, Distribution Automation
8 equipment investments improved reliability, in that less customers were affected
9 by outages and outages were shorter in duration.

10

11 **Q36. Does the Company plan to make enhancements to the Automation**
12 **Prioritization tool in the future?**

13 A36. Yes. The Company plans to make enhancements to the Automation Prioritization
14 tool as part of an overall company effort discussed by Witness Kryscynski to further
15 advance BCAs to enhance our already strong investment analysis.²⁹ The
16 Automation Prioritization tool has all the foundational data and components already
17 established that the company will build upon to work towards a broader BCA
18 framework. Any effort to create an entirely new BCA for Distribution Automation
19 would duplicate extensive effort already put forth to develop the Automation
20 Prioritization tool.

21

22 **Q37. Does the Company agree with Witness Stephens recommendation that until a**
23 **circuit-specific Distribution Automation model can be developed the**
24 **Commission should limit the Distribution Automation deployment budget to**

²⁹ See further discussion on the Company’s plan for BCA improvements in Kryscynski Rebuttal Testimony: Rebuttal Issue 5 “Benefit Cost Analysis”

Line
No.

1 **the annual amount the Commission approved in U-21297 (\$27.167 million less**
2 **a 10% reduction recommended by Staff)?**

3 A37. No. The Company's planned Distribution Automation investments provide clear
4 and compelling reliability and safety benefits to customers, as detailed above. The
5 entire automation program will take many years to implement and given that we
6 are in the very early stage of this automation journey, the prioritized initial
7 deployment is a clear no-regret investment that the company should aggressively
8 pursue. Furthermore, the Company's Distribution Automation Prioritization tool
9 prioritizes circuits based on benefits per dollar as detailed above. The benefits per
10 dollar were primarily considered in selecting which circuits to automate. This
11 current approach addresses circuits where Automation will provide the greatest
12 benefits to customers. Lastly, as mentioned above, the Company is working toward
13 a cost-benefit analysis.

14

15 **Part II - Grid Automation Telecommunications**

16

17 Rebuttal Issue 4: AG-MN Witness Stephens and Alvarez's recommendation to disallow
18 strategic capital associated with Grid Automation Telecommunications is inappropriate
19 due to prior approvals and support for 2024 and 2025 investments.

20 **Q38. What is AG-MN Witness Stephens' recommendation regarding Grid**
21 **Automation Telecommunications investments?**

22 A38. In the table on page 46 of his direct testimony, as well as in his unmarked Exhibit
23 MEC-11, Witness Stephens recommends a disallowance of \$16,900,000 for the
24 Bridge Period ending December 31, 2024, and \$15,000,000 for the Test Year, 12
25 months ending December 31, 2025.

Line
No.

1 **Q39. Does AG-MN Witness Stephens’ provide any other discussion of the proposed**
2 **disallowance for Grid Automation Telecommunications?**

3 A39. Witness Stephens’ only support is Witness Alvarez’s testimony. Witness Stephens
4 does not provide any additional support of his own.

5

6 **Q40. What is AG-MN Witness Alvarez’s recommendation regarding Grid**
7 **Automation Telecommunications investments?**

8 A40. On page 64, lines 1-2, of his direct testimony, Witness Alvarez recommends “that
9 the Commission disallow Telecommunications Plan costs incurred in 2022 and
10 remove Plan spending from the 2023-2024 bridge period and 2025 test year.”

11

12 **Q41. Is AG-MN Witness Alvarez’s recommendation regarding disallowance of Grid**
13 **Automation Telecommunications investments consistent with AG-MN**
14 **Witness Stephens?**

15 A41. No, Witness Stephens only proposes disallowance for 2024 of the bridge and test
16 year, while Witness Alvarez proposes disallowance of all Grid Automation
17 Telecommunications incurred to date.

18

19 **Q42. Does AG-MN Witness Alvarez’s provide any support or explanation for his**
20 **broader disallowance including historical investments?**

21 A42. No. There is no additional explanation or rationale provided and no exhibit or table
22 detailing this is provided.

23

24 **Q43. What is the purpose and necessity of telecommunications in supporting the**
25 **more safe, reliable grid of the future?**

Line
No.

1 A43. As described in my testimony,³⁰ the telecommunications network is the backbone
2 system that connects the distribution automation equipment in the field to the
3 System Operations Center (SOC). The network enables two-way communication
4 that provides visibility into grid conditions and SOC the ability to remotely operate
5 grid devices. An advanced telecommunications infrastructure plays a crucial role
6 in grid automation by providing reliable and secure communication channels for
7 data exchange between various grid devices such as sensors, meters, switches, and
8 control centers. These secure and reliable data exchanges enable programs like
9 Distribution Automation, Conservation Voltage Reduction (CVR), Volt-Var
10 Optimization (VVO), Advanced Metering Infrastructure, demand response, along
11 with other core components and advanced applications described in the Distribution
12 Grid Plan (DGP).³¹

13

14 **Q44. Have Grid Automation Telecommunications investments been approved by**
15 **the Commission in prior cases?**

16 A44. Yes. The December 1, 2023 order in U-21297 on page 121, “[t]he Commission
17 finds the ALJ’s recommendation to fund the bridge period but not the test year to
18 be well-reasoned and supported by the record and adopts the ALJ’s findings and
19 conclusion on this issue”. In Case No. U-21297, the Commission approved
20 \$14,206,000 for the 12 months ending December 31, 2022, and \$17,508,000 for the
21 11 months ending November 30, 2023. Since these investments have been approved
22 in the past, these investments are not being requested in the instant case and
23 therefore should not be retroactively disallowed.

24

³⁰ Hartwick DT, p. SMH-21 and SMH-24 through 26.

³¹ Kryscynski Exhibit A-23, Sch. M8

Line
No.

1 **Q45. What investments are being requested in the instant case?**

2 A45. In the instant case, the Company is requesting \$35,738,000 of investment beyond
3 prior rate case approvals to continue investments in this vital part of building the
4 grid of the future. In Table 1 below, the amount requested in the instant case,
5 column (d), is the Grid Automation Telecommunications Investments in column
6 (c) less the amount approved in Case No. U-21297 in column (b).

7

8 **Table 1 - Grid Automation Telecommunications Request (000s)**

(a)	(b)	(c)	(d) = (c) - (b)
Period	Approved in U-21297	Investment in U-21534	Request in U-21534
11 mos. Ending Nov 30, 2023	17,508	19,770	2,262
Dec 2023	0	1,576	1,576
2024	0	16,900	16,900
2025	N/A	15,000	15,000
Total	17,508	53,246	35,738

9

10 **Q46. What reasons does AG-MN Witness Alvarez offer to support his**
11 **recommended Grid Automation Telecommunication disallowance?**

12 A46. Witness Alvarez states three reasons for his recommendation on page 64, lines 3-7
13 of his direct testimony: “1) That DTE has not developed a benefit-cost or make vs.
14 buy analysis that supports its spending or Plan; 2) That the Company has not
15 complied with the Commission’s Order to analyze alternatives to its Plan; and 3)
16 That DTE refused to provide the Plan, of which the historical and proposed
17 spending in its Application constitute a foundational part”.

18

Line
No.

1 Rebuttal Issue 6: AG-MN Witness Alvarez states “DTE refused to provide the [Grid
2 Automation Telecommunication] Plan” despite the Company providing details for our
3 2024 and 2025 investments.

4 **Q47. What does AG-MN Witness Alvarez conclude about the overall Grid**
5 **Automation Telecommunication plan?**

6 A47. Witness Alvarez concludes that the 2025 investments cannot be evaluated without
7 understanding the entire plan.³²

8

9 **Q48. Does the Company agree with AG-MN Witness Alvarez in his conclusion?**

10 A48. No. The clear distinction between investments in the instant case and those that are
11 planned for beyond 2025 has been stated in both testimony³³ and discovery³⁴. The
12 investments in this case have definitive purpose to connect critical sites such as
13 generation sites, subtransmission stations, substations, service centers and
14 communications towers, with high-speed, high-bandwidth, and reliable connection.
15 Witness Alvarez ignores any inherent benefit in providing connectivity to critical
16 sites and fails to acknowledge there are current benefits from fiber standalone
17 investments, such as optionality and flexibility for the future. For the investments
18 beyond 2025, the telecommunications plan will shift focus and scope of
19 investments to remaining substations and last mile investments that will be
20 presented in the 2025 DGP and the next rate case.

21

³² Alvarez DT, p. 59 lines 15-17 and p.60 lines 1-2

³³ Hartwick DT, p. SMH-27, lines 15-21

³⁴ Alvarez Ex MEC-8, Company response to MNSCDE-7.4(c)

Line
No.

1 **Q49. What is the AG-MN Witness Alvarez’s first concern made regarding the scope**
2 **of future Telecommunications Investments of DTE Electric’s Grid**
3 **Automation Telecommunications Plan?**

4 A49. Witness Alvarez states on page 59 of his direct testimony, lines 11-12, that “[t]he
5 Company refused to provide details for the plan beyond 2025, citing that details for
6 the Plan beyond 2025 are beyond the scope of the Company’s application.”

7
8 **Q50. Does this statement accurately reflect what the Company has provided in the**
9 **instant case?**

10 A50. No. While the Company did state in discovery response MNSCDE-7.4(b), which
11 is provided in Witness Alvarez’s Exhibit MEC-8, that the “deployments in 2026
12 and beyond are outside of the instant case”. The Company provided a list of our
13 2024 and 2025 fiber deployments by route and identified the substations associated
14 with each route.

15
16 The absence of exact routes to be deployed beyond 2025 does not warrant
17 disallowance in the instant case, as they are distinct from the instant case
18 investments to connect critical distribution sites. However, the absence of the exact
19 routes beyond 2025 can be understood as explained in my direct testimony on page
20 SMH-27, lines 19-20, the plan beyond the instant case “will continue to expand the
21 telecommunication network to the next tier of locations that are prioritized from a
22 resiliency perspective.” Page SMH-48, lines 1-3 of my testimony also explains that
23 “[i]n 2026 and through the end of the program, fiber routes will run through a cost
24 benefit analysis to support the selection of the appropriate future technology to be
25 used.” Both sentiments were reiterated in the Company’s MNSCDE-7.4(c)

Line
No.

1 discover response, provided in Witness Alvarez's Exhibit MEC-8, along with the
2 acknowledgement that the tool for determining deployments beyond 2025 is not yet
3 complete.

4

5 **Q51. What is AG-MN Witness Alvarez's second concern regarding the scope of**
6 **future Telecommunications Investments of DTE Electric's Grid Automation**
7 **Telecommunications Plan?**

8 A51. Witness Alvarez states on page 59, lines 12-14, of his direct testimony that "[t]he
9 Company's 2023 Distribution Grid Plan³⁵ provides no additional information on
10 the Telecommunications Plan."

11

12 **Q52. Does the 2023 Distribution Grid Plan have information on Grid Automation**
13 **Telecommunications?**

14 A52. The Company's 2023 Distribution Grid Plan (DGP) does in fact provide additional
15 information on the Telecommunications Plan. A graphical overview of DTE
16 Electric's Future Network Technology Landscape is presented in DGP Exhibit
17 10.1.5.2 on page 141 of Exhibit A-23, Schedule M8 (sponsored by Company
18 Witness Kryscynski) along with a general summary work between 2024 and 2028.
19 Additionally, projected yearly investments from 2024 through 2028 is provided in
20 Exhibit 10.1.3 on page 137 of Exhibit A-23, Schedule M8. It is worth noting that
21 Witness Alvarez's statement about the cost of the telecommunications plan
22 referenced Exhibit A-23, Schedule M8, page 137 in his summary of the plan.³⁶

23

³⁵ Kryscynski Ex. A-23, Sch. M8

³⁶ Alvarez DT, p. 58, line 18.

Line
No.

1 **Q53. Has the Company provided the overall plan for Telecommunications and**
2 **appropriate support for the requested Telecommunications investments that**
3 **are included instant case?**

4 A53. Yes. For clarity I will provide a brief overview here. The general
5 Telecommunications plan scope as stated in the DGP, Exhibit A-23, Schedule M8,
6 page 142-143, is as follows: “Between 2024 and 2028 fiber routers will be installed
7 to complete fiber loops and provide communications to end points. This work will
8 include installing communication poles, fiber entrances and taps along installed
9 routes to make final connections into substations and support the advanced mesh
10 network deployment with additional mesh nodes.”

11

12 Testimony, pages SMH-25 through SMH-28, segregates the plan into three general
13 phases. (1) Installation and commissioning of the fiber backbone to critical sites
14 will continue through 2025. (2) Investments in 2026 through 2028 will focus on
15 extending of the backhaul network to next tier locations that cannot be sufficiently
16 served by existing deployed technologies or currently do not have communications
17 capabilities. (3) Finally, future investments beyond 2028 in grid
18 telecommunications will focus on building out the last mile network to pole top
19 devices.

20

21 For the instant case, the first phase, the installation of the backbone to critical sites,
22 will run through the end of the test year—2025. A listing of more detailed work
23 scope planned and installed between 2022 and 2025 is listed on pages SMH-42
24 through SMH-45. Additionally, exact routes were provided in MNSCDE-7.4(b),
25 presented in Witness Alvarez’s Exhibit MEC-8, for 2024 and 2025.

Line
No.

1 Rebuttal Issue 7: AG-MN Witness Alvarez’s opinion that the Alternative Analysis
2 provided in the instant case failed to meet the Commission’s previous request is incorrect
3 based upon the record.

4 **Q54. What did the Commission order the Company to do in U-21297 in regard to**
5 **analysis supporting Grid Automation Telecommunications?**

6 A54. The Commission ordered DTE Electric to analyze a variety of alternatives before
7 advancing its Grid Automaton Telecommunications Plan further by agreeing with
8 the ALJ’s recommendation, affirming “[the ALJ] further found that the company
9 should be required to provide an analysis of alternatives when requesting further
10 extensions of the fiber network.”³⁷

11

12 **Q55. Did the Company comply with the Commission’s order to provide an analysis**
13 **of alternatives to support the continued investments in the backhaul fiber**
14 **network?”**

15 A55. Yes. As provided in my direct testimony, pages SMH-29 to SMH-42, I presented
16 an assessment of communication alternatives for the backhaul network investments
17 through 2025. The assessment evaluates Public Cellular, Private Long-Term
18 Evolution (LTE) Cellular, Point-to-Multipoint and Point-to-Point Microwave,
19 Wireless Mesh, Leased fiber, and Company-owned (i.e., “Private”) fiber options.
20 As part of the assessment, there is a description of each technology, the Company’s
21 current level of utilization, and key considerations in evaluating cost considerations
22 as well as the benefits of each technology.

23

³⁷ December 1, 2023 Order in U-21297. p. 119-122

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1 The alternatives were compared through the lens of reliability, life cycle factors,
2 and initial cost factors in Figures 3-5 of my testimony. This evaluation of the
3 different options and ranking was based on the expertise of a group of subject
4 matter experts with a combined experience of over 50 years in telecommunication
5 domain expertise.

6

7 **Q56. What feedback does AG-MN Witness Alvarez provide in his testimony on the**
8 **analysis methodology, options and ranking of factors in the**
9 **Telecommunications Alternative Analysis?**

10 A56. Witness Alvarez did not provide feedback on the options or ranking of factors. His
11 opinion on the analysis methodology is that it is not “remotely adequate”³⁸.

12

13 **Q57. Why is the alternative analysis the appropriate tool to evaluate the expansion**
14 **of the backhaul network through 2025?**

15 A57. The investments through 2025 are supporting communications from our Electric
16 System Operations Center and Alternative System Operations Center to our sub
17 transmission and distribution stations, service centers, communication towers and
18 generation sites throughout the service area. The appropriate question to ask for
19 these investments is “What technology meets the requirements to have secure and
20 reliable communications?”

21

22 The primary factors considered were the ability of the technology to fully serve the
23 bandwidth (amount of data) and latency (delay in transmitting data) needs, and the
24 reliability and the essential cybersecurity characteristics of those systems for
25 providing service to critical sites and infrastructure.

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1 **Q58. How was reliability evaluated in the alternative analysis?**

2 A58. For the technologies, the reliability is shown in Figure 3 of my testimony.³⁸

3 Reliability was evaluated based upon Bandwidth, Low Latency, Network Control,

4 Prioritization and Quality of Service, Security, Maintenance Window Scheduling,

5 Disaster Recovery, Control of Communications During Emergency and Protection

6 Against Interference and FCC Decisions.

7

8 **Q59. How were life cycle costs considered in the alternative analysis?**

9 A59. As shown in Figure 4 of my testimony,³⁹ life cycle factors were ranked in the
10 alternative analysis. Various technologies are compared across Ongoing Operating

11 Costs (Excluding Staffing), Staffing, Open Standards, Technology Availability,

12 Technology Stability and Technology Lifespan.

13

14 **Q60. Were initial costs considered in the alternative analysis?**

15 A60. Yes. In Figure 5,⁴⁰ the initial costs of the technologies were compared across

16 Control of Geography Covered, Device Deployment Effort and Installation Cost.

17

18 **Q61. Which investments are supported by the alternative analysis?**

19 A61. The technology alternative analysis shown in Figures 3-5 of my direct testimony,
20 page SMH-39 to SMH-40, supports the use of Company-owned fiber for the

21 backhaul network to connect critical assets. The associated investment in the

22 current case is \$35.7 million.

23

³⁸ Hartwick DT, p. 39, Figure 3.

³⁹ Hartwick DT, p. SMH-40, Figure 4.

⁴⁰ Hartwick DT, p. SMH-40, Figure 5.

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1 Rebuttal Issue 8: AG-MN Witness Alvarez’s recommendation for Benefit-Cost or Make
2 vs. Buy Analysis is inappropriate for investments within the test year

3 **Q62. What is AG-MN Witness Alvarez’s final reason for the Grid Automation**
4 **Telecommunication disallowance?**

5 A62. Witness Alvarez’s final reason is “DTE has not developed a benefit-cost or make
6 vs. buy analysis that supports its spending or Plan”⁴¹

7
8 **Q63. What does AG-MN Witness Alvarez recommend a make vs. buy study**
9 **include?**

10 A63. In his testimony, he explains of a comprehensive make vs. buy study would
11 “compare the pros and cons of each technology on technical, operational,
12 cybersecurity, reliability, and other characteristics, and compare these pros and
13 cons to the risks associated with each technology (generally, the size of the up-front
14 investment) and the cost of each technology not just initially, but over the lifetimes
15 of each alternative’s operation”⁴²

16
17 **Q64. Has DTE Electric provided the make vs. buy study characteristics AG-MN**
18 **Witness Alvarez suggests in the instant case?**

19 A64. Yes. As shown in the table below, DTE Electric has provide qualitative
20 characteristics of a comprehensive make vs. buy analysis to support investments in
21 the instant case.

22

⁴¹ Alvarez DT, p. 64, lines 3-4.

⁴² Alvarez DT, p. 62, lines 7-11.

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1

Table 2 - Make vs. Buy Characteristics

Characteristics Evaluated	Inclusion in U-21534
Pros and cons of technical characteristics	Summary of the uses and characteristics of each telecommunication system type from page SMH-30 to SMH-36
Pros and cons of Operational characteristics	Summary of the uses and characteristics of each telecommunication system type from page SMH-30 to SMH-36
Pros and cons of Cybersecurity characteristics	Summary of the uses and characteristics of each telecommunication system type from page SMH-30 to SMH-36
Pros and cons of Reliability characteristics	Figure 3 on page SMH-39 and Exhibit A-19 Schedule I1.1
Risks	Summary of the uses and characteristics of each telecommunication system type from page SMH-30 to SMH-36
Initial Cost	Figure 5 on page SMH-40
Lifetime Cost	Figure 4 on page SMH-40

2

3 **Q65. Has the Company committed to developing a cost benefit analysis for the next**
4 **phase of the Telecommunications program?**

5 A65. Yes. My direct testimony, page SMH-48, lines 1-4 states “[i]n 2026 and through
6 the end of the program, fiber routes will be analyzed using a cost benefit analysis
7 to evaluate future technology alternatives to support the essential
8 telecommunications needs of all other DTE Electric investments and programs.”

9

10 **Q66. What is the Company’s journey in developing BCAs?**

11 A66. As discussed by Witness Kryscynski, the Company developed a new BCA
12 methodology for two investment areas, PTMM and undergrounding, and provided
13 these BCA spreadsheets and calculations as part of the case. The company intends
14 to move in the direction of conducting more BCAs to enhance our already strong

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1 investment analysis provided in the Global Prioritization Model and Reliability
2 Model.⁴³

3

4 **Q67. Has the Company continued its efforts to develop a BCA for Grid Automation**
5 **Telecommunications after the filing the instant case?**

6 A67. Yes. The Company is currently developing the cost benefit analysis tool for
7 determining fiber deployments beyond 2025, but it has not yet been completed.

8

9 **Q68. What level of precision is AG-MN Witness Alvarez seeking in either a “make**
10 **vs. buy” or benefit cost analysis?**

11 A68. In Witness Alvarez’s testimony, he states “Assessments of the characteristics of
12 various alternatives should also be supported by data. For example, it would not be
13 enough for DTE Electric to claim that a public carrier’s service is insufficiently
14 reliable; DTE Electric must identify the frequency with which commands issued
15 over DTE Electric’s owned network failed compared to the frequency at which
16 commands issued through the public carrier’s network failed.”⁴⁴

17

18 And that “DTE should provide the consequence of the difference to customers. For
19 example, of the increased failure rate observed (hypothetically) in commands
20 issued over a public carrier network how many resulted in service interruptions to
21 customers, and what were the consequences to customers (in dollars) of these
22 service interruptions?”⁴⁵

23

⁴³ See further discussion on the Company’s plan for BCA improvements in Kryscynski Rebuttal
Testimony: Rebuttal Issue 5 “Benefit Cost Analysis”

⁴⁴ Alvarez DT, p. 62 lines 14-18

⁴⁵ Alvarez DT, p. 62 line 19 – p.63 line 3

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1 **Q69. Is it practicable to meet this level of precision in identifying the most**
2 **appropriate communications solution given a variety of situations and**
3 **circumstances?**

4 A69. No. Witness Alvarez's proposed method would likely require the construction and
5 operation of parallel utility owned and third-party telecommunication systems. To
6 adequately compare the technologies, they would need to operate under similar
7 circumstances. The actual performance data would need to be recorded over enough
8 time to be statistically significant.

9
10 Witness Alvarez further indicates that the Company should develop a tool to derive
11 the appropriate solution for each circumstance from this data⁴⁶. To accurately
12 develop a tool which uses both utility and third-party data for the six technologies
13 compared in Figures 3-5 of my testimony,⁴⁷ results in twelve models for each
14 operating circumstance. Such a model would be complex to maintain and operate.
15 Even Witness Alvarez concedes that "DTE ... does not possess the data needed to
16 inform the development of such a tool."⁴⁸

17
18 **Q70. Should the Commission accept Witnesses Alvarez's and Stephens's**
19 **recommended disallowances for the Grid Automation Telecommunications?**

20 A70. No. First, the Company provided details of our Grid Automation
21 Telecommunications in my direct testimony, discovery and in the Distribution Grid
22 Plan. Second, the Company complied with the Commission's request for an
23 alternative analysis, which includes the characteristics endorsed by Witness

⁴⁶ Alvarez DT, p. 63, lines 6-11

⁴⁷ Hartwick DT, p. SMH-39-40, Figures 3-5.

⁴⁸ Alvarez DT, p. 63, lines 11-12

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1 Stephens. Third, the Company is committed to furthering our analysis of future
2 telecommunications by submitting a benefit cost analysis in our next rate case.

3

4 Rebuttal Issue 9: AG-MN Witness Alvarez's other recommendations

5 **Q71. Does Witness Alvarez provide any additional recommendations regarding**
6 **Grid Automation Telecommunications?**

7 A71. Yes. Witness Alvarez provides two additional recommendations.

8 1. I further recommend that the Commission order the Company to solicit an
9 independent expert to complete a comprehensive analysis of technical,
10 operational, cybersecurity, and reliability pros and cons of various
11 telecommunications options, and to compare these options to the risk and total
12 lifecycle costs associated with each option;⁴⁹

13 2. I further recommend that the Commission order the Company to complete a
14 tool that appropriately identifies the best alternative to employ in various
15 situations and circumstances.⁵⁰

16

17 **Q72. Does the company agree with Witness Alvarez's two additional**
18 **recommendations?**

19 A72. No. In Witness Alvarez's testimony he recommends four different analyses be
20 performed:

- 21 1. Benefit Cost Analysis;
22 2. Make vs. Buy Analysis;
23 3. A comprehensive analysis by an independent expert;
24 4. A tool to identify the best alternative.

⁴⁹ Alvarez DT, p. 64, lines 8-11.

⁵⁰ Alvarez DT, p. 64, lines 11-14.

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1 The Company does not believe all four analyses are required at this time and are
2 redundant of each other. In the instant case, the Company provided a comparative
3 analysis of alternative technologies on pages SMH-29 through SMH-42 of my
4 testimony for use connecting critical distribution sites pursuant to the
5 Commission's order in Case No. U-21297 on December 1, 2023. Additionally, the
6 Company is committed to developing a benefit cost analysis for determining
7 deployments beyond 2025, as stated in my direct testimony on page SMH-48, lines
8 1-4. The tool is not yet completed and was acknowledged in MNSCDE-7.4(c),
9 presented in Witness Alvarez's Exhibit MEC-8.

10

11 Rebuttal Issue 10: AG-MN Witness Alvarez's unsupported technical presumptions

12 **Q73. Does AG-MN Witness Alvarez claim DTE Electric has presumptions related**
13 **to Telecommunications that are not supported?**

14 A73. Yes. In reviewing the Company's Telecommunications Plan/projects, Witness
15 Alvarez states "[t]he Company makes two critical presumptions in support of its
16 Plan. These include: 1) that many new technologies require real-time
17 communications; and 2) of all available options, Company-owned options provide
18 the best combination of speed, control, security, and reliability."⁵¹

19

20 **Q74. Are real-time communications required to operate the technologies in a**
21 **modern grid?**

22 A74. Yes. In technology applications, the delay before a transfer of data begins is a
23 measurable term called "latency." Distribution Automation applications have strict
24 latency requirements, with most SCADA devices requiring a latency lower than

⁵¹ Alvarez DT, p. 60, lines 5-8

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1 200ms. For a backhaul network, a latency <50ms is required.⁵² These real-time
2 communications are required to provide device responses to remote commands,
3 supply the precise timing needed for protection schemes to ensure the grid is
4 operating within tolerances, and execute the automatic operation of devices. ADMS
5 control schemes perform real-time calculations, and any delays in field data used
6 in the control schemes can cause model simulation results to become invalid and
7 desynchronized. These and more use cases in the modern grid, as described in the
8 DGP⁵³, require low latency.

9

10 **Q75. Did the Company presume Company-owned options provide the best**
11 **combination of attributes as AG-MN Witness Alvarez stated?**

12 A75. No. Various technologies were evaluated as I describe in my testimony on pages
13 SMH-29 through SMH-42 for connecting critical distribution sites as part of the
14 backhaul network. There are benefits to Company-owned systems that I will briefly
15 describe here. In terms of security, a company-controlled network provides the
16 ability to tailor the security to the specific application. The flexibility that Witness
17 Alvarez implies⁵⁴ third-party systems may offer by being able to be procured as
18 needed is significantly limited by their technical implementation and commercial
19 terms, as well as the geographic range and quality of coverage and is not a good fit
20 for use cases where the duration of use will likely be multiple decades. Third-party
21 networks introduce complexity because a demarcation point where the third-party
22 system connects to the Company's distribution system must be set up, and the

⁵² Kuzlu, Murat & Pipattanasomporn, Manisa. (2013). Assessment of communication technologies and network requirements for different smart grid applications. Innovative Smart Grid Technologies (ISGT), 2013 IEEE PES. 1-6. 10.1109/ISGT.2013.6497873.

⁵³ Kryscynski Exhibit A-23, Schedule M8

⁵⁴ Alvarez DT, p.61, lines 7-8

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1 uncertainty in routing and troubleshooting due to proprietary systems can
2 complicate both the setup and operations. Long term costs are also a consideration
3 in third-party technologies. Third-party systems typically have a cost-of-service
4 model that includes high bandwidth usage over long periods of time accruing
5 significant costs that are subject to price increases and terms of service changes.
6 The Company has experienced challenges with the reliability of third-party systems
7 both in day-to-day performance variation, unnotified and unscheduled maintenance
8 windows and sporadic drops outs as well as major regional outages of carrier
9 systems. I've included details in Exhibit A-19, Schedule I1.1. The Company has
10 also been required to make unexpected investments due to third-party business
11 decisions, such as when a public carrier forced DTE Electric to invest \$36 million
12 to remediate and install new equipment to replace working assets.

13

14 **Part III - NWA: Adaptive Networked Microgrid**

15 Rebuttal Issue 11: Staff Witness DeCooman recommends the full disallowance of the
16 NWA: Adaptive Networked Microgrid project until the funding agreement is finalized.

17

18 **Q76. What is Witness DeCooman's recommendation for the NWA: Adaptive**
19 **Networked Microgrid project?**

20 A76. On page 21, lines 10-20 of testimony, Witness DeCooman states "Staff
21 recommends a full disallowance of all requested capital expenditures for the
22 [Adaptive Networked Microgrid] pilot, totaling \$4,588,307 and \$25,550,184 in the
23 bridge and test years, respectively. Staff is also recommending the corresponding
24 partner contributions and grant funding which offset a portion of these costs be
25 credited, to ensure this pilot has no impact on the revenue requirement, totaling

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1 \$2,608,544 and \$13,109,827 in the bridge and test years, respectively. While Staff
2 is generally supportive of this pilot and the value that it could provide the Company
3 through the development and operation of adaptive microgrids, Staff does not find
4 it appropriate to include this pilot in rates when the status of the Company's grant
5 application is uncertain, particularly given the Company's indication it would likely
6 not proceed with this project if this grant funding is not approved."

7

8 **Q77. How does the Company respond to Witness DeCooman's recommendation?**

9 A77. The Company appreciates the Staff's support and interest in the Adaptive
10 Networked Microgrid project. The Company will continue working diligently with
11 the Department of Energy to reach a funding agreement to legally secure the grant
12 funding and commence engineering and design. Since the as-filed in-service date
13 of the project is 2027, the disallowance of NWA: Adaptive Networked Microgrid
14 does not impact the revenue requirement.

15

16 **Part IV - Rebuttal Issue 12: General Rebuttal Points**

17 **Q78. Have any intervenors requested that the MPSC direct the Company to**
18 **undertake any specific activities related to distribution infrastructure or**
19 **processes?**

20 A78. Yes, intervenors have suggested a collection of conceptual proposals that they wish
21 the Commission to order the Company to undertake and they are listed in the table
22 below. However, as a group these suggested directives are undefined and largely
23 lack the detail requisite to even be thoroughly considered. The time, resources,
24 costs, and other inputs necessary to even begin these tasks have neither been
25 discussed nor even listed; the resultant values have not been calculated nor

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1 considered; alternatives have not been identified nor compared. In an attempt at
2 brevity the Company is not rebutting all the unsupported and misguided
3 suggestions individually, all of these requested directives should be denied.

4

5

Table 3 - General Rebuttal Issues

Witness	Rebuttal Point	Rebuttal
ABATE – York	Regarding distribution capital strategic replacements, on page 31, lines 6-11 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. ”	Page 70 of Company Witness Uzenski’s direct testimony, lines 19-25 (Q&A 135) states that for capital expenditures on projects that will not be in service during the projected test period do not have a current revenue requirement. Additionally, the Commission found Witness York’s similar proposed adjustments in case No. U-21297 unpersuasive by stating 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.” ⁵⁵ The Company recommends the Commission disregard Witness York’s recommendation in the instant case.

6

7 **Q79. Does this conclude your rebuttal testimony?**

8 A79. Yes, it does.

⁵⁵ Page 84 of Commission Order issued in Case No. U-21297 and dated December 1, 2023

1 JUDGE WALLACE: And then we will admit
2 all the exhibits at the close of cross. Is there any
3 objection, though, at this point to any of the schedules
4 that Ms. Hartwick is sponsoring? (No response.)

5 All right. We'll admit those at the end
6 of cross.

7 Mr. Bzdok, please go right ahead.

8 MR. BZDOK: Thank you, your Honor.

9 CROSS-EXAMINATION

10 BY MR. BZDOK:

11 Q Good morning, Ms. Hartwick.

12 A Good morning.

13 Q I have a few questions for you today unsurprisingly about
14 distribution automation. You sponsor for DTE Electric
15 Company the projected distribution automation spending in
16 this case; is that right?

17 A Yes.

18 Q That is -- your position, current position is Director of
19 Automation; is that right?

20 A Could you -- I'm sorry, somebody's off mute. Could you
21 repeat that question?

22 Q Sure. Your current position is Director of Automation,
23 correct?

24 A No.

25 Q Has it changed since your filing of your direct, your
Penn Reporting, LLC - lori.penn@yahoo.com

1 revised direct testimony?

2 A Yes.

3 Q What is your position now?

4 A Director of Conversion.

5 Q O.K. When did you change positions?

6 A Approximately three months ago.

7 Q O.K. You are still offering the Company's proposals and
8 spending projections and rationale for automation in this
9 case; is that right?

10 A Yes.

11 Q And is that basically -- is that based on essentially
12 your past experience in working on those programs?

13 A Could you rephrase the question, I didn't quite
14 understand?

15 Q Sure. Let me try it a different way. So when you
16 switched out of being Director of Automation to becoming
17 Director of Conversions, the Company did not refile your
18 testimony under the name of the new Director of
19 Automation; is that right?

20 A That is correct.

21 Q And why was that?

22 A I'm not sure I understand the question, could you
23 rephrase it?

24 Q Sure. You were up until three months ago essentially a
25 project lead or point person for DTE Electric Company in

1 the area of automation of various types in the
2 distribution system; is that fair?

3 A Yes.

4 Q And in spite of leaving that position three months ago,
5 you still have current knowledge and experience to be
6 able to offer testimony and facts related to those
7 programs?

8 A Yes.

9 Q O.K. Your leaving the position was not something I
10 anticipated, so I just needed to make sure we understood
11 exactly where we stand on that.

12 So up until three months ago, you were
13 more or less the person responsible for planning and
14 spending relative to distribution automation, among other
15 things; is that right?

16 A I wouldn't characterize it that way.

17 Q How would you characterize it?

18 A I was the director in the project management office
19 responsible for executing the automation program.

20 Q O.K. Thanks for that clarification. So I want to just
21 make sure I understand the three categories. You were
22 until three months ago the Director of Automation, there
23 is also reference in your testimony and exhibits to
24 distribution automation, there is also reference in
25 testimony and exhibits to grid automation; is that fair?

1 A Yes.

2 Q Can you explain to me what the then diagram looks like
3 for those, what's automation versus what's distribution
4 automation and what's grid automation?

5 A Grid automation is the broad category of all automation
6 on the grid; that includes, as structured in my direct
7 testimony, distribution automation, grid
8 telecommunication, CRV/VVO, and other items that I did
9 not mention. Distribution automation is a program that
10 is a subset of grid automation focused on automating the
11 distribution grid, primarily through devices such as
12 reclosers.

13 Q Thank you. I am sometimes taking notes over here on what
14 you say, I'm not doing other work while you're talking,
15 but so sometimes I'll have to catch up with you for a
16 moment.

17 So you said grid automation is the broad
18 category of all automation on the grid, you said it
19 includes distribution automation, grid
20 telecommunications; what else was on the list?

21 A I do not remember everything I mentioned, but I would
22 say, again, CRV/VVO, and other programs as listed in my
23 direct testimony.

24 Q Thank you. Bear with me a second. Capacitor replace --
25 sorry. Capacitor placement and control would be

1 included?

2 A Under the CRV/VVO program, yes.

3 Q NWAs?

4 A Yes.

5 Q Which, for the transcript, non-wires alternatives? For
6 the transcript, would you agree NWAs are non-wires
7 alternatives?

8 A Yes.

9 Q And are those a subset of one of the categories you
10 listed, or are they their own sort of subprogram?

11 A In my testimony, they are structured under the
12 distribution automation section -- excuse me. In my
13 testimony, they are structured under the grid automation
14 category.

15 Q Do you have access to the Company's current Distribution
16 Grid Plan which was filed in this case as Exhibit A-23
17 Schedule M8?

18 A Please give me a moment to find them.

19 Q Take your time.

20 A Yes.

21 Q Great. Can you turn to page, so it's page 137 of the
22 exhibit, which is page 136 of the plan.

23 A Yes.

24 Q There is a table at the bottom with a header, Exhibit
25 10.1.3, Key Investment and Timeline for Grid Automation;

1 do you see that?

2 A Yes.

3 Q O.K. Can you explain to me the relationship of the
4 categories in the top row of numbers, grid automation, to
5 the categories below it; are they included within it or
6 are they incremental to it?

7 A Please give me a moment.

8 Q Uh-huh.

9 A From my understanding from reading the table, the
10 categories sum up to the total listed at the bottom on
11 page 138.

12 Q Thank you. Thank you, that's helpful. So grid
13 automation -- O.K. Got it. So the -- I think perhaps
14 you can sense my confusion is in the sense of in some
15 instances grid automation is discussed as the overarching
16 umbrella category that includes these other components;
17 in the DGP, grid automation is a line item and some of
18 the other components are separate line items that are not
19 included within it; would you agree?

20 A Yes.

21 Q O.K. How does -- in the sense that it's used in this
22 table, Exhibit 10.1.3 in Exhibit A-23 Schedule M8, the
23 Distribution Grid Plan, how does distribution automation
24 fit within these rows; is it synonymous with grid
25 automation or is it something else?

1 A Please give me a moment.

2 Q Take your time.

3 A Do you mind repeating your question again?

4 Q Sure. How does distribution automation in the sense that
5 we've talked about it today fit with or not grid
6 automation as listed in the table, are they the same
7 thing or are they something different, can you explain?

8 A In Exhibit A-23 Schedule M8, what is listed as grid
9 automation, yes, that is the distribution automation is
10 listed in that category.

11 Q They're synonymous for purposes of that table?

12 A Correct.

13 Q Great. Thank you. O.K. Eye level, just to set some
14 context, you had mentioned today reclosers, and you talk
15 about those in your testimony. High level, reclosers do
16 what?

17 A Can you specify, do you mean in the terms of automation,
18 the specific distribution automation, grid automation?

19 Q Yes. Yep.

20 A In terms of distribution automation, reclosers do a few
21 things. First of all, the reclosers, from a safety
22 perspective, have a ground-hunting technology that can
23 sense when there is a ground on a 4.8 kV delta circuit
24 that will de, potentially will open and deenergize the
25 circuit to mitigate a risk of a potential energized

1 downed wire. Secondly, the reclosers will operate like a
2 normal recloser where they will go through a relay scheme
3 if they see a fault to try and clear it before opening.
4 Third, they can act as what I, in terms I use in my
5 testimony as switches or tie reclosers that can
6 sectionalize outages, which means essentially reducing
7 the number of customers that are impacted from an outage,
8 as well as being able to connect two circuits together so
9 when damage does occur on a circuit, the number of
10 customers impacted is reduced.

11 Q Thank you. They have slightly -- well, slightly is -- I
12 don't really know what slightly means. They have
13 somewhat different functions on a 4.8 kV circuit and a
14 13.2 kV circuit when we're talking about DTE's system; is
15 that fair?

16 A I would say on the 4.8 kV circuit, they perform the
17 ground-hunting capability that is not needed on the 13.2
18 circuit.

19 Q That's the safety measure?

20 A Correct. Correct.

21 Q High level in your understanding as the person who is the
22 director of this program and not asking you for -- well,
23 high level in your understanding from the work you did in
24 this program, what's a ballpark service life for a
25 recloser, or a range?

1 A It is my understanding, subject to check, that the
2 average life is about 20 years.

3 Q Thank you. DTE's plan is to install reclosers on what --
4 this is again a ballpark, high-level context type
5 question. DTE's plan, as you have -- well, DTE's plan in
6 your understanding from your work in the program is to
7 install reclosers on kind of what high-level portion of
8 its overhead distribution circuits, a fraction of them,
9 half of them, all of them, that's the type of answer I'm
10 looking for?

11 A It is my understanding that the Company plans to install
12 reclosers on the majority of their overhead distribution
13 circuits where they do not currently exist today.

14 Q And so a majority can mean like a few things, right; it
15 can mean, well, I have a 51% majority in the House of
16 Commons, or it can mean, the majority can mean most. Do
17 you mean like more than 50% or do you mean most, or do
18 you mean something else?

19 A When I said majority, I mean most.

20 Q Thank you. Do you have access to Exhibit A-12 Schedule
21 B5.4, the capital spending exhibit?

22 A Please give me one minute. Can you repeat the exhibit
23 name again?

24 Q Exhibit A -- it's the one we spend the most time looking
25 at, and I always have to grab it again to get it right.

1 Exhibit A-12 Schedule B5.4.

2 A Yes.

3 Q You sponsor or cosponsor pages 17 and 18 of that exhibit
4 and schedule; is that right?

5 A Yes.

6 Q Take a look at page 17. Are you there?

7 A Yes.

8 Q Great. So line 2 has projected, has historic and
9 projected spends for distribution automation; is that
10 right?

11 A Yes.

12 Q Round numbers, 5.5 million was spent in 2022 calendar
13 year; is that right?

14 A Yes.

15 Q 27.1 million was spent in calendar year 2023; is that
16 right?

17 A Yes.

18 Q 21.2 million, give or take, was spent in 2024; is that
19 right?

20 A Not including the IRM, yes.

21 Q O.K. Yeah, thank you for that clarification. We'll get
22 to that in a minute. So 21.2 million was spent as rate
23 base capital in 2024; is that right?

24 A Yes.

25 Q And that's a projection, right, that's the projection for
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1 the, when we get to the end of 2024, right?

2 A Yes.

3 Q O.K. IRM spending for 2024 for distribution automation
4 was approved at \$26.4 million; does that sound right?

5 A One minute, please.

6 Q Take your time, and let me know what you're referring to
7 when you to answer.

8 A I was referring to my direct testimony, page SMH-8, where
9 I, the section regarding the IRM, however, that
10 information is not in there. To the best of my
11 knowledge, subject to check, that number sounds around --
12 correct.

13 Q O.K. If you want to check it, I'm referring to Table 1
14 on page 54 of Mr. Foley's revised direct testimony. I
15 don't want you to, you know, take my word for it. If you
16 want to check it, you're free to do so.

17 A No.

18 Q O.K. So total projected spend for 2024 is approximately
19 \$50 million if we include -- wait a minute. Bear with
20 me. Would you agree with me with this statement, the
21 total distribution automation spend for 2024, total
22 projected spend, would be the sum of the rate base
23 spending projected in A-12 B5.4 and the IRM spending for
24 2024 for that program; do you agree?

25 A Yes.

1 Q O.K. So give or take \$21.2 million plus \$26.4 million,
2 subject to check, right?

3 A Yes.

4 Q So give or take, what is that, \$47.6 million, subject to
5 check?

6 A Subject to check, yes.

7 Q O.K. So we went from 5 1/2 million in 2022 to 27.1
8 million in 2023 to 47.6 million in 2024, right?

9 A Correct.

10 Q O.K. In Exhibit A-12 Schedule B5.4, the projected
11 spending for distribution automation in the test year
12 2025 in rate base is \$125,625,000; is that right?

13 A Yes.

14 Q And that, and in addition to that, there's another \$24.4
15 million of IRM spending projected for 2025 in
16 distribution automation; would you agree?

17 A Subject to check from Witness Foley's testimony regarding
18 the IRM amounts, if that number is correct, yes.

19 Q So high level, around 150 million in 2025; does that
20 sound right?

21 A Yes.

22 Q In addition to -- well, let's go back to that Exhibit
23 A-23, the Distribution Grid Plan, let's go back to
24 Exhibit A-23 Schedule M8, page 137 of the exhibit or 136
25 of the report. And let me know when you're there.

1 A I am there.

2 Q Based on the table, Exhibit 10.1.3, and the earlier
3 discussion we had about grid automation being synonymous
4 with distribution automation, there are projected spends
5 for distribution automation in 2026 of \$190.6 million; is
6 that right?

7 A That is correct, according to the table on the
8 Distribution Grid Plan.

9 Q And then in 2027, a projection of projected spend of
10 \$308.6 million; is that right?

11 A That is correct.

12 Q And a projected spend in 2028 of \$469 million; is that
13 right?

14 A According to the Distribution Grid Plan, yes.

15 Q And the Company's proposal in this case is to do, for
16 2026 is to do 105 million of the 2026 figure through the
17 IRM; is that right?

18 A I do not know. That --

19 Q Do you want to check -- go ahead.

20 A I was going to say that would be a better question for
21 Witness Foley.

22 Q O.K. So I don't want to lead you astray or ask you to
23 trust me, so it might be useful to just have available to
24 you his revised direct testimony, page 54, Table 1.

25 A Please hold on. Could you please repeat the location?

1 Q Sure. Mr. Foley's revised direct testimony, page 54,
2 Table 1.

3 A Could you please repeat your original question?

4 Q If I can remember it. Oh, so the, of the 2026 spending
5 for distribution automation a/k/a grid automation in the
6 DGP of 190.6 million, the Company's proposing in this
7 case to accomplish 105 million of that through the IRM in
8 2026; is that fair?

9 A From my understanding per the table in Mr. Foley's
10 testimony, yes.

11 Q O.K. And in 2027, of the projected \$308.6 million worth
12 of distribution automation spending, the Company's
13 proposing in this case to accomplish \$180 million worth
14 of that through the IRM, fair?

15 A It was, it is my understanding from Witness Foley's
16 testimony that is correct.

17 Q O.K. So looking at the grid plan, that Exhibit 10.1.3,
18 high level, distribution automation spending for the
19 five-year period in the DGP adds up to, give or take,
20 \$1.2 billion; is that right?

21 A Subject to check without adding that up right now, that
22 sounds correct.

23 Q So we're going, high level, from \$5 1/2 million in 2022
24 and \$27.1 million in 2023, historic spending amounts, to
25 projecting \$1.2 billion of spending in this program over

1 the next five years, fair?

2 A Per the Distribution Grid Plan, that is the projection.

3 Q O.K. Take a look at your direct testimony, page 11,
4 question and answer 22. Are you there?

5 A Yes.

6 Q So at that location you identify U.S. Department of
7 Energy Report -- I'm looking at line 7 through 11. You
8 say this technology, distribution automation, plays a
9 crucial role in modernizing the power grid, as evidenced
10 by the Department of Energy or DOE Report, and then you
11 offer the title, published in September of 2016; is that
12 right?

13 A Yes.

14 Q In the footnote, and I'm not, this is not a gotcha thing,
15 I just want to look at both reports. In the footnote,
16 you actually cite a report from DOE dated December 20,
17 2016; do you see that?

18 A Yes.

19 Q O.K. So do you have access to the SharePoint folder for
20 you under DTE?

21 A Yes.

22 Q O.K. Within your folder, there's a folder called MNSC
23 hearing exhibits; do you see that?

24 A No.

25 Q Try refreshing it.

1 A Yes.

2 Q O.K. Within that folder there are two exhibits that I'd
3 ask you to open up, one is Exhibit MEC-59 and one is
4 Exhibit MEC-60. Do you have them both open?

5 A Yes.

6 Q O.K., great. And then I would ask you to look at your
7 rebuttal testimony, page 15, question and answer 35.
8 There, starting at line 13, you refer to a DOE report,
9 2016 report titled "Distribution Automation"; do you see
10 that?

11 A Yes.

12 Q And there you cite in footnote 28 a DOE report dated
13 September 29, 2016; do you see that?

14 A Yes.

15 Q So my only question -- I'm just authenticating reports
16 here. My question for you is, does Exhibit MEC-60 -- so
17 on the representation I have not modified these documents
18 in any way, does MEC-60 look familiar to you as the
19 September 2016 report that you cite in your rebuttal, and
20 does MEC-59 look familiar to you as the report you cited
21 in the footnote 1 of your direct?

22 A I do not recall. Would you like me to pull up the link?

23 Q Sure, if that helps you check.

24 A Can you repeat your question, please?

25 Q Sure. So my only object with these questions is to put
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1 these reports that I believe you cited into evidence in
2 this case, I don't have detailed questions for you about
3 them, but I want to make them part of the record. So my
4 question is, do the two reports in MEC-59 and MEC-60
5 appear to you familiar as the reports you were citing in
6 these two footnotes, one from your direct and one from
7 your rebuttal?

8 A Yes.

9 Q Thank you.

10 MR. BZDOK: Your Honor, at this time I
11 would move to admit proposed Exhibits MEC-59 and MEC-60.

12 MS. JOHNSON-BACON: No objection.

13 JUDGE WALLACE: O.K. Yeah. Is there any
14 objection to the admission of Exhibits MEC-59 and MEC-60?

15 Hearing none, those exhibits are
16 admitted.

17 MR. BZDOK: Thank you.

18 Q (By Mr. Bzdok): Let's look at another exhibit in the
19 SharePoint folder, which is proposed Exhibit MEC-65. Do
20 you have that available?

21 A One minute, please. Yes.

22 Q In Exhibit -- so Exhibit MEC-65 proposed is a discovery
23 response from you, MNSCDE-18.24; is that right?

24 A Yes.

25 Q And in this discovery response, in the question we had
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1 asked you: For 4.8 kV circuits automated in 2022 and
2 2023 as part of the Company's Distribution Automation
3 program to install reclosers, identify the SAIDI minutes
4 for each circuit for the five years preceding the
5 recloser installation and the years since the recloser
6 installation, correct?

7 A Yes.

8 Q And SAIDI is System Average Interruption Duration Index;
9 is that right?

10 A Yes.

11 Q And you attached an Excel attachment, which we have
12 included in this response consisting of four pages of
13 data in table form; is that right?

14 A Yes.

15 Q And the data in table form contains a circuit and an
16 install year, which is abbreviated IY; is that right?

17 A Yes.

18 Q And if I'm understanding the table right, IY-5 means five
19 years before installation, IY-4 means four years before
20 installation, IY-3, 2, and 1 would mean similar things
21 for those numbers of years, and then IY is the
22 installation year; is that right?

23 A Yes.

24 Q And then IY+1 is the year after installation; is that
25 right?

1 A Yes.

2 Q O.K. From this table we don't know when within a year a
3 recloser and related equipment was installed on a
4 particular circuit; would you agree?

5 A Yes.

6 Q Could be January, could be December, could be June,
7 right?

8 A Yes.

9 Q So we don't really know, we -- the -- let me try this
10 question a different way.

11 So if we don't know when during the year
12 the recloser was installed, we don't really know how much
13 of the year is captured in terms of SAIDI minutes before
14 installation and SAIDI minutes after installation for
15 that install year; would you agree?

16 A Yes.

17 Q O.K. So that the SAIDI minutes for the install year is
18 somewhat inconclusive in terms of what -- let me strike
19 that question. I'll move on.

20 Of the reclosers listed on these four
21 pages of data, one was installed in 2022; would you
22 agree?

23 A Yes.

24 Q And so as of the date of this discovery response, which I
25 think was a few days ago, we only have SAIDI data post-

1 installation for one of these circuits; would you agree?

2 A Yes.

3 Q And understanding -- and I understand and I will concede
4 and acknowledge to you that, you know, lots of different
5 things go into the number of SAIDI minutes a circuit
6 experiences in a year. Understanding that there are a
7 lot of variables there, would you agree that, on the face
8 of it, the SAIDI minutes in the year after installation
9 for the one circuit that we have that data for was higher
10 than the SAIDI minutes in the three years preceding
11 installation, in each of the three years preceding
12 installation?

13 A Yes.

14 Q In your opinion, is this sufficient proof of actual
15 performance to support spending \$150 million on this
16 program in the projected test year?

17 A Can you repeat the question?

18 Q In your opinion, is this sufficient proof of actual
19 performance on DTE's system to support spending \$150
20 million on this program in the projected test year?

21 A That was not the intent of this information.

22 Q So you would not suggest that this data we have here
23 would support, would be proof of actual performance to
24 support \$150 million of projected spending on this
25 program in the projected test year, you would not hold

1 this forth as providing that kind of support?

2 A I wouldn't characterize it that way.

3 Q O.K. Would you -- in your opinion, was this sufficient
4 proof of actual performance on DTE's system to support
5 spending \$1.2 billion on this program over the five years
6 of the Distribution Grid Plan?

7 A Again, I wouldn't characterize it that way.

8 Q O.K. In your direct -- let's look at your direct
9 testimony.

10 MR. BZDOK: Oh, your Honor, I'll move to
11 admit proposed Exhibit MEC-65.

12 MS. JOHNSON-BACON: No objection.

13 JUDGE WALLACE: MEC-65 is admitted.

14 MS. JOHNSON-BACON: Your Honor, is this a
15 good time to take a break?

16 JUDGE WALLACE: Mr. Bzdok.

17 MR. BZDOK: Could I get one or two more
18 questions in --

19 JUDGE WALLACE: Sure.

20 MR. BZDOK: -- and then we'll move
21 topics?

22 JUDGE WALLACE: O.K. And then we'll take
23 a break. O.K., yeah, go ahead, a couple minutes.

24 Q (By Mr. Bzdok): Does DTE have, to your knowledge,
25 Ms. Hartwick, any other data on actual performance of

1 reclosers on the Company's system other than this
2 information?

3 A Can you repeat the question?

4 MR. BZDOK: Lori, can you read it back?

5 COURT REPORTER: Yes.

6 (The record was read aloud as follows:

7 "Q Does DTE have, to your knowledge, Ms. Hartwick,
8 any other data on actual performance of
9 reclosers on the Company's system other than
10 this information?")

11 A Yes.

12 Q (By Mr. Bzdok): O.K. Is it in the record anywhere in
13 this case?

14 A Not to my knowledge.

15 MR. BZDOK: O.K. Those are my one or two
16 questions prior to a break.

17 JUDGE WALLACE: O.K., everybody, let's
18 take 15 minutes. It's 10:10. 10:25, I'll see you back
19 here then.

20 MR. BZDOK: So before we go --

21 JUDGE WALLACE: Yes.

22 MR. BZDOK: Are we off the record? Are
23 we off the record?

24 JUDGE WALLACE: Off the record.

25 (Recess from 10:10 a.m. until 10:51 a.m.)

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1 JUDGE WALLACE: All right. Please
2 continue, Mr. Bzdok.

3 MR. BZDOK: Thank you, your Honor.

4 Q (By Mr. Bzdok): Ms. Hartwick, would you please take a
5 look at your direct testimony, page 18, question and
6 answer 31.

7 A I'm there.

8 Q Generally speaking, in this question and answer you
9 discuss a cost-benefit model for distribution automation
10 that allows the Company to prioritize circuits for these
11 activities; is that generally a fair characterization?

12 A That is what's written in my direct testimony.

13 Q O.K. And then in your rebuttal testimony you sponsor,
14 one of the exhibits that you sponsor is Exhibit A-53
15 Schedule RR2 titled Automation Prioritization Tool; do
16 you see that?

17 A Yes.

18 Q Is that the same document that you're discussing in your
19 direct at Q-A-31?

20 A Yes.

21 MR. BZDOK: O.K. At this point, your
22 Honor, I believe it would be appropriate in order to
23 review this document which has been designated by the
24 Company as Confidential Critical Electric Infrastructure
25 Information for us to withdraw from the public section

1 and move to the separate Confidential CEII session.

2 JUDGE WALLACE: You are correct. Let's
3 see.

4 MR. CHRISTINIDIS: Your Honor. When we
5 go off the record, I just wanted to note something.

6 JUDGE WALLACE: O.K. All right. We're
7 off the public record.

8 (At 10:53 a.m., off-record discussion and recess.)

9 - - -

10 (Transcript continues on Page 882 of the
11 Confidential CEII Record.)

12 - - -

Friday, September 6, 2024

At 11:55 a.m.

- - -

(Transcript continues following Page 895 of the
Confidential CEII record.)

- - -

JUDGE WALLACE: All right. We're back on
the public record in Case No. U-21534, is that right,
21534. And Mr. Bzdok, please go ahead.

MR. BZDOK: Your Honor, at this time, in
order to streamline, I would move for the admission
without any questions of the following exhibits if
there's no objection: MEC-61, which is Discovery
Response MNSCDE-18.17; MEC-62, which is Response 18.20a;
MEC-63, which is Response 18.21, I'll note that has an
NDA confidential attachment which we are not seeking to
admit; MEC-64, which is Response 18.23 with its
attachment which is public; and MEC-66, which is Response
18.25.

MS. JOHNSON-BACON: No objection, your
Honor.

JUDGE WALLACE: O.K. Then we're
admitting Exhibits MEC-61 through MEC-64, and MEC-66.

MR. BZDOK: Thank you, your Honor.

JUDGE WALLACE: Those exhibits are
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1 admitted.

2 MR. BZDOK: Thank you, your Honor.

3 JUDGE WALLACE: Ms. Johnson-Bacon, do you
4 have any redirect for Ms. Hartwick?

5 MS. JOHNSON-BACON: Your Honor, if I
6 could have two minutes; if I have any, it won't be much.

7 JUDGE WALLACE: O.K. Off the record,
8 then, for just a couple minutes.

9 MS. JOHNSON-BACON: Thank you.

10 (Off-record from 11:57 a.m. until 11:59 a.m.)

11 JUDGE WALLACE: Any redirect,
12 Ms. Johnson-Bacon?

13 MS. JOHNSON-BACON: Your Honor, the
14 Company has no redirect for Ms. Hartwick.

15 JUDGE WALLACE: Thank you. I forgot to
16 ask before, does anybody else have any questions for
17 Ms. Hartwick? (No response.)

18 MR. BZDOK: Ms. Hartwick, thank you for
19 your time and your answers today.

20 THE WITNESS: Thank you.

21 JUDGE WALLACE: Thank you, Ms. Hartwick,
22 and are you excused.

23 (The witness was excused.)

24 - - -

25 JUDGE WALLACE: And it is noon. Is 45
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1 minutes O.K. for lunch?

2 MS. JOHNSON-BACON: That's adequate with
3 the Company. Thank you.

4 JUDGE WALLACE: O.K. Then let's meet
5 back here at 12:45. Thank you, all.

6 MS. JOHNSON-BACON: Thank you.

7 (At 11:59 p.m., the hearing recessed for lunch.)

8 - - -

Friday, September 6. 2024

At 12:51 p.m.

- - -

(Hearing resumes following the lunch recess.)

JUDGE WALLACE: We're back on the record,
the public record, in Case No. U-21534. And so,
Ms. Johnson-Bacon, please present your witness.

MS. JOHNSON-BACON: Good afternoon, your
Honor. DTE Electric Company would call Witness Elliott
Andahazy. Ms. Penn, do you want to swear the witness.

COURT REPORTER: Yes.

- - -

M O R G A N E L L I O T T A N D A H A Z Y
was called as a witness on behalf of DTE Electric Company
and, having been duly sworn to testify the truth, was
examined and testified as follows:

DIRECT EXAMINATION

BY MS. JOHNSON-BACON:

Q Good afternoon. Please state your name and business
address for the record.

A Morgan Elliott Andahazy, DTE Energy is located at One
Energy Way, Detroit, Michigan, and I believe it's 48226.

Q Did you file with the Commission a document entitled the
Qualifications and Revised Direct Testimony of Morgan
Elliott Andahazy, consisting of a cover sheet and 117

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1 pages of questions and answers?

2 A Yes.

3 Q Do you have any changes you wish to make to your revised
4 direct testimony?

5 A No.

6 Q Is that, then, the revised direct testimony that you're
7 adopting today?

8 A Yes.

9 Q Are you sponsoring any exhibits associated with your
10 revised direct testimony in this case?

11 A Yes.

12 Q For purposes of identification, are these seven direct
13 exhibits designated as Exhibit A-12 Schedule B5.4,
14 consisting of 26 pages; Exhibit A-12 Schedule B5.4.8,
15 consisting of one page; Exhibit A-23 Schedule M5,
16 consisting of 131 pages; Exhibit A-23 Schedule M9,
17 consisting of 25 pages; Schedule A-23 -- I'm sorry --
18 Exhibit A-23 Schedule M10, consisting of 23 pages;
19 Exhibit A-23 Schedule M12, consisting of 41 pages; and
20 Exhibit A-23 Schedule M13, consisting of 26 pages?

21 A Yes.

22 Q Were these exhibits prepared by you or at your direction?

23 A Yes.

24 Q Do you have any changes to make to any of your direct
25 exhibits?

1 A No.

2 Q Did you also file with the Commission a document entitled
3 the Rebuttal Testimony of Morgan Elliott Andahazy,
4 consisting of a cover sheet and 44 pages of questions and
5 answers?

6 A Yes.

7 Q Do you have any changes you wish to make to your rebuttal
8 testimony?

9 A Yes. I have three changes.

10 Q And those changes are?

11 A The first one is on page MEA-9-Rebuttal -- excuse me --
12 on page MEA-9 Rebuttal on line 10, the sentence should
13 read, "For All-Weather SAIFI benefits" rather than "For
14 All-Weather SAIDI benefits".

15 Q Do you have any additional changes?

16 A Yep. The second one is on page MEA-13-Rebuttal, in Table
17 1, the header should say "All-Weather Customer
18 Interruptions" rather than "All-Weather Customer
19 Interruptions Excluding MEDs".

20 The third and final change I would like
21 to make is on page MEA-41-Rebuttal, on line 2, the
22 question should read, "the URD Replacement Program"
23 rather than "the Breaker Replacement Program".

24 Q With those changes, is that, then, the rebuttal testimony
25 you're adopting today?

1 A Yes.

2 Q Are you sponsoring any exhibits associated with your
3 rebuttal in this case?

4 A Yes.

5 Q For purposes of identification, are these 13 rebuttal
6 exhibits designated as Exhibit A-51 Schedule PP1,
7 consisting of one page; Exhibit A-51 Confidential
8 Schedule PP2, consisting of one page; Exhibit A-51
9 Schedule PP3, consisting of one page; Confidential
10 Exhibit A-51 Schedule PP4, consisting of one page,
11 Exhibit A-51 Schedule PP5, consisting of one page;
12 Confidential Exhibit A-51 Schedule PP6, consisting of one
13 page; Exhibit A-51 Schedule PP7, consisting of one page;
14 Confidential Exhibit A-51 Schedule PP8, consisting of one
15 page; Exhibit 51 Schedule PP9, consisting of 153 pages;
16 Confidential Exhibit A-51 Schedule PP10, consisting of
17 one page; Exhibit A-51 Schedule PP12, consisting of one
18 page; Exhibit A-51 Schedule PP13, consisting of 15 pages;
19 and Exhibit A-51 Schedule PP14, consisting of one page?

20 A Yes.

21 Q Were these exhibits prepared by you or at your direction?

22 A Yes.

23 Q Do you have any changes to make to any of these 13
24 rebuttal exhibits?

25 A No.

1 MS. JOHNSON-BACON: Your Honor, DTE
2 Electric moves to bind into the record the
3 Qualifications, Revised Direct Testimony, Revised
4 Rebuttal Testimony, with the changes indicated on the
5 record by Witness Elliott Andahazy, and for the admission
6 at the end of cross-examination the foregoing exhibits
7 supported by Ms. Elliott Andahazy's direct testimony, and
8 we offer her for direct cross-examination -- direct
9 cross-examination, T.J., do that -- for
10 cross-examination.

11 JUDGE WALLACE: All right.

12 MS. JOHNSON-BACON: Thank you.

13 JUDGE WALLACE: All right. Is there any
14 objection to binding in the revised direct testimony of
15 Ms. Elliott Andahazy?

16 Hearing none, the testimony is bound in.

17 Is there any objection to binding in the
18 revised rebuttal testimony, I'll note that those
19 revisions were made on the record?

20 Hearing none, the rebuttal testimony is
21 bound in.

22 (Testimony bound in.)

23 - - -

24

25

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

QUALIFICATIONS
AND
REVISED DIRECT TESTIMONY
OF
MORGAN ELLIOTT ANDHAZY

DTE ELECTRIC COMPANY
QUALIFICATIONS AND REVISED DIRECT TESTIMONY OF MORGAN
ELLIOTT ANDAHAZY

Line
No.

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

2 A1. My name is Morgan Elliott Andahazy (she/her/hers). My business address is One
3 Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Electric Company
4 (DTE Electric or Company).

5

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

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

8

9 **Q3. Please state your educational background.**

10 A3. I hold a Bachelor of Science in Engineering (Industrial and Operations Engineering)
11 and a Master of Business Administration, both from the University of Michigan, Ann
12 Arbor.

13

14 **Q4. Do you have any professional certifications or other certificates?**

15 A4. I received my Lean Six Sigma Black Belt certification in 2009.

16

17 **Q5. Please summarize your work experience.**

18 A5. In 2007, I joined DTE Electric as a contract employee supporting the Distribution
19 Operations Continuous Improvement (DOCI) team. In March 2008, I joined DTE
20 Electric as a full-time employee and a Project Lead within the DOCI team. As a Project
21 Lead, I was responsible for measuring and improving productivity within the Electric
22 Field Operations (EFO) organization. During this time, I obtained my Lean Six Sigma
23 Black Belt certification based on work I did with EFO Productivity projects. In 2009,
24 I transitioned to the Continuous Improvement (CI) Manager for Distribution

Line
No.

1 Operations (DO) where I was responsible for the team of Project Leads supporting
2 improvement projects throughout DO. In March 2010, I moved to a new developmental
3 assignment as a Field Supervisor for the Underground (UG) Cable Pulling team at the
4 Trombly Service Center. At Trombly, I was responsible for overseeing the daily
5 construction work performed by the UG Cable Pullers and supervising a Union-
6 represented workforce. In January 2011, I was promoted to the CI Manager for
7 Corporate Services. I was responsible for coordination and implementation of CI
8 training within the organization, and I led the team of CI experts responsible for
9 improvement projects. In October 2011, I transitioned to Manager, Trombly Service
10 Center, where I was responsible for all UG operations (cable pulling and cable splicing)
11 for the Southeast (SE) Region of DO. In April 2013, my role expanded to Manager, SE
12 Region, which consisted of three service centers (Trombly, Redford, and Caniff) and
13 included all Overhead (OH) and UG operations in the SE Region. In March 2016, I was
14 promoted to Director, Service Operations responsible for all OH and UG operations in
15 Southwest (SW), Northwest (NW), and Northeast (NE) regions in DO. In this role, I
16 also assisted in Local 17 contract negotiations. In October 2017, I assumed the position
17 of Director, Advanced Distribution Management System (ADMS). I lead the team
18 responsible for the successful implementation of the new ADMS. This team was
19 responsible for the strategic direction, vendor selection, and implementation of all
20 ADMS components including the Generation Management System (GMS), Energy
21 Management System (EMS), Outage Management System (OMS), Distribution
22 Management System (DMS), and the Network Management System (NMS). In April
23 2022, I transitioned to the Director, Project Management Organization (PMO) within
24 Electric Distribution Operations (DO). In this role, I led the team that was responsible

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1 for managing the execution of all strategic capital programs and projects. As of July
2 2023, my role has shifted to the management of only the strategic capital programs.

3

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

5 A6. As Director – PMO Programs, I lead the team that is responsible for managing the
6 execution of the programs making up the majority of the Infrastructure Resilience and
7 Hardening strategic investment discussed in my direct testimony. My team consists of
8 the project managers, project coordinators, construction/field supervisors, engineers,
9 and the leadership/support teams required to manage and track the progress of our
10 investments.

11

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

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

15 U-20836 2022 DTE Electric Rate Case

16 U-21297 2023 DTE Electric Rate Case

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1 **Purpose of Testimony**

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

3 A8. The purpose of my testimony is to support, as reasonable, prudent and necessary, the
4 historical capital expenditures for 2022 and projected capital expenditures for 2023
5 through December 31, 2025, in the distribution strategic capital category of
6 Infrastructure Resilience and Hardening.

7

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

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

10	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
11	A-12	B5.4	Projected Capital Expenditures – Distribution Plant (Pages
12			1, 2, 13, 19-26)
13	A-12	B5.4.8	4.8kV Hardening and Pole & Pole Top Maintenance and
14			Modernization (PTMM) – Details
15	A-23	M5	Distribution Plant Capital Project Detail – The
16			Infrastructure Resilience and Hardening Pillar
17	A-23	M9	Wood Pole Maintenance Specification
18	A-23	M10	Pole Top Maintenance Specification
19	A-23	M12	4.8kV Hardening Technical Conference
20	A-23	M13	PTMM Benefit Cost Analysis Whitepaper

21

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

23 A10. Yes, they were.

24

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1 **Q11. How is your testimony organized?**

2 A11. My testimony consists of the following parts:

3 Part I: The Infrastructure Recovery Mechanism

4 Part II: The Infrastructure Resilience and Hardening Pillar

5

6 **Part I: The Infrastructure Recovery Mechanism (IRM)**

7 **Q12. Are any of the programs you are supporting impacted by the Company's**
8 **Distribution Infrastructure Recovery Mechanism (Distribution IRM or IRM)?**

9 A12. Yes, as described by Company Witness Foley in his testimony, in its December 1, 2023
10 Order in Case No. U-21297 (December 2023 Order) the Commission authorized IRM
11 treatment for the Breaker Replacement Program and the URD Replacement Program.
12 IRM treatment was authorized starting on December 1, 2023, and running through the
13 end of 2025.

14

15 **Q13. Is the Company proposing any investment in these programs during the bridge**
16 **and/or test years beyond what the Commission previously authorized for recovery**
17 **through the IRM?**

18 A13. Yes, as reflected in Exhibit A-12, Schedule B5.4, Page 13, Lines 16 and 18, the
19 Company is proposing recovery of investment in these programs made in 2023 prior to
20 the IRM being authorized by the Commission in its December 2023 Order. All bridge
21 and test year investments in these programs after the IRM was authorized is being
22 recovered through the IRM. As such, 2024 investment (column d) and 2025 investment
23 (columns e and g) are \$0 in the exhibit, reflecting no recovery is being proposed through
24 base rates for these programs in those years.

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Q14. Is the Company proposing recovery for any additional investment in these programs through the IRM beyond the test year of this case?

A14. Yes, as described by Company Witness Foley, the Company is proposing a two-year extension of the IRM (i.e., calendar years 2026 and 2027). As part of that extension the Company is proposing recovery of additional Breaker Replacement Program investment and URD Replacement Program investment as captured in Exhibit A-33, Schedule X1, Lines 4 and 5.

Q15. Is the Company proposing any additional programs be authorized for IRM treatment beyond the test year of this case?

A15. Yes, as part of the proposed two-year IRM extension described by Company Witness Foley, the Company is proposing that the Pole and Pole Top Maintenance & Modernization (PTMM) program be authorized for IRM treatment. The Company is proposing \$150 million of capital investment in 2026 and \$200 million of capital investment in 2027 for this program, as captured in Exhibit A-33, Schedule X1, Line 7.

Q16. Why is the Pole and Pole Top Maintenance & Modernization (PTMM) program a good candidate for IRM treatment?

A16. There are three screening criteria that the Company used to identify the capital programs it proposed to be authorized for IRM treatment. Specifically, the Company looked for programs that had the following characteristics:

- Critical to customer safety, reliability, and/or resiliency
- Sufficient size and duration
- Well-understood scope

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The Company believes that the PTMM program meets these criteria and therefore is a good candidate to be authorized for IRM treatment.

3

4

5

Part II: The Infrastructure Resilience and Hardening Pillar

6

Q17. What is the Infrastructure Resilience and Hardening Pillar?

7

A17. The Infrastructure Resilience and Hardening Pillar includes programs and projects focused on near-term grid infrastructure investments to harden the system against an increasing frequency and severity of high winds and storms¹, address frequent outage circuits, and replace damaged and/or defective infrastructure. These investments support employee and public safety, customer reliability, and reduce risk to the grid.

8

9

10

11

12

13

Capital investment details of programs and projects in this category are included in the following:

14

15

- Exhibit A-12, Schedule B5.4, page 13 – Infrastructure Resilience and Hardening Capital Investments;

16

17

- Exhibit A-12, Schedule B5.4.8 – 4.8kV Hardening Program and PTMM Program Details;

18

19

- Exhibit A-23, Schedule M5 – Infrastructure Resilience and Hardening Program and Project Charters; and

20

21

- Exhibit A-12, Schedule B5.4 includes AFUDC for this category on page 19 and plant activity on pages 20 and 21, described in more detail by Company Witness Kryscynski.

22

23

24

¹ The severity of recent storm activity is discussed by Company Witness Hill beginning on page BLH-9.

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Q18. What programs and projects fall under the Infrastructure Resilience and Hardening Pillar?

A18. The Infrastructure Resilience and Hardening Pillar consists of the following programs and projects:

- 4.8kV Hardening Program
- Pole and Pole-Top Maintenance and Modernization (PTMM) Program
- Substation Risk Projects
- Frequent Outage Programs (CEMI²)
- Cable Replacement Program (System Cable)
- Underground Residential Distribution (URD) Replacement Program
- Breaker Replacement Program
- Mobile Fleet Program
- Pontiac Vaults Projects
- 40kV: Automatic Pole Top Switch Program
- Disconnect and Switcher Replacement Program
- Steel Pole Highway Crossings Program
- Batteries and Chargers Replacement Program
- SCADA Pole Top Device Replacement
- Substation Regulator Replacement
- Portable Generators Program

The 4.8kV Hardening Program

Q19. Why was the 4.8kV Hardening Program created?

² Customers Experiencing Multiple Interruptions (CEMI) is an industry term that is often used interchangeably with frequent outages.

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1 A19. The 4.8kV Hardening Program was developed in 2017 to be a near-term, cost-effective
2 way to improve public safety and reliability in and around the City of Detroit. The
3 program improves safety by removing Detroit Public Lightning Department (DPLD)
4 arc wire where it is co-located with DTE equipment and is therefore at risk of becoming
5 energized. The program improves reliability by replacing damaged poles and pole-top
6 equipment in locations that contain some of the oldest infrastructure in DTEE's service
7 territory. The 4.8kV Hardening Program allows for a more rapid removal of arc wire
8 alongside improved reliability and safety, ahead of the longer-term circuit conversions
9 that will ultimately replace 4.8kV infrastructure.

10

11 **Q20. What is the scope of the 4.8kV Hardening Program?**

12 A20. The scope of the 4.8kV Hardening Program includes all overhead circuits in and around
13 the city of Detroit in areas known to contain DPLD arc wire.

14

15 The program's work activities are listed below:

- 16 • Test all utility poles that have Company equipment attached and replace or
17 reinforce those poles as needed.
- 18 • Trim trees, as required, to support construction activities.
- 19 • Remove DPLD arc wire from Company-owned equipment; ensure the
20 remaining Company wires are left in a safe configuration.
- 21 • Remove DPLD distribution wire from Company-owned equipment when it can
22 be confirmed that the wire is not serving customers.
- 23 • Replace wooden crossarms with fiberglass crossarms as needed.
- 24 • Replace other pole-top equipment as required, allowing for rebalancing of the
25 remaining conductor.

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- 1 • Remove service lines to abandoned properties.
- 2 • Remove primary conductor in sparsely populated areas (primary
- 3 deconductoring).
- 4 • Perform any additional work necessary as dictated by field conditions.

5

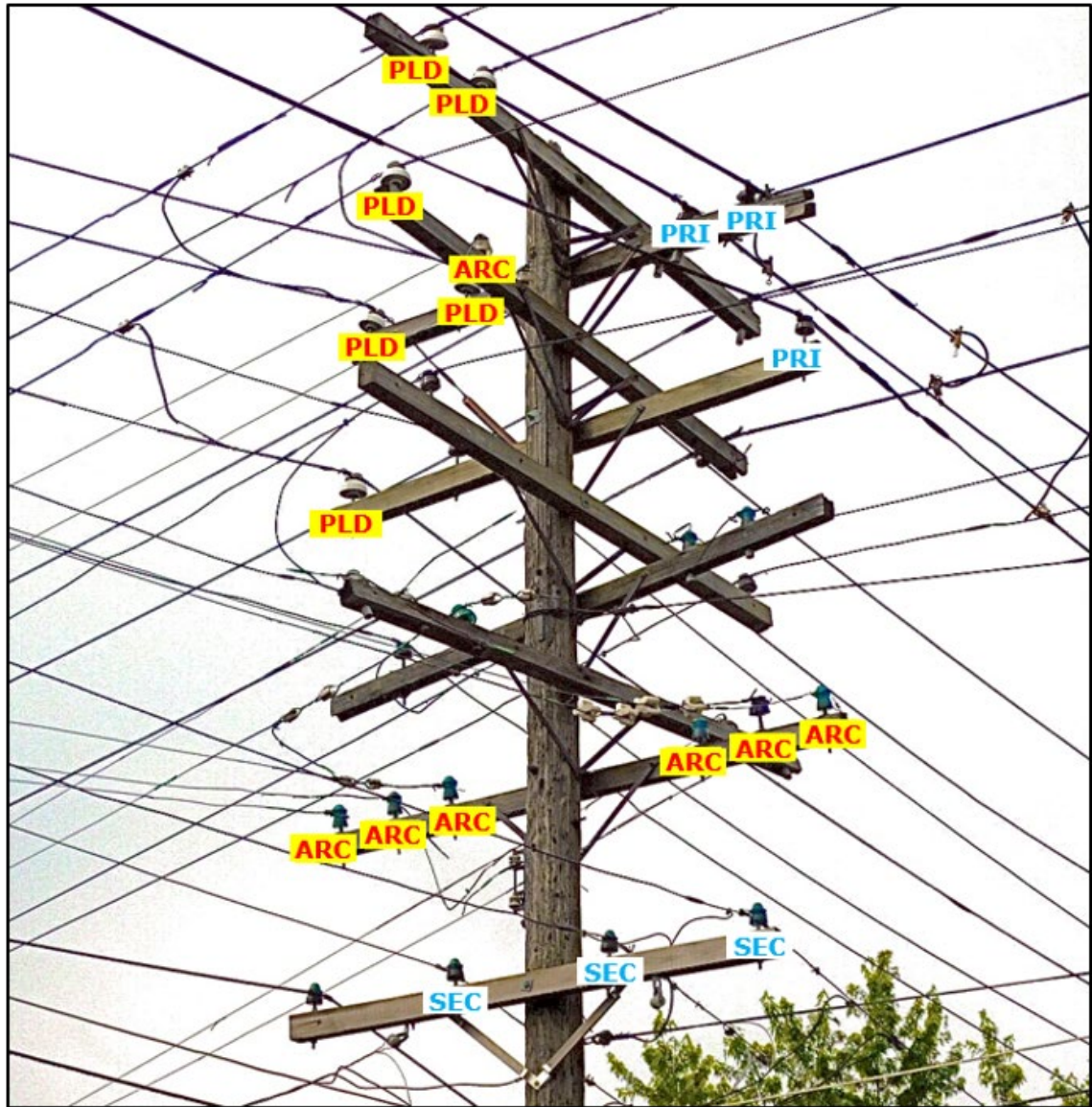
6 Figures 1 and 2 show examples of before and after the 4.8kV Hardening work activities

7 are completed.

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Figure 1. Before Hardening – Example



PLD: DPLD Distribution Wire

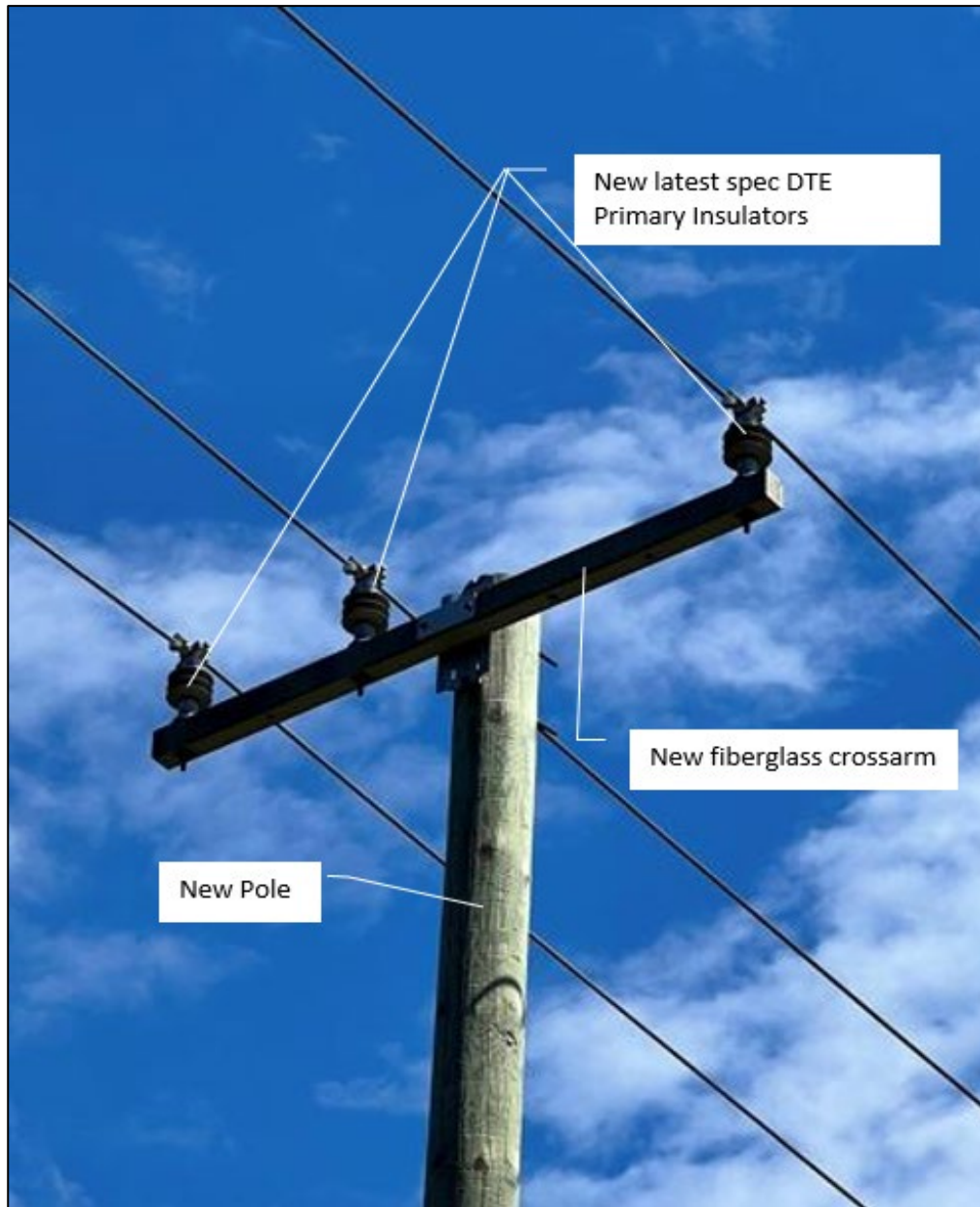
ARC: DPLD Arc Wire

PRI: DTEE Primary Wire

SEC: DTEE Secondary Wire

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Figure 2. After Hardening – Example



2

3 **Q21. Why does the 4.8kV Hardening Program include tree trimming and pole and pole-**
4 **top equipment replacement rather than only removing DPLD arc wire?**

5 **A21.** These additional activities beyond removing DPLD arc wire are necessary to make the
6 worksite accessible for field crews, and safe for both field crews and the public. Tree
7 trimming is necessary for field crews to gain access to the poles as well as the wire.

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1 Testing and replacing or reinforcing poles is necessary to make the site safe and
2 supports improved resiliency and reliability. Crossarm replacement and rebalancing is
3 likewise necessary, as removing the DPLD arc wire only could potentially leave
4 crossarms dangerously unbalanced and create hazards. Unbalanced crossarms may
5 occur because DPLD arc wire and the Company's overhead lines were originally
6 installed to provide equal force on each side of the crossarm; when the arc wire is
7 removed, the remaining DTE wires exert force on only one side of the crossarm,
8 resulting in the need for the wires to be rebalanced so they are properly supported.

9

10 **Q22. Has the Commission previously supported the Company's investments in the**
11 **4.8kV Hardening Program?**

12 A22. Yes. The Commission approved 4.8kV Hardening Program investments in Case Nos.
13 U-20162, U-20561, U-20836, and U-21297. The 4.8kV Hardening Program aligns with
14 the Commission's expectation that the Company remove DPLD arc wire³.

15

16 The Commission has since reiterated its support for the 4.8kV Hardening Program in
17 Case No. U-21297 stating:

18 Completing this work is crucial to the residents and businesses located
19 in areas that contain abandoned arc wire and the Commission agrees
20 with the Staff that the removal of the arc wire should be going faster.
21 While the work is expensive (in part because hardening means going
22 back to the same pole twice), comprehensively addressing the safety and
23 equity concerns is a priority and the Commission recognizes that

³ In its September 28, 2018 Order in Case No. U-18484 the Commission noted that "[a]ppropriate integration of arc wire removal with other DTE Electric programs, such as the hardening and conversion programs, is a crucial aspect of planning and executing strategies." (U-18484 Order, pg. 6)

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conversion takes much longer than hardening. ... the Commission approves the requested bridge period and test year funding and expects to see results in DTE Electric's next rate case, including an accelerated removal of the arc wire as discussed by the Staff. (U-21297 - Commission Order, December 1, 2023, p. 93-94)

Q23. What stakeholder engagements for the 4.8kV Hardening Program were required by the Commission in Order No. U-20836?

A23. The Company was directed to hold stakeholder engagements in the first quarter of 2023 covering the following items:

- Complete a full analysis that demonstrates the specific costs of hardening, conversion, distributed energy resources (DERs), tree trimming, and/or other alternatives compared with the benefits, such as improving safety and reducing System Average Interruption Index (SAIDI) and System Average Interruption Frequency Index (SAIFI).
- Conduct an analysis of the capabilities/constraints of the 4.8kV system and how it affects the use of DERs and electric vehicles (EVs) compared to conversion to a 13.2kV system.
- Complete a full analysis and comparison of alternatives to hardening including use of DERs and EVs compared to conversion to a 13.2kV system.
- Complete a full analysis of optimal reliability-focused distribution technologies and plan a course of action for arriving at an equitable future for environmental justice and other disadvantaged communities.
- Calculate the miles of arc wire removed to date, the estimated miles of arc wire remaining, the level of confidence that all arc wire is captured in the Company's

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1 inventory, the cost of removal with the 4.8kV hardening program, and the cost
2 without the program.

3

4 **Q24. Did the Company perform the alternatives analysis and host the Technical**
5 **Conference in Q1 2023?**

6 A24. Yes, the Company presented an overview of its distribution system and alternatives to
7 the 4.8kV Hardening Program at the DTE Electric 4.8kV Technical Conference hosted
8 by the MPSC Staff on March 22, 2023. This presentation can be found in Exhibit A-
9 23, Schedule M12 - 4.8kV Hardening Technical Conference.

10

11 **Q25. What was presented to the MPSC Staff and Intervenors regarding the 4.8kV**
12 **Hardening Program in the March 22, 2023, Technical Conference?**

13 A25. The Company presented the following:

- 14 • An overview of the 4.8kV distribution system,
- 15 • A comparison of the 4.8kV and 13.2kV distribution systems,
- 16 • A list of considerations for the implementation of electric vehicles and
17 distributed energy resources,
- 18 • An overview of the City of Detroit and DPLD arc wire infrastructure,
- 19 • A description of the program scope and customer benefits of the 4.8kV
20 Hardening Program, and
- 21 • A discussion of alternatives to the 4.8kV Hardening Program.

22

23 The March 22, 2023, Technical Conference materials (including the agenda,
24 presentation slides, video recording of the meeting, and follow-up questions and

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1 answers) can be found at [https://www.michigan.gov/mpsc/consumer/electricity/dte-](https://www.michigan.gov/mpsc/consumer/electricity/dte-electric-4-8kv-technical-conference)
2 [electric-4-8kv-technical-conference](https://www.michigan.gov/mpsc/consumer/electricity/dte-electric-4-8kv-technical-conference).
3

4 **Q26. What alternatives were considered to the 4.8kV Hardening Program?**

5 A26. Four alternatives were considered: arc wire removal, pre-conversion, conversion, and
6 microgrids, and their associated required investment, execution complexity, and
7 anticipated customers benefits (Table 1).
8

9 Arc Wire Removal includes trimming trees as necessary, reinforcing/replacing poles
10 and replacing pole top equipment as necessary, removing DPLD arc wire, and
11 rebalancing cross arms.
12

13 Pre-conversion includes trimming trees as necessary, rebuilding pole tops, replacing
14 poles and transformers as necessary, removing DPLD arc wire, reconductoring
15 overhead lines as needed, installing neutral wire, and rebuilding underground
16 infrastructure as necessary.
17

18 Conversion includes all pre-conversion activities as well as substation expansions as
19 necessary, new substation construction as necessary, new circuit construction, circuit
20 reconfiguration, and load transfer work activities.
21

22 Microgrids includes all pre-conversion activities as well as solar and battery storage
23 installation, support equipment installation (inverters, switchboards, communication
24 gateways, reclosers, etc.), and site preparation needed to house this equipment.
25

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Table 1. Hardening Program Alternatives Overview

Selected for Consideration		Arc Wire Removal	Improved Reliability	Improved Safety/ Wire down	Improved Capacity	Cost Level	Execution Complexity
	1	Tree Trimming				Low	Low
	2	PTMM				Low	Low
	3	Arc Wire Removal				Medium	Low
	4	4.8kV Hardening				Medium	Low
	5	Pre-conversion				High	Medium
	6	Conversion				High	High
	7	Microgrids				Very High	Very High
	8	DERs				Medium	Medium
	9	Energy Efficiency				Low	Medium
	10	Storage				High	Medium

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2

3 **Q27. How does the 4.8kV Hardening Program compare to these alternatives in terms**
 4 **of investment required and expected benefits?**

5 A27. The Company presented Table 2 during the March 22, 2023, Technical Conference.
 6 This table shows the average investment required per mile, expected wire-down
 7 reduction, SAIFI⁴ reduction, CAIDI⁵ reduction, capacity impact, DER⁶ support, and
 8 execution complexity for the 4.8kV Hardening Program and its alternatives.

9

⁴ System Average Interruption Frequency Index (SAIFI) is an industry term and is the measurement of the average frequency of outage events any given customer on the Company's system would experience.

⁵ Customer Average Duration Interruption Index (CAIDI) is an industry term is a measurement of the average outage duration that any given customer on the Company's system would experience. CAIDI is the average outage restoration time for a customer outage.

⁶ Distributed Energy Resources (DER) are devices such as electric vehicle chargers and customer-owned solar panels.

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Table 2. Hardening Program Alternatives Comparison

	Avg. Cost per Mile (\$ thousands)	Wire down Reduction	SAIFI Reduction	CAIDI Reduction	Capacity Increase	Increased DER Usage	Execution Complexity	Potential Use Case
Arc Wire Removal	\$191	13%	22%	36%	No	No	Low	Lowest overall cost to remove arc wire
4.8kV Hardening	\$353	26%	44%	72%	No	No	Low	Highest benefit/cost for reliability improvement
Pre-conversion	\$1,700	90%	85%	85%	No	Yes	Medium	Provides step change in reliability performance
Conversion	\$2,700	90%	85%	85%	Yes	Yes	High	Best benefit/cost for significant capacity needs
Microgrids	\$14,600	90%	95%	95%	Yes	Yes	Very High	Potentially application for grid areas with critical reliability needs

2

3

4

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6

7

Q28. In addition to the analysis presented in the Technical Conference, what additional analyses for the 4.8kV Hardening Program were required in Order for Case No. U-21297 on December 1, 2023?

9

A28. The Commission ordered the Company to:

11

- Create a comprehensive, detailed, and longer-term plan for this work that includes an equity and safety analysis. The equity analysis must meet the following requirements include EJ analyses that provide community vulnerability gradations based on the MiEJScreen tool using 0% to 5%, 5% to

12

13

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- 1 10%, and 5% gradations all the way to 95%-100% of the MiEJScreen composite
- 2 score;
- 3 • Identify and qualify the potential hazard associated with other DPLD wire for
- 4 which DTE Electric has not provided documentation to date; and
- 5 • Show how equity has informed, and continues to inform, the Company's
- 6 actions with respect to 4.8kV Hardening and arc wire removal efforts.
- 7

8 **Q29. Has the Company completed the Environmental Justice (EJ) analyses as directed**

9 **by the Commission pertaining to the 4.8kV Hardening Program?**

10 A29. Yes. The Company has performed an EJ/equity analysis of the 4.8kV Hardening

11 Program by mapping its circuits to census tracts and cross-referencing with the

12 MiEJScreen tool. The MiEJScreen tool can be found at

13 <https://www.michigan.gov/egle/maps-data/miejscreen>.

14

15 As shown in Company Witness Kryscynski's testimony, 85% of all 4.8kV Hardening

16 Program investments from 2018-2025 impact communities that score between the top

17 80-100% MiEJ scores and are deemed vulnerable. More details of EJ/equity analysis

18 can be found in Company Witness Kryscynski's testimony.

19

20 **Q30. What progress has been made through year-end 2023 on the 4.8kV Hardening**

21 **Program?**

22 A30. The Company hardened approximately 373 miles in 2023 (Table 3) and has hardened

23 nearly 1,500 miles total from 2018-2023, which represents approximately 70% of the

24 total program scope. The Company has removed approximately 208 miles of arc wire

25 in 2023, and approximately 640 miles total from 2018-2023.

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1 A total of 307 circuits, representing approximately 196,000 customers in the city of
2 Detroit and surrounding areas, have been hardened by the program through year-end
3 2023.

4

5

Table 3. 4.8kV Miles and Arc Wire Removed through 2023

4.8kV Hardening	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Forecast	Total
Miles Hardened	105	128	209	202	475	373	1,492
Arc Wire Miles	59	52	105	64	155	208	643
Capital Investment (\$ thousands)	\$40,325	\$48,278	\$55,165	\$65,362	\$157,482	\$127,010	

6

7 **Q31. Why are there fewer miles of DPLD arc wire removed than miles hardened in**
8 **each year of the 4.8kV Hardening Program?**

9 A31. There are fewer miles of DPLD arc wire removed because the DPLD system does not
10 perfectly overlap DTE's distribution system. The Company has observed that there is,
11 on average, approximately twice as much DTE distribution wire on Detroit circuits as
12 there is DPLD arc wire.

13

14 **Q32. Does the 4.8kV Hardening Program target areas that do not contain DPLD arc**
15 **wire?**

16 A32. No. The 4.8kV Hardening Program does not target areas that do not contain DPLD arc
17 wire. The program targets all circuits on substations in areas known to contain DPLD
18 arc wire. However, it is often the case that a circuit does not contain as much DPLD
19 arc wire as DTE distribution wire. Because there is a fixed cost to planning work and

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1 mobilizing and demobilizing crews, the Company hardens the entire circuit so that all
2 customers in the area benefit from improved safety and reliability.

3

4 **Q33. What is the Company's plan to accelerate and complete the 4.8kV Hardening**
5 **Program?**

6 A33. The 2024 4.8kV Hardening workplan includes the hardening of approximately 145
7 circuit miles and removing 95 miles of arc wire. The Company has accelerated its plans
8 for removing arc wire in response to the direction provided by the Commission⁷. The
9 2025 4.8kV Hardening workplan includes hardening approximately 310 circuit miles
10 and removing 189 miles of arc wire. The 2026 4.8kV Hardening workplan includes
11 hardening approximately 116 circuit miles and removing 89 miles of arc wire. Table
12 4 shows the total planned circuit miles hardened and DPLD arc wire removed at the
13 conclusion of the 4.8kV Hardening Program in 2026.

14

15 A total of approximately 500 circuits, representing approximately 295,000 customers
16 in the city of Detroit and surrounding areas, will have been hardened at the conclusion
17 of the program.

⁷ In its December 1 Order in Case No. U-21297 the Commission stated, "completing this work is crucial to the residents and businesses located in areas that contain abandoned arc wire and the Commission agrees with the Staff that the removal of the arc wire should be going faster." (Order at pg. 93)

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1 **Table 4. Miles Hardened and DPLD Arc Wire Removed**

4.8kV Hardening	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	Total
Miles Hardened	105	128	209	202	475	373	145	310	116	2,063
Arc Wire Miles	59	52	105	64	155	208	95	189	89	1,015
Capital Investment (\$ thousands)	\$40,325	\$48,278	\$55,165	\$65,362	\$157,482	\$127,010	\$80,000	\$125,000	\$35,960	

2

3 **Q34. At the conclusion of 2026, how much of the DPLD arc wire that is co-located with**
4 **DTE equipment will be removed and how much will be remaining?**

5 A34. The Company had patrols conducted on its infrastructure in and around the City of
6 Detroit, and the final combined total of co-located DPLD arc wire identified was
7 approximately 1,268 miles (Table 5).

8

9 **Table 5. DPLD Arc Wire Removal 2018-2026**

Program	Arc Wire Miles
4.8kV Hardening	1,015
Remaining DPLD Arc Wire	253
Total	1,268

10

11 The Company estimates that approximately 1,015 of these DPLD arc wire miles will
12 be removed by the 4.8kV Hardening Program from 2018-2026 and that 253 miles of
13 DPLD arc wire will be remaining. The Company is continuing to evaluate its plans for
14 removing the remaining DPLD arc wire with the remaining miles being addressed with

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1 circuit conversion projects, and the possibility of further 4.8kV Hardening work to
2 ensure timely removal.

3

4 **Q35. Has the Company patrolled and catalogued all DPLD arc wire beyond that which**
5 **is co-located with Company infrastructure?**

6 A35. No. The Company has only patrolled and identified DPLD arc wire that is co-located
7 with Company equipment. The Company focused on cataloging co-located DPLD arc
8 wire because it represents a safety risk due its close proximity to energized wire and
9 has the potential to become energized as explained in Question 20.

10

11 **Q36. How does the 4.8kV Hardening Program benefit customers?**

12 A36. Results show that the 4.8kV Hardening Program has been effective in improving the
13 safety, reliability, and resiliency of circuits (Figures 3, 4, and 5).

14

15 The Company reviewed the three-year historic average for reliability and wire-downs
16 of the circuits hardened prior to the year hardened, and compared those numbers to the
17 year after hardening was complete. The Company also reviewed the three-year historic
18 average for reliability and wire-downs for circuits in the control group (which includes
19 the city of Detroit, and surrounding areas), that were not hardened in that time period.
20 The circuits included in this analysis were hardened in 2019, 2020, and 2021. Three
21 key metrics were reviewed to determine the effectiveness of the 4.8kV Hardening
22 Program: All-Weather System Average Interruption Frequency Index (SAIFI), System

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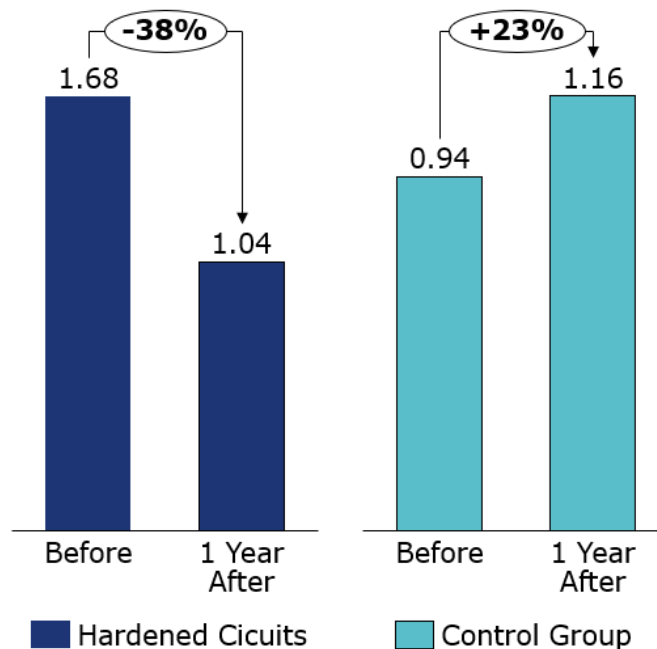
1 Average Interruption Duration Index (SAIDI) excluding major event days (Ex-
2 MED⁸s), and Wire-Downs.

3
4 All-Weather SAIFI reflects the frequency of the outage events experienced by
5 customers on the circuits regardless of weather conditions. SAIDI Ex-MEDs is an
6 indicator of the amount of time customers are without power excluding the most
7 significant weather event days, such as very large storms. The reduction in the number
8 of wire-downs is a measure of the safety improvements for the circuits that were
9 hardened.

10

11

Figure 3. 4.8kV Hardening All-Weather SAIFI



12

⁸ Major Event Days (MEDs) is an industry term that denotes a day in which a utility experienced a catastrophic event which exceeds reasonable design or operational limits of the electric power system and during which at least 10% of the customers within an operating area experience a sustained interruption during a 24-hour period. More information about MEDs and their calculation can be found at <https://cmte.ieee.org/pes-drwg/wp-content/uploads/sites/61/2003-01-Major-Events-Classification-v3.pdf>.

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Figure 3 displays the All-Weather SAIFI improvement of hardened circuits vs. the control group; the customers on hardened circuits experienced a 38% improvement in All-Weather SAIFI, while the control group circuits degraded by 23%, resulting in a net improvement of 61% for hardened circuits.

Figure 4. 4.8kV Hardening SAIDI excluding MEDs

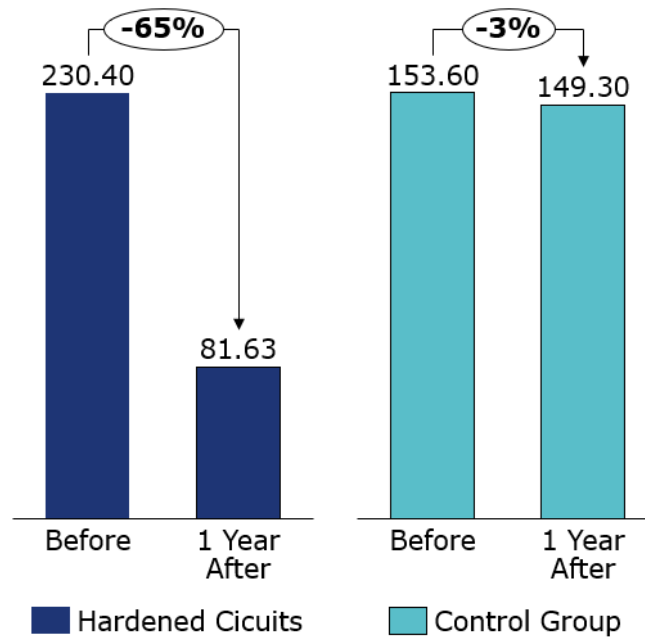
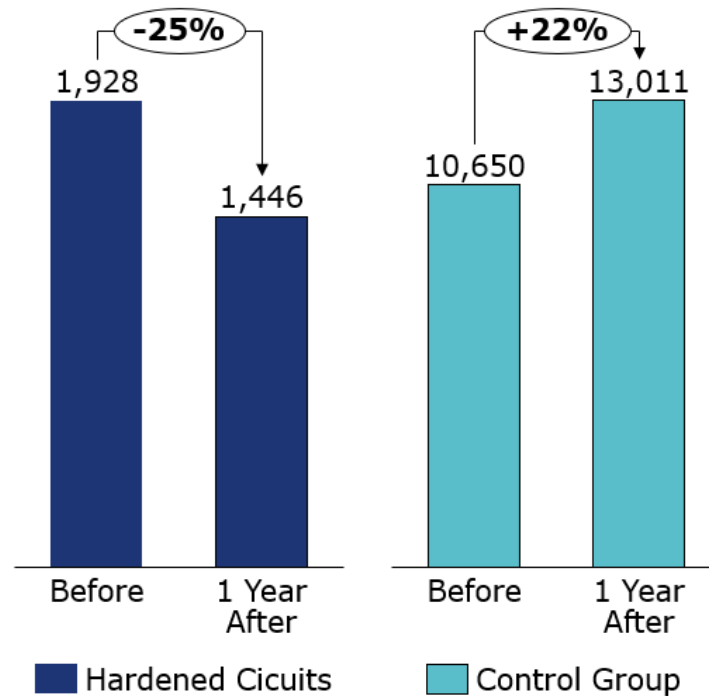


Figure 4 displays the SAIDI Ex-MEDs improvement of hardened circuits vs. the control group; the customers on hardened circuits experienced a 65% improvement in SAIDI Ex-MEDs, while the control group improved by 3% improvement, resulting in a net improvement of 62% for hardened circuits.

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Figure 5. 4.8kV Hardening Wire-downs



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Q37. Why does the 4.8kV Hardening Program perform deconductoring on some circuits?

10

11

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14

A37. As stated in Company Witness Deol's testimony, the customer benefits of deconductoring are the elimination of potential wire-downs by removing overhead lines that are not fully utilized and the elimination of potential power outages caused by those lines failing or being damaged. The primary drivers of the 4.8kV Hardening Program are to remove DPLD arc wire to reduce wire-downs and improve safety, and

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1 to evaluate the poles and pole-top equipment for replacement to balance the crossarms
2 and improve reliability. As such, deconductoring fits into the scope of the 4.8kV
3 Hardening Program.

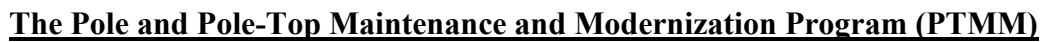
4

5 **Q38. How can customers stay informed about 4.8kV Hardening work being performed**
6 **in their area?**

7 A38. Customers interested in seeing if 4.8kV Hardening work is being performed in their
8 respective area can visit the Company's external website at
9 [https://dte.maps.arcgis.com/apps/webappviewer/index.html?id=5d9dc2eb1244456189](https://dte.maps.arcgis.com/apps/webappviewer/index.html?id=5d9dc2eb124445618959ce788086e00e)
10 [59ce788086e00e](https://dte.maps.arcgis.com/apps/webappviewer/index.html?id=5d9dc2eb124445618959ce788086e00e). These maps are regularly updated to inform our customers of the
11 reliability work the Company is performing on their behalf, to visually display work
12 completed in the last 6 months, and to show work scheduled to be completed within
13 the next 12 months. Please note that the 4.8kV Hardening and PTMM Programs are
14 called "Upgrading Existing Infrastructure" in the map provided on this website. This
15 map also shows Tree Trimming, Customer Excellence (called "Rapid Response"), and
16 Circuit Conversion (called "Rebuilding Significant Portions of the Grid"). A current
17 example of this map showing only the Upgrading Existing Infrastructure layer can be
18 seen in Figure 6.

19

Figure 6. Upgrading Existing Infrastructure Map



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1 **Q39. What is the Pole and Pole-Top Maintenance and Modernization (PTMM)**
2 **Program?**

3 A39. The PTMM Program is the Company's program to inspect and maintain overhead
4 distribution equipment, in support of improving the system reliability and resilience to
5 weather, storms, and tree-related events as described below. Formerly called the Pole-
6 Top Maintenance (PTM) Program, the modernization aspect was included in late 2019,
7 and the program renamed to PTMM to reflect updated standards for inspection
8 methods, and updated standards for equipment, and materials.

9

10 **Q40. What are the drivers of the Company's PTMM Program?**

11 A40. Approximately 70% of DTEE's infrastructure is overhead. Overhead equipment
12 failures cause approximately 25% of all outages customers experience during all
13 weather conditions, and over 30% of all outages customers experience excluding Major
14 Event Days (MEDs). Poles and pole-top equipment are some of the most critical and
15 visible parts of the distribution and subtransmission grid, and are continually exposed
16 to harsh conditions (e.g., tree strikes, ice, heat, rain, lightning, sunlight, and wind),
17 causing them to degrade, weaken, and fail over time. Examples of equipment damage,
18 also called inspection defects, are shown in Figure 7.

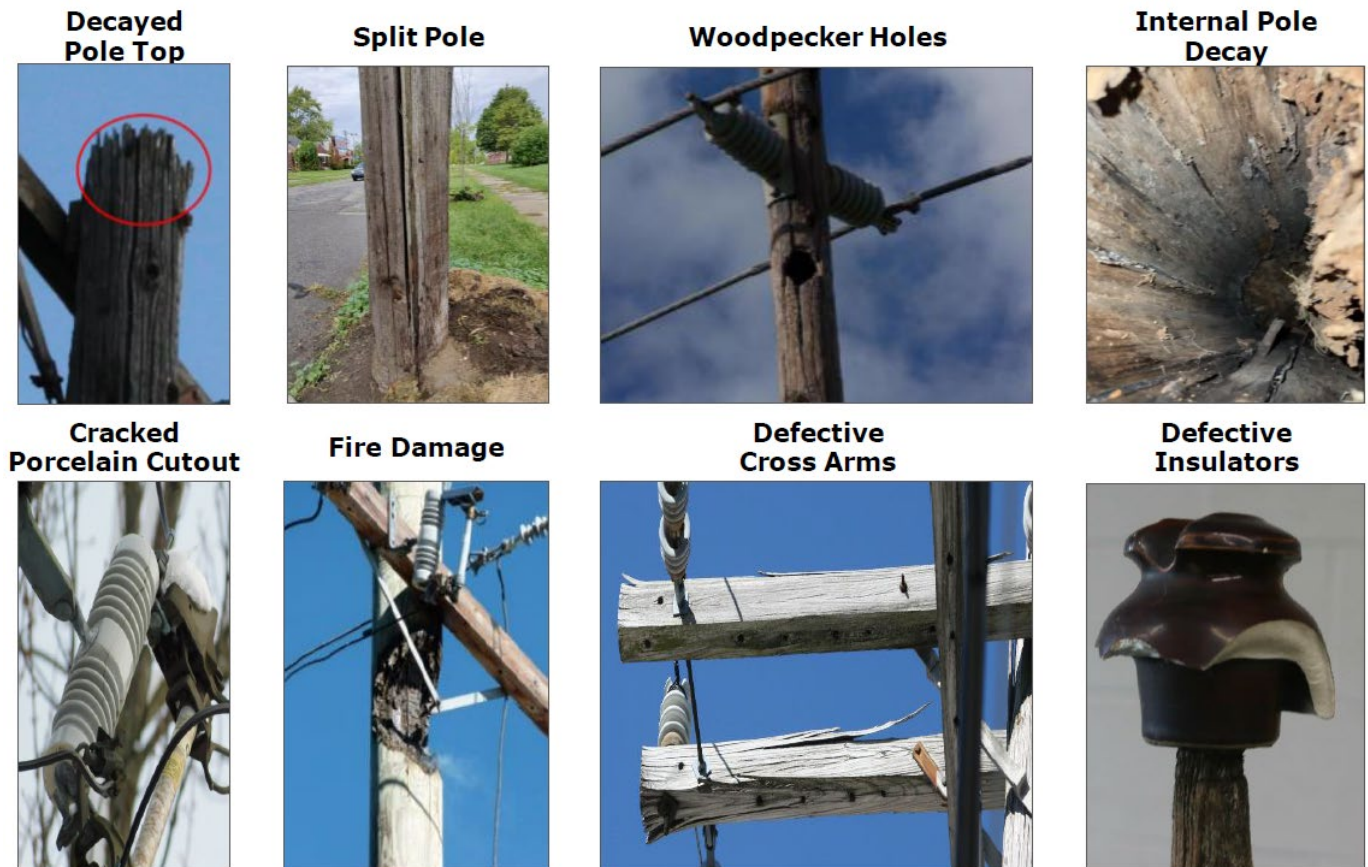
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Figure 7. Pole and Pole-Top Defect Examples

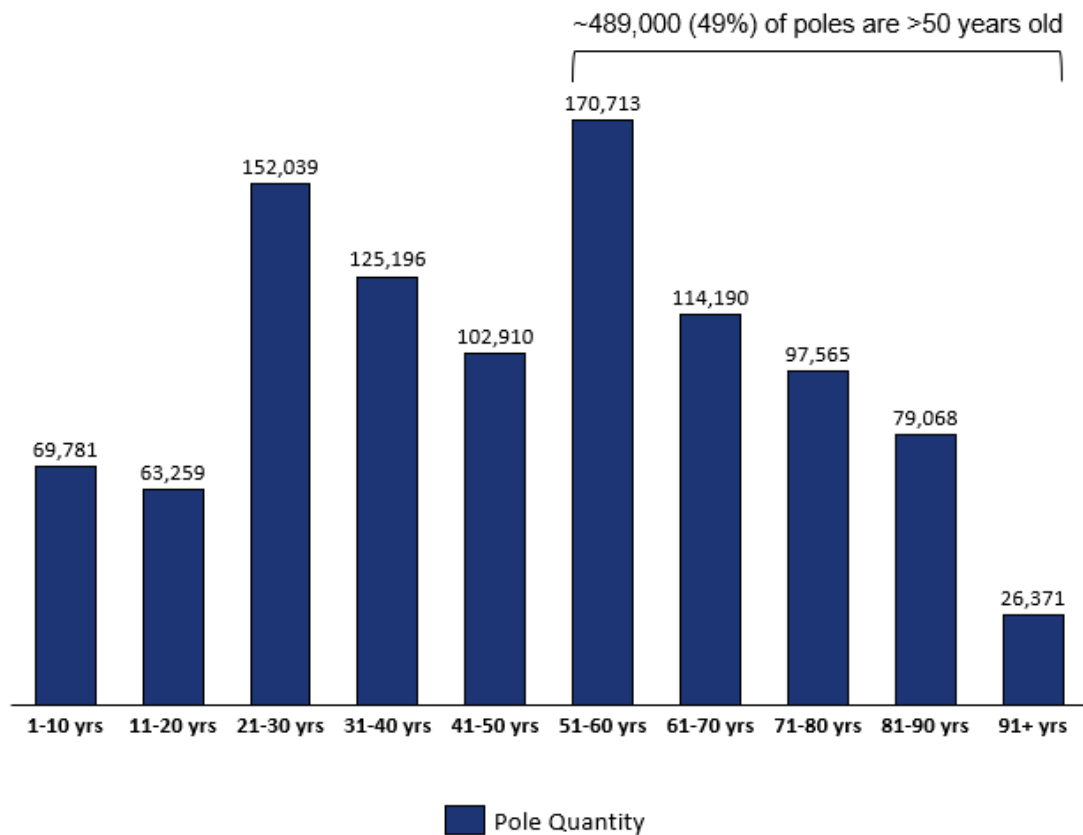
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The Company has approximately 31,000 miles of overhead distribution and subtransmission lines, collectively containing approximately one million Company-owned wood poles and associated pole-top equipment. Utility poles have a useful life expectancy of approximately 40-50 years and have elevated failure risk as they age beyond their useful life. Useful life is a standard industry term that does not represent the actual life of an asset, but rather the age at which an installed asset is expected to experience increasing failure rates and deliver reduced performance, such that it is often more prudent to replace than to continue to repair and maintain. Figure 8 displays DTEE owned utility pole counts currently in use in the system by age range.

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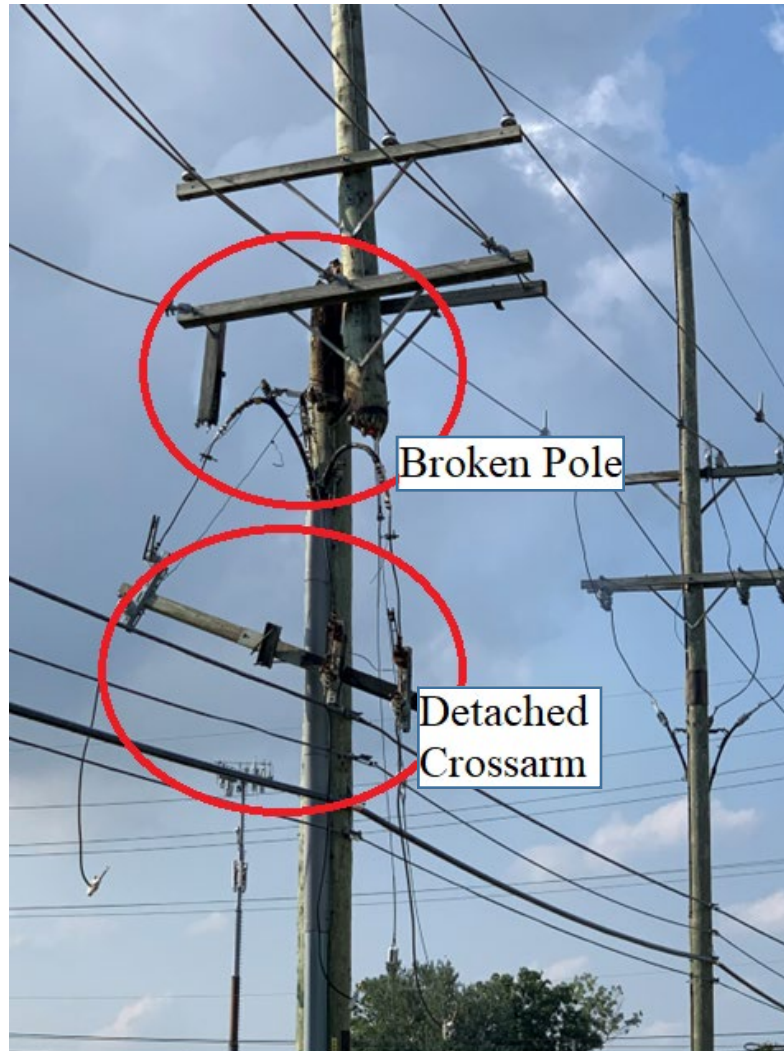
Figure 8. DTEE Poles by Age



Aging poles and pole-top equipment increase the risk of overhead equipment failures, which can subsequently cause outages. In addition to outages, examples of incidents that can occur in the event of pole and pole-top equipment failures include property damage, fires, and traffic accidents. Additionally, long and costly customer outages can result when this equipment fails unexpectedly from tree impacts or from other causes. Figure 9 displays an example of a pole-top equipment failure.

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Figure 9. Overhead Pole-top Failure – Example



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Q41. What benchmarking has the Company performed on PTMM?

9

A41. The Company has performed three benchmarking studies in 2018, 2021, and 2022 on the PTMM practices at fifteen peer utilities. While these studies varied in what portion

10

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1 of the PTMM programs were in focus, the Company found that all of the utilities had
2 some sort of maintenance program to proactively address defective pole and pole-top
3 assets in the field before they fail. Additionally, the benchmarking identified that the
4 Company's inspection standards, including a 10-12 year pole inspection cycle, are in
5 line with other utilities. Table 6 displays the Pole Inspection and Pole-Top Inspection
6 cycle identified in seven of the utilities located in the Northeast and Midwest, indicating
7 that most utilities operate on a 10-year (or less) cycle time for pole inspections and
8 construction, and a 5-year cycle time for pole-top inspections and construction.

9

10

Table 6. PTMM Benchmarking

	Company 1 Northeast	Company 2 Northeast	Company 3 Midwest	Company 4 Midwest	Company 5 Midwest	Company 6 Midwest	Company 7 Midwest
Pole Inspection Cycle	10 years	5 years	10 years	10 years	10 years	12 years	8-12 years
Pole-Top Inspection Cycle	4 years	5 years	5 years	5 years	5 years	12 years	8-12 years

11

12 In addition to industry utility benchmarking, the Company consulted multiple industry
13 expert publications and guidelines when developing and updating its PTMM program
14 policies, as noted in Table 7.

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Table 7. Industry Standards & Guidelines**Summary of Industry Standards and their Application in DTE's Pole Inspection Specification**

Report	DTE Application
IEEE National Electric Safety Code (NESC)	Per the NESC standard, 67% pole strength is used as the threshold to accept or reject a pole in DTE's specification
Rural Utilities Services UEP Bulletin 1730B-121	- The report outlines the frequency of pole inspection cycle of 10 years in Michigan - DTE's specification leveraged the guidelines in this report for other conditions aside from pole strength that could justify rejection of a pole such as severe woodpecker hole damage and split top - DTE also leveraged this report for classifying a rejected pole as a restorable reject where a remedial treatment is applied or a non-restorable reject where the pole is replaced
Wood Pole Maintenance Manual (2012) Oregon State Forest Research Lab	- The Oregon State Forest Research Lab report references the NESC safety standard for pole strength and UEP Bulletin pole classifications as described above, further validating the practice as industry standard - The report provides a sample pole inspection procedure that details various methods and equipment to inspect poles - Methods include excavation, partial excavation, sounding, boring, shell thickness measurements for evidence of decay, and applying remedial treatment to reinforce poles - DTE's pole inspection specification leverages the methods outlined in the report
American Wood Protection Association (AWPA) M13-07 Guidelines for a Pole Maintenance Program	- The AWPA report details methods for inspection, similarly to the Oregon State Forest Research lab report, further validating the practices as industry standard - The report includes additional consideration in the design of a pole inspection program, such as workforce/personnel and data management

2

3 **Q42. How has this benchmarking and industry research impacted the way the**
4 **Company manages its PTMM program?**

5 A42. The Company has continued to use internal expertise, combined with benchmarking
6 and industry standards, to develop and update the PTMM program and associated
7 specifications to ensure best practices are implemented timely to improve reliability for
8 customers. Based on these findings, the Company is aspiring to implement a PTMM
9 program capable of inspecting, and completing the required construction, for poles on
10 a 10-year cycle and pole-top equipment locations on a 5-year cycle to match the
11 industry best practice identified in the benchmarking efforts discussed above.

12

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1 **Q43. What is the scope of DTEE's PTMM Program?**

2 A43. The PTMM Program inspects all wood poles and all pole-top equipment on distribution
3 and subtransmission overhead circuits, and identifies and replaces poles and pole-top
4 equipment that fails inspection. The PTMM Program scope includes all overhead
5 circuits except those included in the 4.8kV Hardening Program.

6

7 The PTMM Program's work activities are described below:

8 1. Poles are inspected for damage that will undermine structural integrity.

9 (a) Poles younger than 20 years are visually inspected above grade.

10 (b) Poles older than 20 years are visually inspected and excavated below grade
11 level and physically tested.

12 2. Poles which fail inspection are treated and reinforced, or replaced.

13 3. Trees are trimmed, as required, to support construction activities.

14 4. Pole-tops and pole-top equipment are visually inspected for damaged and/or
15 defective equipment.

16 5. Pole-top equipment which fails inspection is replaced. Examples include:

17 (a) Damaged wooden crossarms are replaced with fiberglass crossarms.

18 (b) Damaged/defective porcelain cutouts are replaced with polymer cutouts.

19 (c) Damaged/defective porcelain insulators are replaced with polymer
20 insulators.

21

22 Figures 10 and 11 show the improvements made before and after PTMM is complete
23 at a pole-top location.

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Figure 10. Before PTMM – Example



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Figure 11. After PTMM – Example



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6

Q44. Does the PTMM Program replace poles and pole-top equipment based solely on age?

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1 A44. No. The PTMM Program inspects poles and pole-top equipment and only replaces
2 those which fail inspection.

3

4 **Q45. How does the Company decide whether a pole should be reinforced or replaced?**

5 A45. The Company's pole inspection process is shared in Exhibit A-23, Schedule M9 Pole
6 Specification. This exhibit contains the inspection process, pole data collected and
7 calculated, and the decision criteria for determining whether a pole should be treated,
8 reinforced, or must be replaced.

9

10 The following data is collected on poles older than twenty years: measured
11 circumference at groundline, measured shell thickness at groundline, minimum
12 measured pole circumference below groundline, measured external pole decay,
13 measured internal pole decay, and orientation of the pocket in regard to line of lead.
14 These data points are used to calculate 1) groundline effective circumference, 2)
15 percent remaining pole strength, and 3) groundline condition of the pole. Figure 12
16 shows pole testing and inspection processes.

17

18 As a result of these inspections and calculations, poles are classified as acceptable,
19 restorable rejects, or non-restorable rejects. Acceptable poles may be treated internally
20 and/or externally depending on the specific circumstances. Restorable reject poles may
21 be treated and/or reinforced but must be replaced instead if they meet the criteria listed
22 below that disqualify them from reinforcement. Non-restorable reject poles are
23 replaced.

24

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1 All poles below 100% strength are candidates for internal treatments unless they must
2 be replaced. Internal treatments are designed to protect the heartwood of the pole
3 against fungus and insect attacks but are not used on poles that do not have measurable
4 evidence of decay, voids, infestations, are near water, at sites with well water, on
5 schoolgrounds, farmland, or vegetable gardens.

6

7 All acceptable and restorable reject poles (except those that must be replaced due to the
8 criteria listed below that disqualify from reinforcement) that were fully excavated are
9 treated with exterior groundline treatment. External groundline treatments are designed
10 to protect the outer shell of the pole at groundline and reduce the loss of residual
11 circumference due to decay. Poles that are 65 feet or shorter and are measured to
12 determine if they have 67-99% of their strength remaining and are therefore deemed
13 acceptable and are candidates for external groundline treatments. Poles that are 70 feet
14 or taller and are measured to determine if they have 75-99% of their strength remaining
15 and are therefore deemed acceptable and are candidates for external groundline
16 treatments.

17

18 The Company's pole inspection standard is in line with the Institute of Electrical and
19 Electronics Engineers (IEEE) National Electrical Safety Code standard that poles 65
20 feet or shorter fail inspection if they are below 67% of their original strength, and must
21 be treated, reinforced, or replaced. Poles that are 70 feet or taller fail inspection if they
22 are below 75% of their original strength, and must be treated, reinforced, or replaced.

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- 1 Poles that are 65 feet or shorter and are measured to have 15-66% of their strength
2 remaining, are deemed restorable rejects. Poles that are 70 feet or taller and are
3 measured to have 15-74% of their strength remaining, are deemed restorable rejects.
4
- 5 All poles of any height that are measured to have less than 15% of their strength
6 remaining are deemed non-restorable rejects.
7
- 8 The following criteria make a pole ineligible for reinforcement per the Company's
9 standards:
- 10 • An excessively leaning pole (e.g. a 40-foot pole leaning 7 inches or
11 greater at a height of 5 feet above grade) cannot be reinforced unless it
12 is it possible to straighten;
 - 13 • A pole damaged by carpenter ants;
 - 14 • Poles supporting wire crossing railroad tracks or highways
 - 15 • Poles that were treated in the past with "Cellon" processes
 - 16 • Poles cannot be reinforced under the following conditions:
 - 17 - Poles in non-testable locations and > 50 years old
 - 18 - Poles with less than 15% of their original strength
 - 19 - Poles identifiable as restorable candidates but not pass above
20 grade inspection
 - 21 - Poles with an average sound shell thickness of less than 1"
 - 22 • Non-DTEE-owned poles;
 - 23 • Poles smaller than class 5 (e.g. 6, 7 ,8, 9);
 - 24 • DTEE Riser poles;
 - 25 • Poles within 100' of school property or water locations;

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- 1 • Poles that are not candidates for remedial treatments;
- 2 • Electrical cable poles; and
- 3 • DTEE owned poles with no electrical overhead conductor
- 4
- 5 Additionally, poles that fail visual inspection due to the following cannot be reinforced:
- 6 • Shell rot or surface rot decay outside ground line area
- 7 • Woodpecker holes around or below the hardware that appear hollow
- 8 • Split tops that affect the integrity of bolts or equipment
- 9 • Split tops that do not have a bolt running perpendicular to the split
- 10 • Decayed tops with decay and crowning close to hardware
- 11 • Spur cut that results in 1” of the pole outer shell being removed
- 12 • Compression wood damage resulting in horizontal cracking that
- 13 penetrates 1” deep into the shell and covers a large surface
- 14
- 15 Poles that fail inspection and are not eligible for reinforcement based on the criteria
- 16 listed above are replaced.
- 17

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Figure 12. Physical Pole Testing and Inspection

PTMM Pole Testing and Inspection Process

- 1** Sounding - hammer used to detect internal decay



- 2** Partial excavation checks for external decay



- 3** Full excavation used once decay is found



- 4** Boring - drill at decay points to take internal measurements



These three steps, recognized as industry best practice, are critical to ensure accurate identification of defective poles and address associated safety and resiliency concerns

- 5** Internal and external measurements



- 6** Pole strength calculated to accept or reject pole

StrengthCalc	
Orig G/L Circum	34
SR Circ-This Cycle	32
Exposed Pockets	No Exposed Pock.
Enclosed Pockets	☒
Mechanical Damage	No Mech Damage
Orient: +45	
Shell	1
Width	4
Tot Dpth	4
Eff Circ:30.8 - Rem Str:75	

(A)dd + (R)emove -
(C)Item Item(x)
(E)dit Item (N)ext

- 7** Worksite preserved



- 8** Poles tagged with inspection company, year and wood preservatives applied



2

3 **Q46. How does the Company decide whether pole-top equipment should be replaced?**

4 **A46.** The Company's pole-top inspection process is shared in Exhibit A-23, Schedule M10
5 Pole-Top Specification.

6

7 In general, the following items are examples of what is replaced if they are found to be
8 environmentally hazardous, broken, cracked, decayed, melted, burned, arcing, or
9 missing:

- 10
- Transformers
 - Cutouts
- 11

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- 1 • Crossarms
- 2 • Braces
- 3 • Brackets
- 4 • Insulators
- 5 • Arrestors
- 6 • Hot taps
- 7 • Ground wire
- 8 • Ground wire molding
- 9 • Conductors
- 10 • Spools
- 11 • Hardware (nuts, bolts, etc.)

12

13 **Q47. Did the Commission address the PTMM Program in Case No. U-21297?**

14 A47. The Commission approved cost recovery for PTMM in Case No. U-21297 at an
15 investment level of \$63.45 million annually, however they expressed concerns
16 regarding the clarity around recent increases in investment levels.

17

18 **Q48. Has the MPSC provided guidance on an appropriate cycle for pole inspections in**
19 **the past?**

20 A48. Yes. On November 20, 2009, the Michigan Public Service Commission Staff published
21 the “Utility Pole Inspection Program Investigation Staff Report”. In that report, the
22 Staff recommended that DTEE achieve a 10-12 year pole inspection cycle frequency
23 to correlate with the standard recommended by the USDA Rural Utility Service for
24 Michigan’s decay zone. The Staff also requested DTEE to provide a brief Pole
25 Inspection Report to Staff each year by September 1, beginning in 2010.

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1 **Q49. Has the Company provided annual pole inspection reports to the MPSC Staff?**

2 A49. Yes, the Company has provided pole inspection reports to Staff annually since 2010.

3

4 **Q50. What did the Commission order regarding PTMM inspection reporting and**
5 **benefit cost analysis in Case No. U-21297?**

6 A50. The Commission ordered the Company to prepare an annual pole and pole-top
7 inspection report, that is similar to the Company's Annual Tree Trimming Report, and
8 to complete a benefit cost analysis of the program.

9

10 **Q51. Is the Company preparing an annual PTMM report to comply with the**
11 **Commission's directive described above?**

12 A51. Yes, at the time this testimony was being prepared, the data for the required report was
13 being assembled.

14

15 **Q52. Has the Company performed a benefit cost analysis (BCA) for PTMM to comply**
16 **with the Commission's directive as described above?**

17 A52. Yes. The Company completed a BCA, as directed, in February 2024. The Company
18 collaborated with an external consulting firm to create a BCA for PTMM based on a
19 methodology utilized by other utilities in other states (such as IN, OH, IL, MD, FL, and
20 OK). This BCA utilized a bottoms-up, asset-based approach to capture the present
21 value of the benefits over a 40-year study period, compared to the upfront investments
22 to implement the PTMM program, creating a benefit cost ratio by circuit. For this
23 statistical model, the benefits are calculated as the avoided cost of emergent reactive
24 events caused by running equipment to failure, and includes the use of the LBNL ICE
25 calculator to model customer impacts from these outages. The "upfront investments"

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are calculated by totaling the investment forecasted to properly complete pole and pole-top inspections, pole remediation and reinforcements, and pole and pole-top equipment replacements required per the inspection process. The overall average system benefit cost ratio for the system was calculated at 3.8, meaning if PTMM could be conducted on 100% of the Company's distribution grid, the benefits realized by the customers for completing PTMM would be 3.8 times greater than the benefits realized if the Company decided to run all poles and pole-top equipment to failure. The PTMM BCA Whitepaper is included to this instant case as Exhibit A-23, Schedule M13.

Q53. What changes has the Company made to its PTMM program in recent years?

A53. The Company's PTMM program has gone through a transformation over the past few years to support a more resilient overhead infrastructure, including alignment with the industry standards discovered through benchmarking activities. The first improvements the Company implemented followed the first set of benchmarking in 2018 and 2019, and included updating the pole inspection process (as defined above), and transitioning the previous Pole Top Maintenance (PTM) Program to the Pole and Pole-Top Maintenance and Modernization Program. The addition of "Modernization" simply meant that when a pole, or piece of pole-top equipment failed inspection, the Company would no longer replace like-for-like, rather the equipment would be replaced with the equipment that met the new, higher-level specification to incorporate more modernized equipment into the field.

The second set of improvements were implemented in 2021 and 2022, and included only using PTMM inspections solely (and no longer utilizing Joint Use inspections) to meet the 10-12 year cycle, and assembling a new team to enhance the PTMM program

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1 management including more rigorous quality reviews of work completed and
2 implementing process improvements based on industry standards learned through
3 benchmarking. The decision to no longer utilize Joint Use inspections in the PTMM
4 program was due to the fact that they were less rigorous than PTMM inspections and
5 focused on telecommunications equipment and clearances, rather than focused on the
6 Company's pole-top equipment, and were no longer suitable to use for PTMM.

7
8 The third set of improvements were implemented in 2023, and could be grouped into
9 two categories – 1) inspection quality control, and 2) process improvements. First, the
10 inspection quality control improvements were implemented prior, during, and post
11 inspections to ensure adherence to DTEE's PTMM specification. They include: hands-
12 on training required for all inspectors including a knowledge test; inspectors are
13 equipped with picture-based field manuals to help identify defective equipment; DTEE
14 field leads provide daily guidance to inspectors and perform quality checks on work
15 completed; and more than 50% of all job packages receive a field audit from a third-
16 party to ensure accuracy. Second, the PTMM program team performed multiple
17 process improvements including developing a Geographic Information System (GIS)
18 based application (app) used to digitize inspection results, and streamline the
19 remediation of defective assets. Now, when the inspector submits their inspection
20 findings into the app, the team processes a completed construction job package that
21 includes a material list, compatible units (which define the specific work to be
22 completed), and four pictures of each work location. This allows the PTMM program
23 management team real-time visibility into field activities, improved coordination of
24 resources, and reduces the cycle time from inspection to construction completion.

25

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1 **Q54. What has led to the increase in PTMM investments in recent years?**

2 A54. Historically, the PTMM program has measured number of poles inspected, number of
3 poles replaced, number of poles reinforced, and total line miles modernized (meaning
4 pole-top equipment locations where construction is complete to remediate failed
5 equipment identified through the inspection process). The largest cost driver of the
6 PTMM Program is the increased quantity of defective pole and pole-top locations
7 identified through the inspection process.

8

9 As seen in Table 8 and Table 9 below, the stringent adherence to PTMM standards and
10 enhanced quality controls has led to an increased volume of defects identified and
11 remediated on our system. In 2022 and 2023, the program increased defective pole
12 replacements by over 2,900 poles per year driven by 1) higher pole reject rates, 2)
13 higher levels of PTMM inspections (not including Joint Use), 3) and a focus on backlog
14 reduction. During the same timeframe, the program increased defective pole-top
15 equipment replacements by approximately 5,500 pole top locations per year driven by
16 1) higher pole-top defect rates based on updated inspection standards, 2) enhanced
17 quality control (training, field audits, etc.), 3) higher circuit miles being addressed. In
18 this instant case, the planned investment increases per circuit mile in the PTMM
19 Program are based off the higher pole and pole-top equipment location failure rates that
20 have been recorded since improvements were made to the program.

21

Table 8. PTMM – Pole Defects per Mile

	2019	2020	2021	2019-2021 Average	2022	2023
Poles Replaced per Circuit Mile	1.3	1.0	0.7	1.0	2.9	3.7

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Table 9. PTMM – Pole-Top Defects per Mile

	2019	2020	2021	2018-2021 Average	2022	2023
Pole-Top Locations per Circuit Mile	1.2	1.2	2.1	1.5	3.6	12.7

2

3 **Q55. What work did the PTMM program complete in 2023?**

4 A55. The PTMM program completed construction on 1,418 circuit miles which included
 5 approximately 9,500 pole-top equipment locations, and replaced 3,814 poles.
 6 Additionally, the program completed inspections on 12,650 poles.

7

8

Table 10. Historical PTMM Work Units Performed

	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Forecast
Circuit Miles	1,027	1,496	1,541	1,562	1,418
Poles Replaced	1,333	1,431	1,016	4,537	3,814
Poles Reinforced	2,717	27	109	1,116	150
Pole Top Locations Replaced	1,232	1,795	3,236	5,621	9,500
Capital Investment (\$ thousands)	\$26,892	\$36,364	\$31,647	\$80,879	\$79,075

9

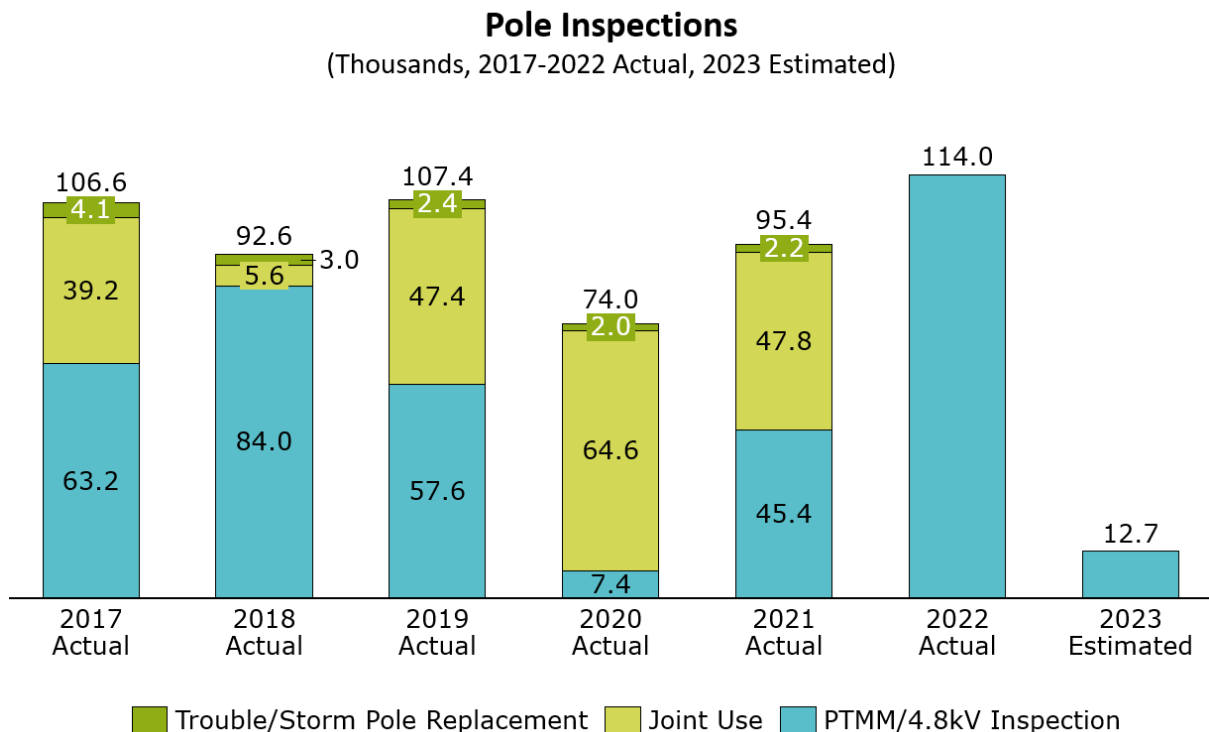
10 **Q56. Why did the PTMM program complete fewer inspections in 2023 than in prior**
 11 **years?**

12 A56. Prior to 2023, the Company had been consistently meeting the expectation of inspecting
 13 poles on a 10-12 year cycle following the MPSC direction discussed above (Figure 13).

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1 However, the Company was unable to complete the required construction activities to
2 remediate the failing poles and pole-top equipment locations identified in a timely
3 manner with its total investment, thus a backlog of construction work was created.
4 Additionally, as the Company stopped utilizing Joint Use inspections in 2022, and only
5 used PTMM Program inspections, there was an increase in the number of poles and
6 pole-top equipment locations that failed inspection per circuit mile. This compounded
7 the issue and grew the backlog of work which failed inspection and required
8 construction. At the beginning of 2023, the Company had a total of 4,695 poles and
9 14,654 pole-top equipment locations that failed inspection, and made the strategic
10 decision to pause most new inspections, and focus efforts on completing the required
11 construction already identified.

12 **Figure 13. Pole Inspections 2017-2023**



13

14 **Q57. What is the status of the PTMM work ready for construction?**

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1 A57. As of January 1, 2024 the Company had 3,744 poles and 9,353 pole-top locations that
2 failed inspection and still require construction to be completed.

3

4 **Q58. Is the Company planning to complete inspections in 2024 and 2025 consistent with**
5 **the 10-12 year inspection cycle previously completed?**

6 A58. Not in this instant case. Since the customer only benefits from the PTMM program
7 once the construction is complete, and the Company does not want to create a situation
8 where the backlog of work begins to rise above approved investment levels, DTEE has
9 made the strategic decision to only conduct pole and pole-top equipment location
10 inspections on the amount the PTMM program is funded to complete the associated
11 construction activities. Given the current approved funding levels for PTMM, and the
12 pole and pole-top equipment location failure rates, the Company will not be able to
13 meet the 10-12 year pole inspection cycle in this instant case. However, the Company
14 is planning to continue to seek approval to increase PTMM investment levels in this
15 instant case and beyond, to allow a return to a 10-year pole inspection and construction
16 cycle, and the 5-year pole-top equipment location inspection and construction cycle to
17 match the industry standard programs identified in benchmarking activities. The
18 specific inspection plans for 2024 and 2025 are discussed further below.

19

20 **Q59. How has the PTMM Program changed the way it prioritizes circuits for 2024?**

21 A59. Due to the increase in capital investment required per circuit mile discussed above, and
22 the supported annual funding for PTMM at \$63.45 million, the Company has created a
23 method of prioritizing work based on the worst reliability circuits for 2024.

24

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1 This analysis includes categorizing circuits into four tiers, based on the frequency and
2 magnitude of reliability issues customers experience (Table 11), where Tier 1 are the
3 worst performing circuits and Tier 4 are the best performing circuits.

4

5

Table 11. Circuit Reliability Tiers

Circuit Tier	Prioritization Criteria	Circuit Count	Customer Count (thousands)
Tier 1	AW SAIFI or AW SAIDI in worst 500 circuits for 3+ years (2019-2023)	365	426
Tier 2	AW SAIFI or AW SAIDI in the worst 800 circuits for 3+ years (2019-2023)	322	389
Tier 3	All Circuits not classified as Tier 1, 2, or 4	461	491
Tier 4	AW SAIFI or AW SAIDI in the best 1,000 circuits for 3+ years (2019-2023)	1,118	880
Total		2,266	2,186

6

7 Circuits that are ranked in the worst 500 performing circuits (based on All Weather
8 (AW) SAIFI and AW SAIDI) from three prior years are categorized as Tier 1, and the
9 highest reliability risk. Circuits that are ranked in the worst 800 performing circuits
10 from three prior years, are categorized as Tier 2, and the second highest reliability risk.
11 Circuits that are ranked in the best 1,000 performing circuits from three prior years are
12 categorized as Tier 4, and all remaining circuits are categorized as Tier 3.

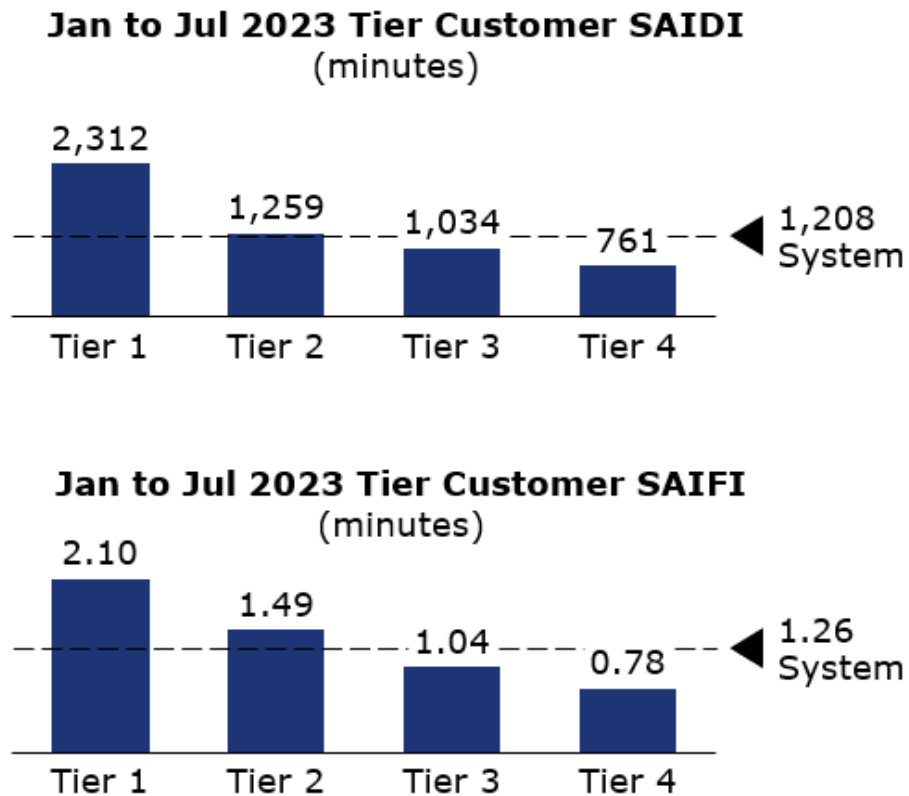
13

14 This method of determining reliability tiers was validated using January through July
15 2023 reliability data as seen in Figure 14, where the results of the analysis show that

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1 circuits ranked as Tier 1 and Tier 2 have worse AW SAIFI and AW SAIDI performance
2 than Tiers 3 and 4 and the system-wide average.

4 **Figure 14. Distribution Circuit Reliability Tier Comparison**



5

6 Once the tiers were identified, the Company created the 2024 construction plan,
7 optimizing the selection of Tier 1 and Tier 2 circuits, the work that was already in
8 process of construction, and distributing the workload throughout the service territory.
9 When the BCA discussed above was completed, the Company validated the 2024
10 workplan had a high benefit cost ratio.

11

12 **Q60. How is the PTMM Program prioritizing circuits for 2025?**

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1 A60. The Company selected circuits for 2025 based on the benefit cost ratios calculated by
2 the PTMM BCA model and then further prioritized based on reliability risk tier to
3 ensure they are reasonable and prudent for inclusion in the workplan.
4

5 **Q61. Is the Company still working towards a 10-year pole and 5-year pole-top**
6 **equipment location inspection and construction cycle in the PTMM program?**

7 A61. Yes. However, while the Company is unable to execute a 10-year pole and 5-year pole-
8 top cycle in the short term based on current inspection failure rates being realized
9 through the PTMM inspection process, the Company plans to increase PTMM
10 investments to reach a 10-year pole and 5-year pole-top cycle. As described above, the
11 Company used the reliability tier model, and other operational data, to create the 2024
12 workplan based on the current approved investment level, and utilized the BCA output
13 to validate the reliability benefit for the customers included on the selected circuits. In
14 this instant case, the Company is requesting approval to increase investment in PTMM
15 in 2025 to \$121 million, still utilizing the reliability tier model and BCA output, to
16 select the optimal mix of circuits to improve customer reliability. The Company has
17 plans to continue to seek increases in investment levels in the PTMM program,
18 consistent with PTMM inspection failure rates, beyond this instant case, to ultimately
19 reach a 10-year pole, and 5-year pole-top equipment location inspection and
20 construction cycle matching industry standard levels identified through benchmarking
21 efforts discussed above.
22

23 **Q62. What is in the Company's 2024 and 2025 PTMM workplan?**

24 A62. Based on a planned investment level of \$63.4 million consistent with the order in Case
25 No. U-21297, the 2024 PTMM workplan includes replacing poles and pole-top

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1 equipment on approximately 750 circuit miles. This translates to replacing
2 approximately 1,700 poles, and replacing pole-top equipment which has failed
3 inspection at approximately 8,655 pole-top equipment locations. In addition, the
4 PTMM program will inspect approximately 39,250 poles to support the workplan for
5 future investment plans.

6

7 In this instant case, the Company is requesting approval to invest \$121 million in the
8 PTMM program to fund the 2025 workplan to replace poles and pole-top equipment
9 on approximately 1,100 circuit miles. This translates to replacing approximately 3,965
10 poles, and replacing pole-top equipment that has failed inspection at approximately
11 13,800 locations. In addition, the PTMM program will inspect approximately 53,500
12 poles to support the workplan for future investments. The activity after the projected
13 test year is covered in the IRM section of this testimony.

14

15 **Table 12. PTMM 2024-2025 Workplan**

	2024	2025
Circuit Miles	750	1,100
Poles Replaced	1,700	3,965
Poles Reinforced	100	200
Pole-Top Locations Replaced	8,655	13,800
Capital Investment (\$ thousands)	\$63,450	\$121,000

16

17 **Q63. What are the BCA analysis results of the 2024 and 2025 PTMM workplan?**

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1 A63. When evaluating the subset of circuits included in the 2024 workplan, the benefit cost
2 ratio calculated was 3.6. And the benefit cost ratio calculated for the subset of circuits
3 selected for the 2025 workplan was 5.0. In both cases, the workplans include circuits
4 that have a higher benefit cost ratio for completing PTMM than the system average,
5 thus validating the Company's selection criteria of focusing on Tier 1 and Tier 2
6 circuits to maximize customer impacts while working towards implementing a full 10-
7 year pole and 5-year pole top equipment PTMM cycle in future years.

8

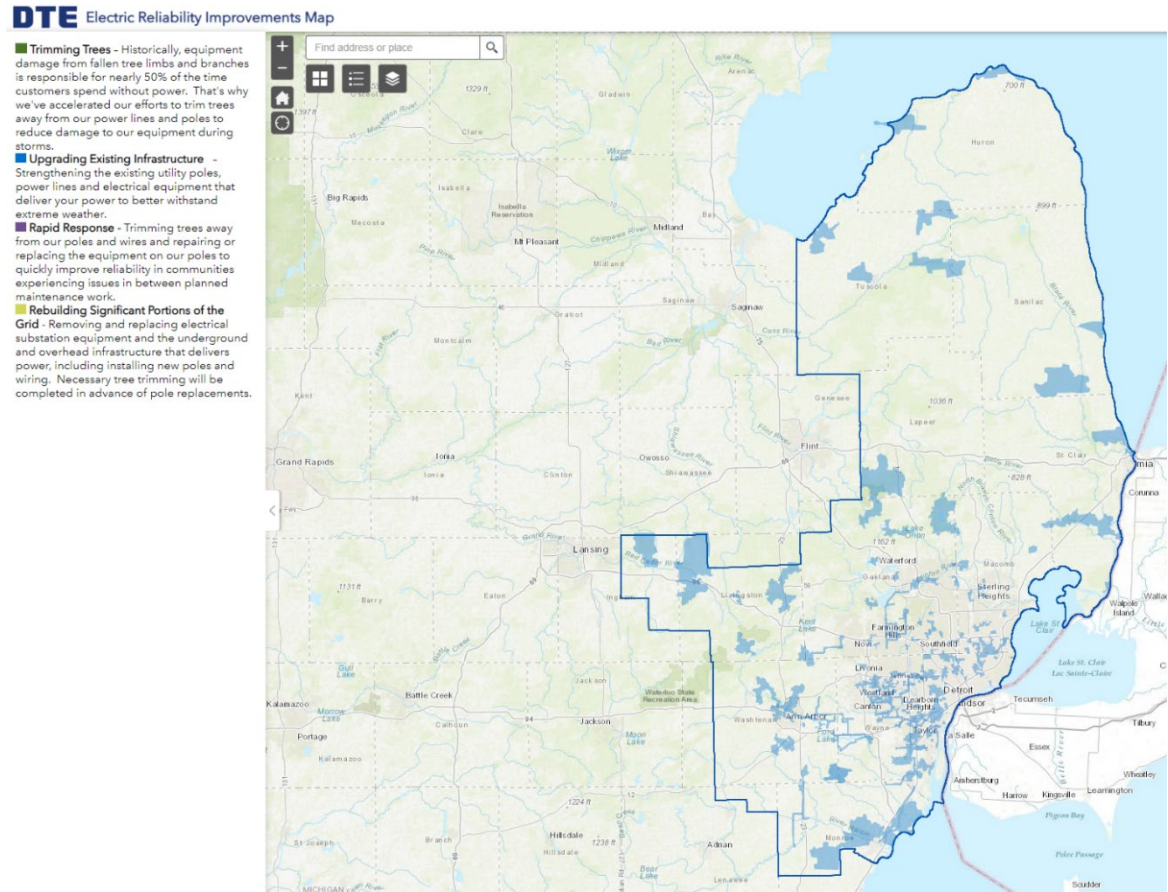
9 **Q64. How can customers stay informed about PTMM work being performed in their**
10 **area?**

11 A64. Customers interested in seeing if PTMM work is being performed in their respective
12 area can visit the Company's website at
13 [https://dte.maps.arcgis.com/apps/webappviewer/index.html?id=5d9dc2eb1244456189](https://dte.maps.arcgis.com/apps/webappviewer/index.html?id=5d9dc2eb124445618959ce788086e00e)
14 [59ce788086e00e](https://dte.maps.arcgis.com/apps/webappviewer/index.html?id=5d9dc2eb124445618959ce788086e00e). These maps are regularly updated to inform our customers of the
15 reliability work the Company is performing on their behalf, to visually display work
16 completed in the last 6 months, and work scheduled to be completed within the next 12
17 months. Please note that the PTMM and 4.8kV Hardening Programs are called
18 "Upgrading Existing Infrastructure" in the map provided on this website. This map also
19 shows Tree Trimming, Customer Excellence (called "Rapid Response") and Circuit
20 Conversion (called "Rebuilding Significant Portions of the Grid"). A current example
21 of this map showing only the "Upgrading Existing Infrastructure" layer can be seen in
22 Figure 15.

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Figure 15. Upgrading Existing Infrastructure Map



Substation Risk

Q65. What are Substation Risk projects?

A65. Projects in this category are designed to remediate failures of substations that have already occurred, or to prevent catastrophic substation failures in the future. Because a substation typically supports several circuits, substation catastrophic failure events often impact a large number of customers. The events typically are caused by significant equipment failure such as a transformer or switchgear, fires, or flooding events. In addition to affecting a large amount of customers, they can result in lengthy outages because an entire substation is difficult to restore, with methods often limited

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1 to Mobile Fleet Program assets such as diesel generators and portable substations, or
2 switching load to adjacent substations with available jumpering capacity. The amount
3 of adjacent substation jumpering that can be achieved, and how quickly it can be
4 implemented, is dependent on several factors such as same circuit voltage class,
5 adequate existing capacity and cable/conductor size, and sufficient operating devices
6 already installed in field. Substation Risk projects often target replacing at-risk
7 switchgear within the substations in order to reduce the risk of major outages.
8 Switchgear is an enclosure with breakers, relays, and wiring, and a breaker or cable
9 failure inside a switchgear can take out multiple circuits at once.

10
11 These Substation Risk projects are prioritized utilizing the Global Prioritization Model
12 (GPM) as discussed in more detail in Company Witness Kryscynski's testimony, at
13 substations where deployment of Mobile Fleet Program assets cannot restore the entire
14 substation load; in other words, customers will be out for more than 24 hours in the
15 event of a failure. Details of the projects included in this instant case can be found
16 below and in Exhibit A-23, Schedule M5.

17
18 **Q66. Please describe the drivers of the Substation Risk: McGraw project.**

19 A66. Record heavy rains in June 2021 led to significant, catastrophic flooding in the
20 McGraw substation. The sub-grade part of the substation was engulfed in storm water,
21 which caused the failure of position breakers, busses, transfer busses, and house service
22 panels. As a result, the substation experienced a total loss of load carrying ability that
23 caused 6,000 customer outages lasting between 16 hours to 5 days based on the ability
24 to restore power.

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Figure 16. Flooding Near McGraw Substation



2

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7

The Company's initial emergency response included a mix of jumpering load away from McGraw to adjacent substations, and use of the Mobile Fleet Program portable generation equipment. All customers were placed back on utility power within two weeks after the flooding event by means of station jumpering and breaker replacement,

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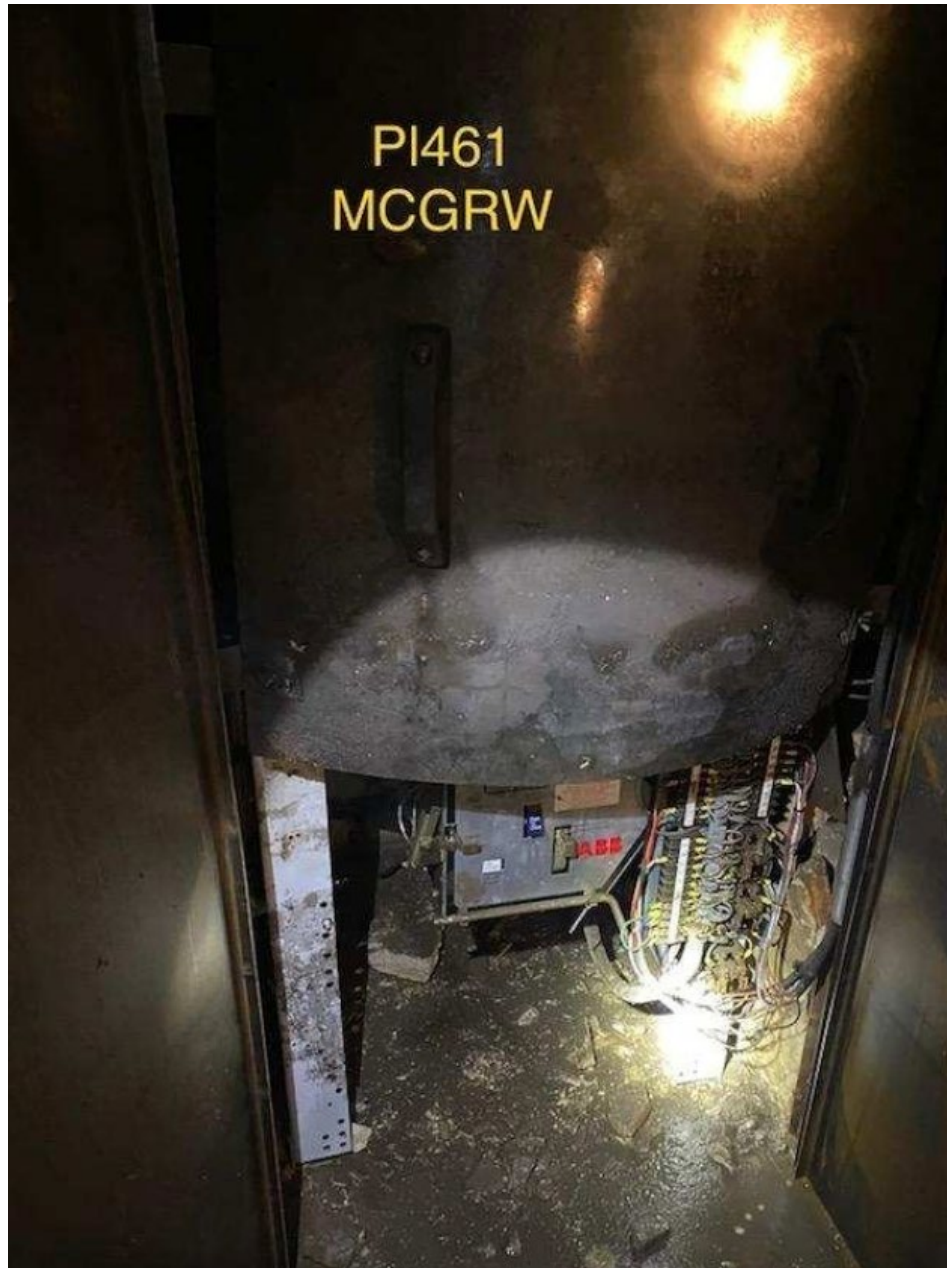
Figure 17. McGraw Substation Flooding – Example 1



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Figure 18. McGraw Substation Flooding – Example 2



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however, the substation has continued using some Mobile Fleet Program equipment and a temporary overhead circuit (pole farm) constructed on City of Detroit and MDOT property to bypass damaged and inoperable substation equipment, until a permanent solution is constructed on DTEE property. While the current temporary configuration

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1 supports load day-to-day, it is higher risk than standard utility construction, and there
2 have been subsequent outage impacts for these customers. For example, the portable
3 substation in the field was struck by a vehicle and taken out of service, which caused
4 additional outages to customers until a replacement could be installed. The temporary
5 configuration also poses a safety risk due to the lack of automatic ground detection
6 alarms to indicate a downed 4.8kV wire. Substation field personnel visit the substation
7 daily to manually check for grounds at McGraw until the permanent facilities can be
8 built. Additionally, customers have expressed concerns about the continued presence
9 of the large temporary mobile equipment located in residential neighborhoods.

10
11 After the initial emergency response, the Company's engineers and field personnel
12 assessed the substation's condition, as well as the long-term plans of the McGraw
13 substation and surrounding circuits. The Substation Risk: McGraw project was created
14 after these assessments with the goals of preventing future failures due to flooding and
15 returning customers to normal utility service.

16
17 **Q67. What is the scope of the Substation Risk: McGraw project?**

18 A67. The scope of the Substation Risk: McGraw project is to:

- 19 i) Install new substation equipment on the second level including a new circuit feeder,
20 transformer and ATO breakers, new relay and voltage control panels, and
21 network/SCADA capabilities are being installed to increase reliability.
22 Additionally, while all critical equipment has been moved out of the lower level,
23 sump pumps and a manual diversion valve have been installed to improve response
24 to any potential flooding in the basement.

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1 ii) Acquire land parcels and vacated right-of-way from the City of Detroit and MDOT
2 to allow exterior expansion for equipment to be removed from the basement.

3 iii) Construct exterior expansion of substation equipment including two 24-4.8kV
4 10/12 MVA transformers with circuit switcher protection and a 9-position PDC,
5 and network/SCADA capabilities installed to increase reliability.

6 iv) Decommission and remove failed substation equipment in the basement.

7

8 More details of this project can be found in Exhibit A-23, Schedule M5.

9

10 **Q68. What are the customer benefits of the Substation Risk: McGraw project?**

11 A68. This work will return customers fed from the McGraw substation to normal utility
12 service, removing the necessity for the continued use of the mobile generation
13 equipment, and the temporary pole farm, thus improving the reliability of service for
14 all affected customers. This project will also greatly reduce or eliminate future
15 flooding risk to the McGraw substation as all equipment necessary to serve customers
16 will be located on the second floor of the substation or outside of the building (rather
17 than the basement). The project is anticipated to be completed in 2024. Additionally,
18 the permanent utility infrastructure will allow for the removal of the large temporary
19 equipment that has been a customer concern.

20

21 **Q69. Should the Commission approve investment in Substation Risk: McGraw project**
22 **in this instant case?**

23 A69. Yes. This project is necessary to serve the customers fed by the McGraw substation in
24 a reasonable and prudent manner. This project will return McGraw back to full
25 operability, remove all mobile generation equipment, eliminating the need for the

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1 temporary pole yard, build switching and redundancy for these circuits, and restore
2 service to the customers with long-term utility equipment rather than the current
3 temporary solution.

4
5 **Figure 19. McGraw Substation – Temporary Pole Farm**



6
7 **Q70. Why was the Substation Risk: Flood Defense Program created?**

8 A70. The Substation Risk: Flood Defense Program was created as a response to heavy
9 rainfalls and flooding events that have been experienced in recent years at the
10 Company's substations.

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1 Class C and D substations⁹ were constructed in the 1930s and 1940s and were designed
2 to contain critical distribution assets underground in their basements. These older
3 substation designs rely on water-cooled equipment that requires a sewer connection,
4 making them vulnerable to catastrophic failures due to abnormally heavy rains that can
5 cause rapid flooding events.

6

7 The Company performed a detailed updated flooding risk analysis after the 2021
8 flooding events, and determined that five substations (Walker, Orchard, Madison,
9 Frisbee, and Scotten) serving approximately 17,000 customers were at elevated risk
10 and required flood mitigation measures.

11

12 **Q71. What is the scope of the Substation Risk: Flood Defense Program?**

13 A71. The scope of the Substation Risk: Flood Defense Program is to limit or prevent water
14 intrusion in vulnerable substations by performing the following work at five Class C/D
15 substations:

16

- 17 • Install one-way backflow prevention valves on existing sewer connected
- 18 dewatering systems;
- 19 • Install emergency dewatering pumps to discharge at ground level during sewer
- 20 backup events; and
- 21 • Seal conduit to help prevent water penetration into the substation.

22

⁹ A Class C substation is a general-purpose substation with three or more radially-fed 24 to 4.8kV transformers, a 4.8kV transformer bus, a 4.8kV transfer bus, and a 4.8kV linkage bus, operated together to provide a parallel-operated service with a maximum degree of continuity. A class D substation is designed to include the installation of one or more 120 to 40/24kV transformers and several 40/24kV circuits. Class D substations are usually designed for two or more 120kV buses, 120 to 40/24 kV transformers, and 40/24kV buses. The design may also include 345 and 230kV buses and switching and associated transformation to 120kV.

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1 This work will significantly reduce the risk of catastrophic failure at five substations to
2 ensure that the 17,000 associated customers have a more reliable, resilient grid. The
3 program is anticipated to be completed in 2024.

4
5 More details of this program can be found in Exhibit A-23, Schedule M5.

6

7 **Q72. What are the customer benefits of the Substation Risk: Flood Defense Program?**

8 A72. The Substation Risk: Flood Defense Program investments will reduce the risk of
9 catastrophic failure of five at-risk substations, thus reducing the risk of extended
10 outages for approximately 17,000 customers.

11

12 **Q73. Should the Commission approve investment in Substation Risk: Flood Defense**
13 **program in this instant case?**

14 A73. Yes, in my opinion the MPSC should approve the Flood Defense program for cost
15 recovery in the instant case because these investments are reasonable and prudent. As
16 discussed in this section of my testimony, this project is necessary to respond to the
17 substation flood analysis performed by installing back-flow prevention valves,
18 emergency water pumps, and sealing conduit to reduce the risk of flooding causing
19 catastrophic failure at the five identified substations which serve approximately 17,000
20 customers.

21

22 **Q74. Why was the Substation Risk: Apache project created?**

23 A74. A breaker position inside switchgear failed at the Apache Substation in 2015 which
24 resulted in a significant area-wide outage affecting nearly 11,000 customers with 81%
25 of affected customers being restored within 16 hours. The downtown business district

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1 of Troy, as well as surrounding commercial and residential areas were without
2 electrical service for a prolonged period of time.

3

4 An assessment was performed after emergency repairs were made, which identified the
5 remaining switchgear breakers were at-risk of a similar failure. A second catastrophic
6 failure could result in the loss of all switchgear positions, and up to 16 MVA of stranded
7 load. Stranded load occurs when customers cannot be restored by
8 jumpering/transferring customers to an adjacent circuit or substation leading to
9 prolonged customer outages across the entire substation area. In the example of
10 Apache, while some load can be transferred to adjacent circuits, up to 16 MVA cannot
11 be. The Substation Risk: Apache project was initiated to invest in appropriate
12 replacements to prevent this potential second catastrophic failure.

13

14 **Q75. What is the scope of the Substation Risk: Apache project?**

15 A75. The scope of the Substation Risk: Apache project is to:

- 16 • Replace (1) at-risk 19-position switchgear with (2) new 12-position switchgear
- 17 • Replace (3) circuit switchers with S&C 2020 circuit switchers
- 18 • Build system cable termination on new switchgear for all 13 circuits
- 19 • Decommission the existing at-risk 19 position switchgear once load is cut over
20 to new switchgear
- 21 • Install 12-5" conduit supporting substation exits
- 22 • Build (1) two-way manhole
- 23 • Build (9) three-way manholes
- 24 • Remove ~8,584 feet of old EPR and XLPE cable
- 25 • Install ~9,333 feet of new EPR cable

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- 1 • Replace (19) disconnect switches with pole-top switches at the station cable
- 2 poles
- 3

4 **Q76. What are the customer benefits of the Substation Risk: Apache Project?**

5 A76. The new switchgear will reduce the risk of catastrophic substation failures and
6 extended duration area-wide customer outages. The replacement of one at-risk 19-
7 position switchgear with two new 12-position switchgear will also provide load relief
8 to Apache circuits that exceed day-to-day limits. The project is anticipated to be
9 completed in 2024.

10

11 **Q77. Should the Commission approve investment in the Substation Risk: Apache**
12 **project in this instant case?**

13 A77. Yes. This project is necessary to reduce the risk of another catastrophic switchgear
14 breaker failure at the Apache substation potentially resulting in an extended duration
15 outage for the nearly 11,000 customers served by the Apache substation.

16

17 **Q78. Why was the Substation Risk: Chestnut project created?**

18 A78. The Chestnut substation has a single 19-position switchgear that is a single point of
19 failure. A switchgear failure could result in the loss of all switchgear positions and a
20 potential stranded load of 35 MVA with limited jumpering options, which would affect
21 approximately 6,000 customers across three cities. This type of potential failure is
22 similar to the Apache substation failure described earlier in my testimony, which would
23 result in a long-duration outage for the affected customers. The switchgear itself was
24 evaluated to be at high risk of failure based on a combination of years in service (53
25 years) and an equipment type that has experienced issues (GE air breaker). The

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1 Chestnut project was initiated to mitigate the combination of high equipment risk and
2 up to 15 MVA of stranded customer load by replacing the single at-risk 19-position
3 switchgear with two new 12-position switchgear.

4

5 **Q79. What is the scope of the Substation Risk: Chestnut project?**

6 A79. The scope of the Substation Risk: Chestnut project is to:

- 7 • Replace (1) at-risk 19-position switchgear with (2) 12-position switchgear
- 8 • Replaced and relocate (3) capacitor banks
- 9 • Install ~500 feet of 15-5" concrete encased duct bank
- 10 • Install ~10,000 feet of EPR cable and associated branch and straight joints
- 11 • Install (17) OMNI-Rupters

12

13 More details of this project can be found in Exhibit A-23, Schedule M5.

14

15 **Q80. What are the benefits of the Substation Risk: Chestnut project?**

16 A80. The new switchgear will reduce the risk of catastrophic substation failures and
17 extended duration area-wide customer outages, and will provide increased capacity to
18 serve 18 distribution circuits, while the old configuration was only capable of serving
19 12 distribution circuits. The project is anticipated to be completed in 2025.

20

21 **Q81. Was investment in the Substation Risk: Chestnut project requested in previous**
22 **rate cases?**

23 A81. Yes. The Substation Risk: Chestnut project was included in Exhibit A-12, Schedule
24 B5.4 and Exhibit A-23, Schedule M4 exhibits for Case Nos. U-21297, U-20836, U-

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1 20561, and U-20162. Substation Risk projects were not included in my direct testimony
2 in any prior rate cases before this instant case.

3

4 **Q82. Should the Commission approve investment in the Substation Risk: Chestnut**
5 **project in this instant case?**

6 A82. Yes. Per the responses provided above, this project is necessary to reduce the risk of a
7 catastrophic switchgear breaker failure at the Chestnut substation potentially resulting
8 in an extended duration outage for the 6,000 customers served by the Chestnut
9 substation.

10

11 **Q83. Why was the Substation Risk: Savage Stranded Load project created?**

12 A83. Following the fire at Apache substation, DTEE engineering teams assessed similar
13 switchgear across its service territory for risk potential. Savage substation was
14 identified as having a high-risk switchgear that did not have connections to adjacent
15 substations that would allow for jumpering of the load in the event of a failure of the
16 switchgear. This lack of jumpering capabilities created the risk of stranded load in the
17 event of failure which was determined to be approximately 30MVA of load.

18

19 **Q84. What is the scope of the Substation Risk: Savage Stranded Load project?**

20 A84. The scope of the Substation Risk: Savage project was to:

- 21 • Extend conduit and cable to feed (7) new primary switch cabinets
22 • Establish tie points to adjacent circuits and substations

23

24 More details of this project can be found in Exhibit A-23, Schedule M5.

25

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1 **Q85. What are the customer benefits of the Substation Risk: Savage Stranded Load**
2 **project?**

3 A85. Installing switch cabinets and establishing underground connections in the area
4 accomplish the primary goal of mitigating stranded load but also provided future
5 benefits. The new switch cabinets offer spare positions for future load growth as well
6 as operating flexibility between Savage, Lochdale, and Apache circuits in the event of
7 failures on these circuits. The project was completed in 2023.

8

9 **Q86. Should the Commission approve investment in the Substation Risk: Savage**
10 **Stranded Load project in this instant case?**

11 A86. Yes. This project was necessary to reduce the risk of a catastrophic switchgear breaker
12 failure at the Savage substation potentially resulting in an extended duration outage for
13 the 3,000 customers served by the Savage substation.

14

15 **Q87. Why was the Substation Risk: Belleville Switchgear Decommission project**
16 **created?**

17 A87. In the beginning of 2020, DTE's Engineering team identified the 4.8kV Belleville
18 switchgear as at end of life. Breakers inside the switchgear required multiple repairs
19 over the course of 5 years and there are no breakers replacements if they were to fail.
20 Control wiring inside the cubicle also required re-wiring which involved extended
21 planned shutdowns. The Belleville substation did experience a switchgear failure in
22 2022 which led to the condemnation of Bus 11 and limited operability. The Company's
23 equipment engineers determined that the switchgear at Belleville substation is at-risk
24 of further failures and needs to be fully decommissioned.

25

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1 **Q88. What is the scope of the Substation Risk: Belleville Switchgear Decommission**
2 **project?**

3 A88. The scope of the Substation Risk: Belleville Switchgear Decommission project is to:

- 4 • Bypass Belleville's 4.8kV switchgear by installing an overhead NOVA triple-
5 single reclosers just outside of the substation
- 6 • Convert the 4.8kV portion of Belleville substation from a Class A to a Class T
7 substation
- 8 • Reconfigure the (3) load-carrying circuits and throw-over circuit into (2) load-
9 carrying circuits

10

11 This project is expected to be completed in 2024. More details of this project can be
12 found in Exhibit A-23, Schedule M5.

13

14 **Q89. What are the benefits of the Substation Risk: Belleville Switchgear Decommission**
15 **project?**

16 A89. Decommissioning and removing the partially failed, at-risk 4.8kV switchgear at
17 Belleville substation and then reconfiguring the distribution circuits has enabled
18 continued service for approximately 1,300 customers. This work has reduced the risk
19 of extended outages for these customers if the switchgear were to experience another
20 failure in the future.

21

22 A future 4.8kV Conversion project at Belleville substation is discussed in Witness
23 Deol's testimony which will convert these circuits to 13.2kV and remove any
24 remaining 4.8kV equipment at Belleville substation.

25

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1 **Q90. Should the Commission approve investment in the Substation Risk: Belleville**
2 **Switchgear project in this instant case?**

3 A90. Yes. This project is necessary to reduce the risk of a catastrophic switchgear breaker
4 failure at the Belleville substation potentially resulting in an extended duration outage
5 for the 1,300 customers served by the 4.8kV Belleville substation.

6

7 **Q91. Why was the Substation Risk: Voyager project created?**

8 A91. Voyager is an industrial substation serving Stellantis. Stellantis has experienced
9 several interruptions due to the at-risk high side motor disconnects at Voyager
10 substation.

11

12 **Q92. What is the scope of the Substation Risk: Voyager project?**

13 A92. The scope of the Substation Risk: Voyager project was to:

- 14 • Install (4) piers for future circuit switcher installation
15 • Install anchor bolts for future circuit switcher installation
16 • Above grade work to replace the motor disconnects with new circuit switchers
17 will be scheduled at a later time with the customer

18

19 More details of this project can be found in Exhibit A-23, Schedule M5.

20

21 **Q93. What are the benefits of the Substation Risk: Voyager project?**

22 A93. The below grade work was completed during a planned customer shutdown to avoid
23 unnecessary customer outages. This below grade work will enable quicker replacement
24 of the at-risk equipment during a future project to replace this equipment and improve
25 reliability and operability at Voyager substation. This project was completed in 2023.

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1

2 **Q94. Should the Commission approve investment in the Substation Risk: Voyager**
3 **project in this instant case?**

4 A94. Yes. This project was necessary to complete below grade work during a planned
5 customer shutdown and this below grade work enables a future project to replace the
6 at-risk equipment.

7

8 **Q95. Why was the Substation Risk: Drexel project created?**

9 A95. Position I at Drexel substation experienced a failure in July 2016 which resulted in a
10 fire and damaged several positions in the Drexel switchgear. Approximately 7,500
11 customers are normally served by Drexel substation and over 3,000 customers were
12 transferred to adjacent substations to restore service. Replacing the switchgear and
13 restoring customers to their normal point of service will restore operability and reduce
14 loading constraints in the area.

15

16 **Q96. What is the scope of the Substation Risk: Drexel project?**

17 A96. The scope of the Substation Risk: Drexel project is to:

- 18 • Install (1) 9-position switchgear
- 19 • Install (1) 15/20/25 MVA transformer to feed new switchgear
- 20 • Install 6,900 feet of EPR system cable from new switchgear lineup to existing
- 21 cable poles
- 22 • Decommission and remove the damaged existing switchgear lineup
- 23 • Restore circuits to pre-fire configurations

24

25 More details of this project can be found in Exhibit A-23, Schedule M5.

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1

2 **Q97. What are the benefits of the Substation Risk: Drexel project?**

3 A97. Completing the Drexel switchgear replacement project will restore the area to its
4 normal configuration which reduces load on adjacent circuits and substations that have
5 been temporarily serving Drexel customers since 2016. Decommissioning and
6 removing the partially failed switchgear mitigates the risk of additional failures and
7 extended outages for the area. This project will be completed in 2024.

8

9 **Q98. Should the Commission approve investment in the Substation Risk: Drexel**
10 **project in this instant case?**

11 A98. Yes. Per the responses provided above, this project is necessary to mitigate the risk of
12 additional failures and extended outages for customers in this area.

13

14 **Q99. Why was the Substation Risk: Savage Switchgear Replacement project created?**

15 A99. The Savage substation has a single 16-position switchgear that is a single point of
16 failure. A switchgear failure could result in the loss of all switchgear positions and a
17 potential stranded load of 30 MVA with limited jumpering options, which would affect
18 approximately 3,000 customers throughout Troy. This type of failure would result in a
19 long-duration outage for the affected customers. The switchgear has been determined
20 to be at-risk of failure based on a review by the Company's equipment engineers. The
21 combination of high equipment risk and high stranded customer load was why the
22 Savage project was initiated. By splitting the existing single 16-position switchgear
23 into two new separate 9-position switchgears, the equipment risk is reduced and the
24 amount of stranded load (15 MVA) due to a single point failure.

25

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Q100. What is the scope of the Substation Risk: Savage Switchgear Replacement project?

A100. The scope of the Substation Risk: Savage Switchgear Replacement project is to:

- Remove existing parking area north of existing substation fence – approximately 7,800 sq. ft.
- Extend substation fence approximately 300 feet
- Perform site preparation and below grade for expanded substation yard
- Install concrete pads for new switchgear and three (3) 6 MVAR bus capacitor banks
- Install two (2) 9-position 2-high switchgear
- Install conduit and system cable to existing circuit cables feeding Savage circuits and neighboring circuits to enable jumper contingency
- Extend overhead 770 feet to establish two (2) portable ready locations
- Install two (2) sets of 3-333KVA regulators
- Decommission and remove existing 1960's vintage continuous line-up of one (1) 16-position switchgear at Savage substation

This project will be completed in 2024. More details of this project can be found in Exhibit A-23, Schedule M5.

Q101. What are the benefits of the Substation Risk: Savage Switchgear Replacement project?

A101. The new switchgear will reduce the risk of catastrophic substation failures and extended duration area-wide customer outages. It will also provide increased capacity

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1 to serve 12 distribution circuits while the old configuration was only capable of serving
2 10 distribution circuits. The project is anticipated to be completed in 2027.

3

4 **Q102. Was investment in the Substation Risk: Savage Switchgear Replacement project**
5 **requested in previous rate cases?**

6 A102. No. The Substation Risk: Savage Switchgear Replacement project is new and was not
7 included in any prior rate cases.

8

9 **Q103. Should the Commission approve investment in the Substation Risk: Savage**
10 **Switchgear Replacement project in this instant case?**

11 A103. Yes. Per the responses provided above, this project is necessary to mitigate the risk of
12 a switchgear failure at Savage substation which would result in a potential 30 MVA of
13 stranded load affecting 3,000 customers throughout Troy.

14

15 **Q104. Why was the Substation Risk: Seville project created?**

16 A104. Position B at Seville experienced a failure in 2023 and after a review by the Company's
17 engineers was determined unrepairable. Approximately 1,500 customers have been
18 temporarily transferred to adjacent circuits to continue service. No spare positions
19 currently exist at Seville substation to restore the area to normal configuration;
20 therefore, switchgear replacement is necessary.

21

22 **Q105. What is the scope of the Substation Risk: Seville project?**

23 A105. The scope of the Substation Risk: Seville project is to:

- 24
 - Replace one (1) failed 7-position switchgear with one (1) 9-position switchgear
 - Install new transformer secondary cables
- 25

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- 1 • Perform load transfers to re-establish Seville circuits to normal configuration

2

3 More details of this project can be found in Exhibit A-23, Schedule M5.

4

5 **Q106. What are the benefits of the Substation Risk: Seville project?**

6 A106. Restoring the area to normal configuration will allow the Company to return all circuits
7 to normal operating condition and restore system redundancy in the event of future
8 outage events. Additionally, the new standard 9-position switchgear will provide two
9 spare circuit positions for future use to support customer growth as necessary.

10

11 **Q107. Should the Commission approve investment in the Substation Risk: Seville project**
12 **in this instant case?**

13 A107. Yes. Per the responses provided above, this project is necessary to restore the Seville
14 substation to a normal operating condition and return all circuits to loads that are within
15 an acceptable range.

16

17 **Q108. Why was the Substation Risk: Imlay project created?**

18 A108. The Substation Risk: Imlay project is driven by safety concerns including:

- 19 • Substation equipment is within arm's reach when walking through the substation
20 posing a safety hazard;
- 21 • Imlay substation has poor lighting conditions;
- 22 • Imlay substation has a transformer that operates vertically by lifting which poses a
23 safety risk as it could result in a flashover during operation;
- 24 • Imlay substation is not built to DTEE standards;

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- 1 • Imlay substation lacks necessary space to rebuild equipment on the existing
- 2 120x140ft site;
- 3 • Imlay substation is built on differing elevations which make retrofits or upgrades
- 4 difficult;
- 5 • Imlay substation has a high 5-year average SAIDI of 549 minutes.

6

7 **Q109. What is the scope of the Substation Risk: Imlay project?**

8 A109. The scope of the Imlay Substation Risk project is:

- 9 • Replace OTSGO substation equipment to increase capacity and establish (2) new
- 10 distribution circuits.
- 11 • Rebuild 30 miles of overhead conductor
- 12 • Convert 30 miles of 4.8kV to 13.2kV
- 13 • Transfer ~4.9MVA of load from IMLAY substation to OTSGO substation
- 14 • Decommission (1) 40-4.8kV substation (IMLAY).
- 15 • Pre-convert and convert about 30 miles (includes part of IMLAY and OTSGO).
- 16 • Transfer ~4.9MVA of load from Imlay Substation to OTSGO Sub

17

18 More details of this project can be found in Exhibit A-23, Schedule M5.

19

20 **Q110. What are the benefits of the Substation Risk: Imlay project?**

21 A110. This project will eliminate the substation electrical hazards at Imlay substation and

22 improve the reliability for customers by rebuilding portions of the overhead circuits.

23

24 **Q111. Should the Commission approve investment in the Substation Risk: Imlay project**

25 **in this instant case?**

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1 A111. Yes. Per the responses provided above, this project is necessary to mitigate the safety
2 risks posed by its current configuration.
3

4 **Frequent Outage Programs (CEMI)**

5 **Q112. What programs are included in Frequent Outage Programs?**

6 A112. In addition to strategic programs and projects to support grid reliability, the Company
7 has shorter term programs to address pockets of the grid where customers have
8 experienced multiple outages. There are two primary programs under Frequent Outage
9 Programs: the Customer Excellence (CE) Program and the Strategic Reliability
10 Improvement Program (SRIP).
11

12 The CE program was established to provide rapid solutions to small pockets of
13 customers experiencing poor reliability. These customers are identified as experiencing
14 four sustained outages (SAIFI > 4.0), or nine momentary outages (MAIFI > 9.0) per
15 year. The prioritization method for the CE program relies on Advanced Metering
16 Infrastructure (AMI) data to identify these customers on a rolling 12-month basis to
17 address issues more rapidly than other programs which rely on the annual analysis of
18 reliability events. In addition to reliability event data, the prioritization also includes an
19 evaluation of the time since the area's last tree trim was completed, any other planned
20 work on the circuits, as well as customer complaints.
21

22 Upon identification of a circuit that meets the CE prioritization criteria and is selected
23 for construction, the Company conducts a field patrol to assess both equipment and tree
24 conditions impacting reliability. After the patrol, the scope of work is developed for
25 the identified equipment and tree-related problems. In addition to the damaged or failed

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1 equipment replacements and tree trimming, the scope of work also includes checking
2 operating equipment to ensure it is functioning properly, conducting fault studies to
3 ensure fuses are properly sized, and installing additional equipment, such as reclosing
4 devices and animal guards, to prevent future outages. On average, the solutions require
5 investments between \$60,000 and \$80,000 per circuit to implement.

6

7 The SRIP Program performs improvements to either portions of a circuit (customer
8 pockets), or entire circuits as appropriate. The primary distinctions between the CE and
9 the SRIP Programs are that circuits are normally selected for the SRIP Program based
10 on both a 12-month and a three-year average circuit SAIDI and SAIFI performance,
11 MPSC complaints, and regional expertise on customer needs. In addition, the scope of
12 work performed under the SRIP Program is more comprehensive, and typically
13 requires investments between \$250,000 and \$300,000 per circuit to implement.

14

15 **Q113. What is the Company's Pre-Summer Storm Strengthening (PS3) process?**

16 A113. Beginning in 2021 after a summer with a high number of storms and associated
17 customer outages, the Company began an annual process of analyzing the performance
18 data of all circuits following each summer storm season. This analysis identifies circuits
19 expected to have the worst reliability performance. The PS3 process allocates circuits
20 to multiple programs such as Tree Trim, PTMM, CE, SRIP, and 4.8kV Hardening to
21 ensure they receive improvements before the subsequent summer storm season.

22

23 **Q114. Has the Company continued the Pre-Summer Storm Strengthening process of**
24 **identifying circuits that are at higher risk during storms and performing**
25 **investments on them?**

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1 A114. Yes. The Company has continued this process. For 2023, work was performed on 255
2 circuits within the Frequent Outage (CEMI) Programs and the program plans to
3 perform work on 166 circuits in 2024 and 215 circuits in 2025 (Table 13).
4

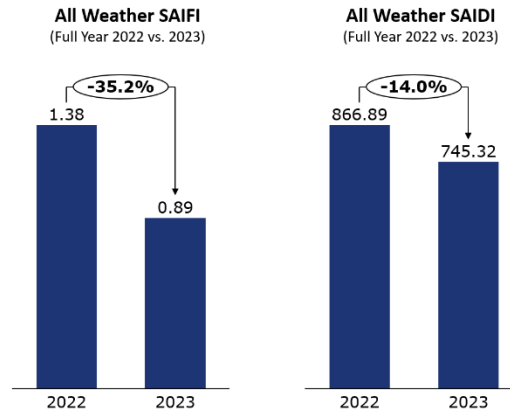
5 **Table 13. Frequent Outage Programs (CEMI) 2023-2025**

	2023 Forecast	2024 Forecast	2025 Forecast
CE Circuits	183	100	130
SRIP Circuits	72	66	85
Total Frequent Outage (CEMI) Program Circuits	255	166	215
Capital Investment (\$ thousands)	\$63,963	\$48,050	\$62,504

6

7 **Q115. How do Frequent Outage Programs (CEMI) benefit customers?**

8 A115. Frequent Outage Programs (CEMI) perform circuit improvements that increase electric
9 service reliability for customers who have experienced recent poor reliability. The
10 Company measures the reliability of the circuits selected for the Frequent Outage
11 (CEMI) Program before and after the work is completed (Figures 20 and 21).
12

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2**Figure 20. Frequent Outage Programs (CEMI) All Weather**

3

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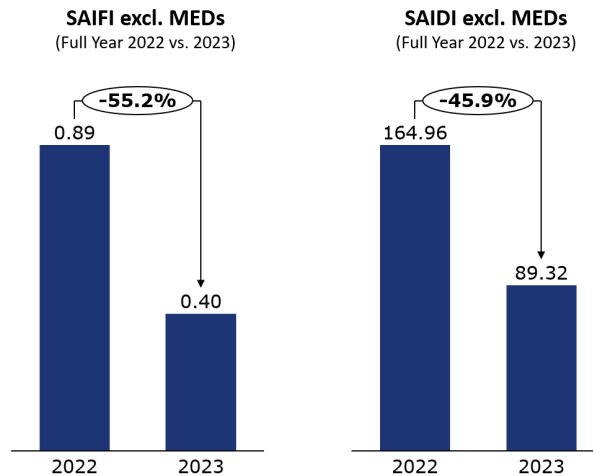
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Although weather is variable year to year and can impact comparisons of circuit performance, Figure 20 shows that customers on circuits where Frequent Outage (CEMI) work was performed experienced a 35.2% improvement in All Weather SAIFI and a 14.0% improvement in All Weather SAIDI when comparing 2023 to 2022.

Figure 21. Frequent Outage Programs (CEMI) Excl. MEDs

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12

When excluding the weather impacts of major event days, Figure 21 shows that customers on circuits where Frequent Outage (CEMI) work was performed experienced even greater reliability improvements, a 55.2% improvement in SAIFI

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1 excluding MEDs and a 45.9% improvement in SAIDI excluding MEDs when
2 comparing 2023 to 2022.

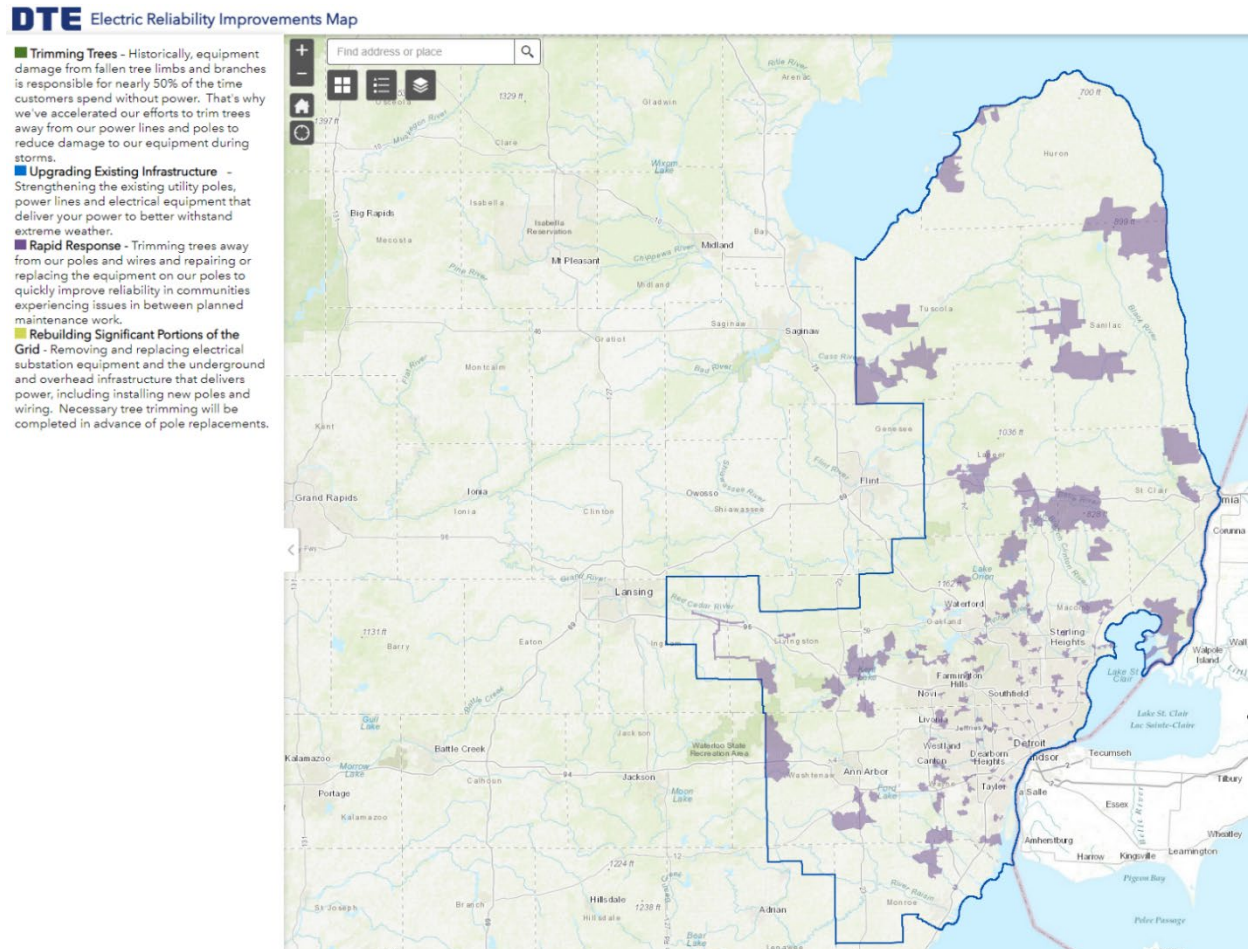
3

4 **Q116. How can customers stay informed about Customer Excellence work being**
5 **performed in their area?**

6 A116. Customers interested in seeing if Customer Excellence work is being performed in their
7 respective area can visit the Company's external website at
8 [https://dte.maps.arcgis.com/apps/webappviewer/index.html?id=5d9dc2eb1244456189](https://dte.maps.arcgis.com/apps/webappviewer/index.html?id=5d9dc2eb124445618959ce788086e00e)
9 [59ce788086e00e](https://dte.maps.arcgis.com/apps/webappviewer/index.html?id=5d9dc2eb124445618959ce788086e00e). These maps are regularly updated to inform our customers of the
10 reliability work the Company is performing on their behalf, to visually display work
11 completed in the last 6 months, and work scheduled to be completed within the next 12
12 months. Please note that the Frequent Outage (CEMI) Program is called "Rapid
13 Response" in the map provided on this website. This map also shows Tree Trimming,
14 4.8kV Hardening and PTMM (called "Upgrading Existing Infrastructure"), and Circuit
15 Conversion (called "Rebuilding Significant Portions of the Grid") A current example
16 of this map showing only the Rapid Response layer can be seen in Figure 22.
17

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Figure 22. Frequent Outage Programs (CEMI) Map



Cable Replacement Program

Q117. What is Underground (UG) System Cable, and how is it different from Underground Residential Distribution (URD) Cable?

A117. System cable is a specific type of cable designed and used for underground distribution and subtransmission on the Company's primary electric system. System Cable consists of large diameter cable surrounded by various types of insulation, and it is installed underground in vaults and ducts that run between manholes (Figure 23 and 24).

System cable is used for a different purpose than URD cable. System cable is used to transmit higher voltage electricity from substation to substation and to feed primary

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1 circuits, while URD cable is designed to provide lower voltage electricity directly to
2 residential neighborhoods. URD is discussed in more detail later in my direct
3 testimony.

4

5 **Q118. What are the key drivers of the Company's Cable Replacement program?**

6 A118. System cable is a critical component of the distribution and subtransmission system,
7 and while system cable provides high resiliency to storms, system cable failures do
8 happen, and can interrupt a large number of customers for an extended period of time
9 due the longer amount of time it typically takes to locate and replace a failed cable.
10 System cable replacement is an industry standard program to reduce system risk and
11 support reliability.

12

13 When a system cable fails, the customers fed from that circuit are typically jumpered
14 to a redundant, or back-up cable, to restore power, and remain on the alternate circuit
15 until the original cable is replaced and back in service. The process to replace the cable
16 includes locating the fault, de-energizing the circuit, cutting the failed section(s),
17 pulling the failed cable out of the conduit, installing new cable, reconnecting (splicing)
18 the new cable to the existing circuit, and re-energizing the circuit. During the time it
19 takes to find and repair the cable, the system has lost redundancy and has increased risk
20 for longer duration outages (if a failure occurs on the redundant circuit). System cable
21 failures can also cause failures in other equipment, including adjacent cables and
22 switchgear, which can then impact an even larger number of customers for a longer
23 period of time. The Company has had an average of 234 system cable failures per year
24 over the last six years (Table 14).

25

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No.1 **Table 14. System Cable Failures by Cable Type and Year**

Failures by Cable Type	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual
PILC	200	193	161	180	202	171
EPR	20	24	24	17	24	37
VCL	11	4	6	5	8	16
Gas	11	9	5	3	3	12
XLPE Post-1990	1	-	-	-	-	-
XLPE Pre-1990	9	3	7	5	1	16
Butyl Rubber	3	2	-	3	2	3
Total Cable Failures	255	235	203	213	240	255

2 **PILC:** system cable that is insulated with paper and lead3 **EPR:** system cable that is insulated with ethylene propylene rubber4 **VCL:** system cable insulated with varnished cambric5 **Gas:** system cable that is insulated with nitrogen gas under pressure6 **XLPE:** system cable that is insulated with cross-linked polyethylene7 **Butyl Rubber:** system cable that is insulated with butyl rubber

8

9 During system cable emergent restoration, the crews may experience multiple
10 challenges, which can complicate the work or slow progress on remediation of the
11 failure. In some instances, field crews find underground ducts have collapsed on the
12 cables, making the cable extremely difficult, or in some cases impossible to replace
13 without repairing the ducts (Figure 23). Safety concerns during restoration sometimes
14 cause other intact cables near the failed cable to require a shutdown, meaning they must

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1 be de-energized from the substation to make the site safe for work. Other examples of
2 safety concerns include pumping water out of the manholes and managing the
3 wastewater, ensuring the air quality is safe for entry, and often including remediation
4 of contaminants. Once the manholes can be entered safely, the work includes inspecting
5 and testing long stretches of cable to find the fault, and identification of adjacent
6 hazards. Finally, the crews typically pull (Figure 25) and splice the cable as described
7 above, which can be difficult during an emergent failure and restoration situation.

8
9 **Figure 23. System Cable – UG Collapsed Duct**



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Figure 24. System Cable – Cable Inside Manhole



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Figure 25. System Cable Pulling (Removal)



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In addition to aging issues, different types of cables are known to have specific failure modes. As an example, XLPE (cross-linked polyethylene) system cable manufactured before 1990 has a design defect that leads to premature insulation breakdown and failures (also called “treeing”) and has contributed to switchgear failures. For another example, gas cable which is designed to have cavities within the insulating layer that are filled with nitrogen gas under pressure is an obsolete design, prone to mechanical

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1 damage that leads to leaks and failures, as well as costly repairs. As detailed in the
2 DGP, Exhibit A-23, Schedule M8 (as supported by Company Witness Kryscynski),
3 section 4.3.6 on page 46, approximately 63% of the Company's system cable is beyond
4 useful life expectancy. Useful life is a standard industry term that does not represent
5 the actual life of an asset, but rather the age at which an installed asset is expected to
6 require increasing maintenance and reduced performance such that it is often more
7 prudent to replace than to continue to repair and maintain. While age is not the only
8 factor to determine a need for replacement, based on the Company's experience, failure
9 rates increase with age as older cable is typically exposed to more fault currents and
10 has longer water exposure.

11

12 Table 15 shows the average age of the different types of the approximately 3,100 miles
13 of system cable that are within the scope of the Cable Replacement Program. The
14 typical useful life expectancy of system cable is 35 to 40 years, although actual useful
15 life varies depending on cable type and field conditions. Based on its asset health
16 assessment for system cable, the Company has determined that approximately 28% of
17 its system cable is at-risk cable and a candidate for replacement, including XLPE cable
18 manufactured before 1990, gas cable, VCL (varnished cambric lead), and paper-
19 insulated-lead cable (PILC) cable greater than 60 years in age. The Company replaces
20 system cable because of the high number of customers who experience an outage when
21 system cable fails without available redundancy and the time it takes to locate and
22 replace the failed system cable.

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Table 15. Cable Types - Average Age and Life Expectancy

Cable Type	PILC	EPR	VCL	Gas	XLPE Pre-1990	XLPE Post- 1990	Butyl
Miles	2,069	748	95	47	58	48	31
% of Total Population	66.8%	24.2%	3.1%	1.5%	1.9%	1.5%	1.0%
Average Age	55	18	64	59	40	23	57
Useful Life Expectancy	40	35	40	40	25	40	25

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Q119. What is the scope of the Cable Replacement Program?

9

A119. The Cable Replacement program exists to identify and replace at-risk system cable.

10

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Q120. Was the Cable Replacement Program in the prior rate cases?

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1 A120. Yes, the Cable Replacement Program was included in Case Nos. U-21297, U-20836,
2 U-20561, and U-20162.

3

4 **Q121. Did the Commission support investments for the System Cable Replacement**
5 **program in prior rate cases?**

6 A121. Yes. The Commission stated in its Order for Case No. U-21297,

7 “The Commission finds that the company’s requested funding should be
8 approved for inclusion in rate base with the Staff’s proposed 10% reduction to
9 protect against over-projections. The Commission recognizes that regular
10 maintenance is necessary and that faulty cables should be replaced, and DTE
11 Electric provided evidence that multiple factors are considered in determining
12 where replacements are necessary including vintage, number of failures, and
13 number of affected customers, as well as safety improvements. 3 Tr 531-542,
14 581-582. ... Finally, the Commission disagrees with the ALJ and does not find
15 that it is necessary to separate expenditures by project for this program.”

16

17 **Q122. What is the Company’s policy for system cable replacement and how are circuits**
18 **selected?**

19 A122. The Company’s equipment engineers review all system cable on DTEE’s underground
20 system and prioritize cable for replacement based on insulation type, quantity of
21 failures, circuit loading, and age of cable. From these factors, a composite score is
22 calculated and the circuits with the highest risk are replaced.

23

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1 **Q123. What sections of cable are replaced by the Cable Replacement Program?**

2 A123. The Cable Replacement Program replaces all sections of cable that are deemed at-risk
3 based on their composite score as discussed above. If there are sections of cable on a
4 circuit that are not deemed to be at-risk, they are not replaced by the program.

5

6 **Q124. How much system cable was replaced in 2023 and prior years?**

7 A124. The Company replaced 8 miles of system cable in 2023 and has replaced 41.4 miles of
8 system cable over the last six years (Table 16).

9

10 **Table 16. System Cable Program 2018-2025**

	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Forecast	2025 Forecast
Cable Miles Replaced	5	10	6	7.4	5	8	10.3	11.3
Capital Investment (\$ thousands)	\$9,213	\$10,945	\$12,139	\$14,984	\$27,746	\$22,832	\$15,001	\$16,501

11

12 **Q125. How much system cable replacement is planned for 2024-2025?**

13 A125. The Company plans to replace approximately 10 miles in 2024 and 11 miles in 2025
14 (Table 16).

15

16 **Q126. How does the Cable Replacement program benefit customers?**

17 A126. Replacing at-risk system cable supports continued reliability for customers. The
18 underground cable system is designed with multiple redundancies to ensure customer
19 reliability. While single cable failures do not normally result in customer outages, if
20 the primary and redundant cables fail at the same time, it results in prolonged outages
21 for customers. Some types of industrial class customers such as hospitals, aren't able

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1 to tolerate the risk of running with a single cable, and therefore reduce or shut down
2 some functions when this happens. This program reduces overall risk to customers and
3 the grid by proactively replacing cables before they fail, in order to ensure necessary
4 redundancies for this critical part of the system as designed.

5

6 **Underground Residential Distribution (URD) Replacement Program**

7 **Q127. What is Underground Residential Distribution (URD) Cable, and why does the**
8 **Company replace it?**

9 A127. URD is a specific type of cable designed for underground residential use on the
10 Company's secondary electric system. URD consists of small diameter cable
11 surrounded by polyethylene insulation and is either directly buried into the ground or
12 less frequently is installed inside conduit (Figure 26). Because underground repairs can
13 take significant amounts of time to locate and repair when compared to overhead
14 infrastructure, URD systems are typically looped so that there are two paths to feed
15 customers in case one URD cable fails.

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Figure 26. URD Cable – Example



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As mandated by Michigan Administrative Code R. 460,512, all residential subdivisions in the Company’s service territory built since January 1, 1971 are served with URD cable. There are two primary types of URD cable, differentiated by manufacture date. Pre-1985 URD cable has XLPE (non-tree retardant) insulation, while post-1985 the insulation has TR-XLPE (tree-retardant) insulation. In cable insulation, “treeing” refers to the tree-like pattern of insulation breakdown. The breakdown typically originates at an impurity or defect in the solid insulation and grows gradually over time to resemble the branches of a tree, ultimately leading to a cable failure. There are nearly 11,000

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1 total miles of URD cable on the system, with approximately 2,068 miles (24%) being
2 pre-1985 non-tree retardant vintage (Table 17).

3

4

Table 17. URD Cable Types - Average Age and Life Expectancy

URD Type	Pre-1985	1985+
URD Cable Miles	2,068	8,512
% of Total Population	24%	76%
Average Age (Years)	46	20
Life Expectancy (Years)	40	40

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In addition to failures caused by treeing described above, in general, the rate of URD cable failures increases with the age of the cable, and the rate further increases once a cable experiences its first failure. Manufacturer expected useful life for URD cable is approximately 40 years. Useful life is a standard industry term that does not represent the actual life of an asset, but rather the age at which an installed asset is expected to experience increasing failure rates and reduced performance such that it is often more prudent to replace than to continue to repair and maintain. For the six-year period from 2018 through 2023, there were on average approximately 930 URD cable failures per year as seen in Table 18.

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Table 18. URD Cable Failures

	2018	2019	2020	2021	2022	2023	2018-2023 Average
URD Cable Failures	1,039	755	1,036	986	900	864	930

2

3

Q128. What is the scope of the URD Replacement Program?

4

A128. There are two primary types of work performed by the URD Replacement Program:

5

prioritizing and replacing existing URD cable and replacing live-front UG transformers

6

(described below) with dead-front UG transformers.

7

8

The program prioritizes and replaces URD cable based on multiple factors including

9

number of failures on the circuit, and number of customers affected by those failures,

10

and URD cable type. The program also includes the replacement of live-front

11

transformers with dead-front transformers. Some URD cable is fed from live-front

12

transformers, which is an obsolete design that does not include protective coverings

13

over energized equipment, and therefore poses a potential safety risk to crews in the

14

field while performing operating work once the external transformer covering is

15

removed.

16

17

Single URD cable faults (outages) are typically restored quickly after an UG splicing

18

crew arrives and bypasses the URD failure by back feeding the customers from another

19

source on the URD loop. However, once the customers are restored, there is follow-up

20

work required to locate and repair the URD fault that caused the original outage, and

21

to restore the system to normal operating conditions. This follow-up work is called an

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1 open loop. These open loops leave the system without redundancy, such that if a second
2 URD failure occurs on the same URD loop, a new long-duration outage (4+ hours) will
3 result for the customers as there is no redundancy to back feed the customers as
4 described above, while replacing the failed URD cable. Second URD failures within
5 six months of the original failure have occurred on average 49 times annually over the
6 last six years (Table 19).

7 **Table 19. URD Double Cable Failures Within 6 months**

	2018	2019	2020	2021	2022	2023	2018-2023 Average
URD Double Cable Failures	32	18	37	59	32	115	49

8

9 In addition, planned replacements are more cost effective than repairing failures, as the
10 Company can strategically plan to replace entire circuits of URD and live-front
11 transformers, rather than reactively fixing smaller sections of the circuit following a
12 failure.

13 **Table 20. URD Double Cable Failure Outage Data**

URD Double Failures w/in 6 months	2018	2019	2020	2021	2022	2023
Customers Impacted	1,491	965	1,923	2,542	1,749	5,415
Outage Duration	137 hours	85 hours	182 hours	370 hours	187 hours	791 hours
Average Outage Duration	4.3 hours	4.7 hours	4.9 hours	6.3 hours	5.9 hours	6.9 hours
Total Customer Outage Minutes	356,604	265,151	484,347	837,078	683,363	2,574,899

14

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1 URD Replacement Program investments include design for the following year's
2 program, remediation of identified hazards to streamline execution of the following
3 year's plan, the replacement of the targeted URD miles, and the replacement of live-
4 front transformers with dead-front transformers (Figures 27 and 28).

5

6

Figure 27. Live-front UG Transformer



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Figure 28. Dead-front UG Transformer



Q129. Was the URD Replacement Program included in prior rate cases?

A129. Yes, the URD Replacement Program was included in Case Nos. U-20162, U-20561, U-20836, and U-21297.

Q130. Were URD Replacement Program investments supported in prior rate cases?

A130. Yes. The Commission stated in its Order for Case No. U-21297,

“The Commission finds that the company’s requested funding should be approved for inclusion in rate base with the Staff’s proposed 10% reduction to protect against over-projections. The Commission recognizes that regular maintenance is necessary and that faulty cables should be replaced, and DTE Electric provided evidence that multiple factors are considered in determining

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1 where replacements are necessary including vintage, number of failures, and
2 number of affected customers, as well as safety improvements. 3 Tr 531-542,
3 581-582. ... Finally, the Commission disagrees with the ALJ and does not find
4 that it is necessary to separate expenditures by project for this program.”
5

6 **Q131. How much URD cable was replaced in 2023?**

7 A131. The URD Replacement Program replaced 75.3 miles of URD cable in 2023 and has
8 replaced approximately 223 miles of URD cable from 2018-2023 (Table 21).
9

10 **Table 21. URD Cable Miles and Transformers Replaced 2018-2023**

	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual
URD Miles Replaced	71.6	3.6	3.6	24.5	44.7	75.3
Live-front Transformers Replaced	-	-	1	63	110	111
Capital Investment (\$ thousands)	\$10,915	\$362	\$964	\$4,705	\$7,043	\$13,750

11

12 **Q132. Why is the planned investment in Exhibit A-12, Schedule B5.4 for URD**
13 **Replacement shown as \$0 in 2024 and 2025?**

14 A132. Because the Commission approved the Company’s Infrastructure Recovery
15 Mechanism (IRM) in Case No. U-21297, and URD Replacement investments are
16 addressed through that mechanism, the investments for URD Replacement have been
17 moved from Exhibit A-12, Schedule B5.4 to the IRM Exhibit A-33 Schedule X1 for
18 2024 and 2025.
19

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1 **Q133. How does the URD Cable Replacement Program benefit customers?**

2 A133. The program will improve reliability by reducing the number of residential customer
3 interruptions experienced by URD cable failures in the areas in which this program has
4 completed work. This will also benefit customers by reducing the risk of multiple
5 failures and long duration outages due to pre-existing open loops as described above.

6

7 **Breaker Replacement Program**

8 **Q134. What are substation breakers and substation reclosers, and what purpose do they**
9 **serve?**

10 A134. The path electricity travels across the system can be subjected to interruptions due to a
11 variety of factors (e.g., a tree falling on an overhead electrical line), which can cause
12 outages and potentially dangerous situations for customers and employees. Electrical
13 switches, most commonly breakers or reclosers, are in place at points along the network
14 to recognize and isolate these interruptions (also known as electrical faults) from the
15 rest of the distribution system. These switches help to minimize equipment damage
16 from electrical faults and allow power to continue flowing to as many customers as
17 possible while restoration is completed for the damaged circuits.

18

19 At the subtransmission and distribution levels, there are large breakers (switches) at
20 stations and substations that interrupt the current flow when a fault is detected to
21 minimize equipment damage and to isolate the faulted equipment from the rest of the
22 system.

23

24 Downstream from the substation breakers, located on distribution circuits, are
25 substation reclosers. Substation reclosers perform similarly to a breaker. When they

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1 detect faults, they open and isolate the interruption to a smaller area, impacting fewer
2 customers. Substation reclosers can prevent the substation breaker from opening,
3 avoiding a larger circuit level outage. Additionally, these reclosers can be used to tie
4 two circuits together so that, in the event of an outage, one circuit can provide power
5 to the other. Reclosers have a key role to play in improving reliability and are the
6 foundation of the automation program.

7

8 **Q135. What is included in the Breaker Replacement Program?**

9 A135. The Company has approximately 6,000 breakers on the electrical distribution and
10 subtransmission systems with approximately 60% of those breakers at an age beyond
11 their life expectancy. The breakers included in the replacement program have an
12 obsolete design, typically utilizing insulation oil for fault extinguishing.

13

14 Breakers replaced by the Breaker Replacement Program are classified into four
15 categories: distribution breakers, subtransmission breakers, H-breakers, and substation
16 reclosers. In addition to replacing breakers, the program also replaces relays and
17 controls to make the equipment SCADA-ready. SCADA (supervisory control and data
18 acquisition) utilization on equipment, will provide the Electric System Operations
19 Center (ESOC) greater visibility to system performance, which will allow ESOC
20 personnel to remotely reconfigure the grid to restore customers by isolating faults
21 and/or transferring load to adjacent circuits during both planned and unplanned
22 outages.

23

24 **Q136. Was the Breaker Replacement Program in the prior rate cases?**

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1 A136. Yes, the Breaker Replacement Program was included in Case Nos. U-20162, U-20561,
2 U-20836, and U-21297.

3

4 **Q137. Were Breaker Replacement Program investments supported in prior rate cases?**

5 A137. Yes. The Commission stated in its Order for Case No. U-21297,

6 “The Commission finds that the replacement of obsolete circuit breakers is the
7 type of work, like the removal of arc wire, that is necessary and lends itself to
8 few alternatives. The Commission disagrees with the ALJ and approves DTE
9 Electric’s requested funding for inclusion in rate base but adopts the Staff’s
10 proposed 10% reduction to the company’s test year request as a check on the
11 potential for over-projections. The company provided evidence that 60% of
12 breakers in the distribution and subtransmission systems (including substation
13 reclosers) are beyond their life expectancy. DTE Electric provided the criteria
14 used for selecting which breakers to replace and indicated that it plans to replace
15 35 breakers in 2023 and 36 in 2024. 3 Tr 543-544. While the evidentiary
16 showing could have been more robust, the Commission believes that this is
17 important work that needs to be done and approves the requested funding with
18 the 10% reduction.”

19

20 **Q138. What are the customer benefits from the Breaker Replacement Program?**

21 A138. The benefits of breaker replacement and enhanced relaying and controls include
22 enhanced safety, reduction of substation outage risk caused by breaker failures,
23 improved customer reliability, reduction in reactive expenditures due to breaker
24 failures, added ability to utilize SCADA controls, and the reduction of outage duration
25 due to enhanced fault location and event analysis provided by SCADA capability.

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2

Table 22. Breaker Failures 2019-2023

Installation Decade	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	Total
Unknown	-	1	-	-	-	1
1930s	5	1	3	1	1	11
1940s	4	2	2	8	2	18
1950s	36	38	35	55	48	212
1960s	17	24	7	15	9	72
1970s	33	19	16	29	17	114
1980s	13	10	7	7	17	54
1990s	27	34	22	34	26	143
2000s	14	6	6	10	21	57
2010s	6	6	32	1	19	64
2020s	-	-	-	-	1	1
Total Breakers Failures	155	141	130	160	161	747

3

4 **Q139. How are breakers selected for replacement?**

5 A139. The candidates for breaker replacements are chosen by the Company's equipment
6 engineers who review all breakers on the system. Breakers are prioritized based on the
7 following criteria:

- 8 • Breakers with known performance issues;
- 9 • Breakers with no or limited availability of spare parts;
- 10 • Breakers with insulation oil for fault interrupting medium which is
- 11 flammable; and
- 12 • Breakers that require short inspection cycles compared to the rest of the
- 13 breakers on our system.

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1

2 **Q140. Can you provide a specific example of an obsolete breaker type that is prioritized**
3 **for replacement by the Breaker Replacement Program?**

4 A140. Yes. H-breakers are an obsolete oil breaker design, amongst the oldest in the utility
5 industry, dating back to at least the 1920s. H-breakers are no longer manufactured, and
6 replacement parts are not available in the market for them. The Company has replaced
7 twenty-six obsolete H-breakers with modern breakers over the last six years.

8

9 **Q141. How many Breakers have been replaced through the Breaker Replacement**
10 **program in 2023 and prior years?**

11 A141. Please see Table 23.

12

13

Table 23. Breakers Replaced 2018-2023

Breaker Type	2018	2019	2020	2021	2022	2023
Distribution Breakers	31	19	20	22	15	16
Subtransmission Breakers	14	9	7	4	12	6
H-Breakers	5	7	6	3	2	3
Substation Reclosers	6	7	4	10	5	4
Total Breakers	56	42	37	39	34	29
Capital Investment (\$ thousands)	\$9,919	\$9,148	\$10,931	\$17,365	\$14,415	\$13,161

14

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1 **Q142. Why is the forecasted amount in Exhibit A-12, Schedule B5.4 for Breaker**
2 **Replacement \$0 in 2024 and 2025?**

3 A142. Because the Commission approved the Company's Infrastructure Recovery
4 Mechanism (IRM) in Case No. U-21297, and URD Replacement investments are
5 addressed through that mechanism, the investments for Breaker Replacement have
6 been moved from Exhibit A-12, Schedule B5.4 to the IRM Exhibit A-33 Schedule X1.

7

8 **Mobile Fleet Program**

9 **Q143. What is the Mobile Fleet Program?**

10 A143. These investments expand the fleet of mobile generation which is used to quickly
11 restore power to customers during major events such as substation failures. These assets
12 include portable generators, portable switchgear, portable substations, portable ISO
13 equipment, portable poles, energy storage trailers and the controls that allow these
14 assets to work together cohesively during planned and emergency events. This mobile
15 equipment offers multiple operational benefits including decreasing restoration time
16 during substation failures for substation load that can't be fed from adjacent
17 substations/circuits, supporting substations on a single contingency to avoid outages,
18 and providing the ability to facilitate the repairs of the failed equipment inside the
19 substation while customers remain energized. Mobile Fleet Program equipment is also
20 used to support customers during planned construction work when field crews must
21 deenergize electric equipment to allow for work to be performed in a safe manner.

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Figure 29. Portable Substation (left) & Mobile Generator (right)



3

4 **Q144. How does the Mobile Fleet Program benefit customers?**

5 A144. Since the beginning of 2022, DTEE has experienced 96 major events on the system.

6 These events have caused loss of power for anywhere from a few hundred customers
7 to over 10,000 customers. One example of a major event in 2023 occurred at Snover
8 substation, a single transformer, two circuit substation. The single substation
9 transformer failed, resulting in loss of load for nearly 1,100 customers for
10 approximately 13 hours. The load of the circuits could not be transferred to neighboring
11 circuits due to the configuration of adjacent DTEE circuits and because the other
12 adjacent circuits are owned by other electric providers. The Company's short-term
13 solution was to deploy portable distributed generators to serve the load of the two
14 circuits. The medium-term solution required the Company to install a portable
15 substation while permanent repairs were made at Snover substation. This example
16 highlights both the significant challenges to addressing a major event failure and the
17 important role the Mobile Fleet Program plays in restoration of service to customers.

18

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1 In addition, the mobile fleet equipment allows the Company to perform planned work,
2 such as preventative maintenance on single-tap substations, without requiring
3 customers to experience an outage while the work is being performed.
4

5 **Q145. What Mobile Fleet Program equipment is the Company planning to purchase in**
6 **this instant case?**

7 A145. The Company began building the infrastructure around the engine and generator for
8 PDG1 (Portable Distributed Generator), constructed small switching trailers,
9 performed controls work on portable switchgear, and installed controls enhancement
10 on PDG3 units in 2023.
11

12 The Company plans to complete the building of PDG1, perform the integration of
13 portable generator controls to enhance functionality, complete portable switchgear, and
14 install synchrophasor time-based trips for generators in 2024.
15

16 The Company plans to perform integration of portable controls, purchase of additional
17 connection skids, convert hybrid DC generator to a low carbon generator, and phase
18 balance controls in 2025.
19

20 **Pontiac Vaults**

21 **Q146. What is the current state of the Company's infrastructure that provides service**
22 **to the City of Pontiac?**

23 A146. DTEE acquired the electrical system that services the main portion of the City of
24 Pontiac in the 1980s from Consumers Energy. Pontiac is served by an 8.3kV system
25 fed by four substations (Barlett, Paddock, Rapid Street, and Stockwell) and 18

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1 distribution circuits. This portion of the system is surrounded entirely by 13.2kV
2 circuits, so that in the event of a major failure, the Company is unable to quickly restore
3 customers by transferring load to adjacent DTEE circuits.

4

5 The 8.3kV system uses a non-standard voltage that the Company does not use in any
6 other area of its service territory and is an obsolete system. Replacement parts are no
7 longer available for 8.3kV breakers and other substation equipment due to their
8 obsolescence, leading to extended customer interruptions, and leaving the system in an
9 abnormal state for longer durations when work must be completed (preventative or
10 reactive). Additionally, the City of Pontiac has seen a gradual increase in load demand
11 over the past several years. In response to these factors, the Company has created a
12 plan to convert the four 8.3kV substations (and corresponding distribution circuits) to
13 13.2kV, as detailed in Company Witness Deol's testimony.

14

15 The Pontiac 8.3kV system includes underground vaults which contain electrical
16 equipment, such as sectionalizing equipment and service transformers, since the
17 footprint necessary for this infrastructure is not available above ground. These vaults
18 primarily house the equipment that provides service to the downtown business district,
19 which includes hospitals and City of Pontiac official buildings.

20

21 **Q147. What is included in the Pontiac Vaults program?**

22 A147. The Pontiac Vault Program performs upgrades on the existing underground equipment
23 with modern equipment that is submersible and arc sealed. This work includes
24 replacing damaged vaults, replacing at-risk and end-of-life equipment in the vaults,

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1 replacing 7 miles of existing non-standard cable, and installing SCADA monitoring
2 equipment.

3

4 **Q148. How does the Pontiac Vault Program benefit customers?**

5 A148. The customers benefit from this investment because it is an integral part of the greater
6 8.3kV conversion initiative that will improve reliability, allow for faster outage
7 restoration, and increase electric capacity available to serve the City of Pontiac.
8 Additionally, the Pontiac Vaults program replaces at-risk, aging, non-standard
9 equipment that poses a reliability risk to downtown Pontiac and a safety hazard to the
10 Company operators and to the public in the vicinity of the vaults.

11

12 **Q149. What work is the Company planning to complete in this instant case?**

13 A149. In 2023, the Company completed the following construction: Installed conduit and
14 cable, made appropriate repairs to the vault structures, installed a light post and radio,
15 and the loads transfer to energize the Cesar-Chavez Vault; and installed cable between
16 the Huron Vault and the -3 transformer.

17

18 **40kV: Automatic Pole-Top Switch**

19 **Q150. What are Automatic Pole-Top Switches (APTS)?**

20 A150. The function of the APTS is to sectionalize, isolate, or connect portions of the
21 subtransmission system. Failure of one of these switches has the potential to interrupt
22 thousands of customers or result in significant operational constraints. The Company
23 has identified APTS currently installed in the distribution system that are no longer
24 working properly or at risk of failure, and where replacement parts are no longer
25 available due to obsolescence.

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2 **Q151. How does the 40kV: APTS Program benefit customers?**

3 A151. When customer outages occur on the system, if one of these APTS devices is not
4 working properly, it can cause an extended outage for thousands of customers. This
5 program ensures the APTS in the field will operate properly when necessary, so that
6 these devices can reduce the size and impact of multiple customer outages and increase
7 reliability the customers experience.

8

9 **Q152. How many APTS is the Company planning to replace for the investments included**
10 **in the instant case?**

11 A152. In 2023, the Company replaced 10 APTS. The Company plans to replace 12 APTS in
12 both 2024 and 2025.

13

14 **Disconnect and Switcher Replacement**

15 **Q153. What are Disconnects and Switchers?**

16 A153. Subtransmission disconnect switches (“Disconnects”) are used to sectionalize and
17 provide isolation points on the electrical system for operational reasons and/or to enable
18 service and maintenance. Failures of disconnects during operation, when operators
19 attempt to open or close a disconnect manually, can lead to safety concerns, reduce
20 system operability, and force additional equipment to be taken out of service to allow
21 critical work to continue.

22

23 Circuit switchers (“Switchers”) connect the transmission system (120kV) and the
24 subtransmission system (40kV) to the primary side of a substation power transformer.

25 The purpose of circuit switchers is to protect substation equipment from damage caused

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1 by excess fault current. Circuit switchers are a smaller, less expensive alternative to
2 circuit breakers. The Company uses circuit switchers exclusively for transformer
3 protection when performing new construction except in situations that require breakers,
4 such as when reclosing function is required, and if the available fault current exceeds
5 the capacity of switchers.

6

7 **Q154. How does the Disconnects and Switchers Program benefit customers?**

8 A154. The Company replaces disconnects and switchers that have been identified as at-risk,
9 and/or have been identified as being undersized compared to the current fault currents,
10 making them no longer capable of providing proper protection to transformers. These
11 replacements help to protect the Company's operators while manually operating the
12 equipment, allow the Company to sectionalize the system (thus reducing the size and
13 impact of customer outages) when performing work, and to protect the other substation
14 equipment from damage when excess fault current occurs.

15

16 **Q155. How many disconnects and switchers is the Company planning to replace in this**
17 **instant case?**

18 A155. The Company replaced 24 disconnects in 2023 and plans to replace 23 disconnects in
19 both 2024 and 2025.

20

21 The Company replaced 4 switchers in 2023 and plans to replace 6 switchers in both
22 2024 and 2025.

23

24 **Steel Pole Highway Crossings**

25 **Q156. What is the Steel Pole Highway Crossings Program?**

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1 A156. The Company has experienced incidents where wood poles have failed and fallen into
2 highways and caused shutdowns. The Steel Pole Highway Crossing program identifies
3 current wood pole locations where the overhead wire crosses a highway and have a
4 high risk of failure, and replaces these at-risk wood poles with steel poles to reduce the
5 likelihood of pole failures that can impact traffic and public safety and cause customer
6 outages.

7

8 **Q157. How does the Steel Pole Highway Crossings Program benefit customers?**

9 A157. This program was developed to replace high-risk wood poles with steel poles, primarily
10 to reduce the risk of overhead equipment falling and disrupting the highway system of
11 southeastern Michigan, however this also provides an ancillary reliability benefit as
12 failed poles can result in customer outages.

13

14 **Q158. How many Steel Pole Highway Crossings does the Company plan to complete in**
15 **this instant case?**

16 A158. In 2023, the Company installed 4 Steel Pole Highway Crossings, and plans to complete
17 6 crossings in both 2024 and 2025.

18

19 **Batteries and Chargers Replacement Program**

20 **Q159. What are Batteries and Chargers?**

21 A159. The Company's substations utilize batteries and chargers to provide reliable power
22 necessary to trip equipment such as breakers during fault conditions. Failures of
23 batteries and chargers would result in significantly longer duration faults, greater
24 damage to system equipment, larger outages, and increased hazards due to the inability
25 to clear electrical faults.

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2 **Q160. How does the Batteries and Chargers Program benefit customers?**

3 A160. Batteries and chargers have a finite lifespan and eventually require replacement with
4 new units. The Company identifies batteries and chargers that are at-risk of failure and
5 at end of useful life and selects them for replacement. These devices ensure that
6 substation equipment is protected during fault conditions and can continue to operate
7 properly to maintain reliability.

8

9 **Q161. How many Batteries and Chargers does the Company plan to replace in this**
10 **instant case?**

11 A161. In 2023, the Company replaced 54 batteries and 30 chargers. The Company plans to
12 replace 48 batteries and 27 chargers in both 2024 and 2025.

13

14 **SCADA Pole-Top Device Replacement**

15 **Q162. What are SCADA Pole-Top Devices?**

16 A162. SCADA-enabled pole-top devices, such as overhead three-phase reclosers, are
17 sectionalizing devices that are located at key points on overhead distribution circuits.
18 These devices act like a circuit breaker, opening under detection of high current due to
19 a downstream fault, such as a tree branch across two phases. These devices allow the
20 Electric System Operations Center (ESOC) to remotely reconfigure the grid to restore
21 customers by isolating faults and/or transferring load to adjacent circuits during both
22 planned and unplanned outages.

23

24 **Q163. How does replacing SCADA Pole-Top Devices benefit customers?**

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1 A163. This program replaces devices that have experienced high rates of failure such as Eaton
2 Form 3 reclosers and Bridges pole-top switches (PTS). Failure of these devices reduces
3 system operability, thus increasing the amount of extended duration outages for
4 customers. Replacing these identified devices allows the ESOC to operate the system
5 more effectively, reducing the number and duration of outages experienced by
6 customers.

7

8 **Q164. How many SCADA Pole-Top Devices does the Company plan to replace in this**
9 **instant case?**

10 A164. In 2023, the Company replaced 19 SCADA pole-top devices. The Company plans to
11 replace 20 SCADA pole-top devices in both 2024 and in 2025.

12

13 **Substation Regulator Replacement**

14 **Q165. What are Substation Regulators?**

15 A165. Substation regulators are devices that ensure voltages stay within the normal ranges for
16 which Company and customer equipment is rated to perform. Voltage regulation is
17 critical to maintaining the health of electric equipment and helps to maintain the service
18 life of this equipment.

19

20 **Q166. How does replacing Substation Regulators benefit customers?**

21 A166. Voltage regulation is essential to maintain the health and operability of electrical
22 equipment and prevents the premature damage and failure of this equipment, thus
23 reducing outages customers experience.

24

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1 **Q167. How many Substation Regulators does the Company plan to replace in this instant**
2 **case?**

3 A167. In 2023, the Company replaced 4 substation regulators. The Company plans to replace
4 3 substation regulators in both 2024 and 2025.

5

6 **Portable Generators**

7 **Q168. What is the Portable Generator Program?**

8 A168. The Portable Generator Program is an investment the Company is undertaking to help
9 reduce the length of extended outages to single customers during storm events. In
10 short, the Company has purchased portable generators that can be dispatched and
11 serviced to single customers to help energize critical devices such as refrigerators,
12 freezers, personal medical devices, and sump pumps in the event they are expected to
13 be out of service for an extended period during large storms. This program is discussed
14 in more detail in Company Witness Hill's testimony.

15

16 **Q169. Does this complete your direct testimony?**

17 A169. Yes, it does.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-21534

| REVISED REBUTTAL TESTIMONY

OF

MORGAN ELLIOTT ANDAHAZY

DTE ELECTRIC COMPANY**REVISED REBUTTAL TESTIMONY OF MORGAN ELLIOTT ANDAHAZY**Line
No.

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

3 A1. My name is Morgan Elliott Andahazy (she/her/hers). My business address is One
4 Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate
5 Services, LLC, a subsidiary of DTE Energy Company.

6

7 **Q2. Did you file revised direct testimony in this proceeding on behalf of DTE**
8 **Electric 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 Witnesses Alvarez and
14 Stephens on behalf of the Attorney General (AG), Michigan Environmental
15 Council (MEC), and Natural Resources Defense Council (NRDC), collectively
16 referred to as “AG-MN”. The absence of a discussion of other matters in my
17 rebuttal testimony should not be taken as an indication of agreement with other
18 aspects of any intervenor’s testimony.

19

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

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

<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
22 A-51	PP1	Discovery Response: U-21534 MNSCDE-15.34b
23 A-51	PP2	NDA Discovery Response: U-21534 MNSCDE-
24		15.34b-01 4.8kV Hardening Program Cost per Mile
25		

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1			Analysis
2	A-51	PP3	Discovery Response: U-21534 MNSCDE-15.37
3	A-51	PP4	NDA Discovery Response: U-21534 MNSCDE-
4			15.37-01 PTMM Program Investment per Mile
5			Analysis
6	A-51	PP5	Discovery Response: U-21534 MNSCDE-15.38a
7	A-51	PP6	NDA Discovery Response: U-21534 MNSCDE-
8			15.38a-01 URD Program Investment per Thousand
9			Feet Analysis
10	A-51	PP7	Discovery Response: U-21534 MNSCDE-15.47a
11	A-51	PP8	NDA Discovery Response: U-21534 MNSCDE-
12			15.47a-01 Breaker Program Investment per Breaker
13			Analysis
14	A-51	PP9	Discovery Response: U-21534 MNSCDE-3.6-01
15			4.8kV Hardening Data.xlsx
16	A-51	PP10	NDA Discovery Response: U-21534 MNSCDE-
17			3.10b
18	A-51	PP12	Discovery Response: U-21534 MNSCDE-15.24
19	A-51	PP13	Discovery Response: U-21534 MNSCDE-12.5b
20			Pole Standards
21	A-51	PP14	Discovery Response: U-21534 MNSCDE-12.5c

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 twenty specific points I will rebut in my testimony, as listed below. A
3 discussion of why the intervenor's recommendations should not be accepted by the
4 Commission follows.

5

6 Rebuttal Contents

7	Purpose of Testimony	1
8	Strategic Capital Governance	5
9	Rebuttal Issue 1: AG-MN Witness Alvarez's inaccurate claims concerning the	
10	Company's strategic capital program governance.	5
11	4.8kV Hardening Program	7
12	Rebuttal Issue 2: AG-MN Witness Stephens's inaccurate assessment that 4.8kV	
13	Hardening Program wire down benefits are overstated.	7
14	Rebuttal Issue 3: AG-MN Witness Stephens's assertion that 4.8kV Hardening Program	
15	benefits are overstated due to the composition of its control group.	8
16	Rebuttal Issue 4: AG-MN Witness Stephens's inaccurate claim that the 4.8kV	
17	Hardening Program scope is redundant with Tree Trimming and PTMM.	11
18	Table 1 – All-Weather Customer Interruptions Excluding MEDs 3-years avg. before	
19	vs. 3-years avg. after	13
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1 **Strategic Capital Governance**

2 Rebuttal Issue 1: AG-MN Witness Alvarez's inaccurate claims concerning the
3 Company's strategic capital program governance.

4 **Q7. Can you summarize your assessment of AG-MN Witness Alvarez's claims**
5 **about the Company's strategic capital program governance?**

6 A7. While not directly stating so, AG-MN Witness Alvarez testimony (pages 27-28)
7 appears to imply that all the referenced strategic capital programs are allocated a
8 budget at the program level with no expectation of how many circuit miles or units
9 of work are expected to be completed. He has also drawn the conclusion that the
10 Company does not track actual circuit miles or units completed by the programs
11 and is therefore unable to support benefit projections.

12

13 **Q8. Do you agree with AG-MN Witness Alvarez's assessment?**

14 A8. No. AG-MN Witness Alvarez's testimony concerning capital governance is more
15 comprehensively rebutted by Company Witness Kryscynski. However, I wish to
16 briefly rebut the specific topic of program work units and explain how they are
17 planned and tracked. I disagree with AG-MN Witness Alvarez's argument that
18 strategic capital programs do not establish targets for circuit miles or units of work
19 to be completed for the annual budgets they are allocated and that the Company
20 cannot therefore track program performance.

21

22 **Q9. Are the Company's programs managed with expectations for how many work**
23 **units they will perform within their budget?**

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1 A9. Yes. The Company's programs are allocated a budget (in dollars) and then based
2 on that level of funding the Company develops a targeted quantity of circuit miles
3 and/or work units to be completed.

4

5 The Company provided budget versus actual capital investment and planned versus
6 actual work units in the following discovery responses:

- 7 • NDA U-21534 MNSCDE-15.34b-01 4.8kV Hardening Program Cost per
8 Mile Analysis¹
- 9 • NDA U-21534 MNSCDE-15.37-01 PTMM Program Investment per Mile
10 Analysis²
- 11 • NDA U-21534 MNSCDE-15.38a-01 URD Program Investment per
12 Thousand Feet Analysis³
- 13 • NDA U-21534 MNSCDE-15.47-01 Breaker Program Investment per
14 Breaker Analysis⁴

15

16 **Q10. Has the Company provided information concerning work units for its**
17 **Infrastructure Resilience and Hardening programs in testimony in this instant**
18 **case?**

19 A10. Yes. I have included units of work in my revised direct testimony for the following
20 programs:

- 21 • 4.8kV Hardening: page 20, table 3 and page 22, table 4
- 22 • PTMM: page 47, table 10 and page 53, table 12
- 23 • Frequent Outage Programs (CEMI): page 80, lines 1-3 and table 13

¹ Exhibit A-51, Schedule PP1 and Exhibit A-51, Schedule PP2

² Exhibit A-51, Schedule PP4

³ Exhibit A-51, Schedule PP5 and Exhibit A-51, Schedule PP6

⁴ Exhibit A-51, Schedule PP7 and Exhibit A-51, Schedule PP8

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- 1 • Cable Replacement: page 92, table 16
- 2 • URD Replacement: page 100, table 21
- 3 • Breaker Replacement: page 105, table 23
- 4 • 40kV Automatic Pole-Top Switch: page 111, lines 11-12
- 5 • Disconnects and Switchers: page 112, lines 18-22
- 6 • Steel Pole Highway Crossings: page 113, lines 16-17
- 7 • Batteries and Chargers: page 114, lines 11-12
- 8 • SCADA Pole-Top Device Replacement: page 115, lines 10-11
- 9 • Substation Regulators: page 116, lines 3-4

10

11 **4.8kV Hardening Program**

12 Rebuttal Issue 2: AG-MN Witness Stephens's inaccurate assessment that 4.8kV
 13 Hardening Program wire down benefits are overstated.

14 **Q11. What does AG-MN Witness Stephens say with regards to the Company**
 15 **overstating 4.8kV Hardening benefits?**

16 A11. AG-MN Witness Stephens, on page 10, line 20 and page 11, lines 1-9, states, "...
 17 while the removal of DPLD wire, which is no longer used and is thus less likely to
 18 be maintained, eliminates the risk that an energized *DPLD* wire will fall to the
 19 ground, it does NOT eliminate the risk that an energized *DTE* conductor will fall to
 20 the ground and not be deenergized, given that the hardening program does not
 21 eliminate the fact that there is no neutral wire on the 4.8kV system. In its requests
 22 for approval of large amounts of funding for the 4.8kV Hardening program in prior
 23 cases, DTE may have created an exaggerated impression of the safety benefits of
 24 the 4.8kV Hardening program. It does not appear that DTE discouraged any

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1 exaggerated impression of safety benefit in the Technical Conference workshop
2 DTE hosted on March 22, 2023.”

3

4 **Q12. Has the Company exaggerated wire down reduction or claimed that the 4.8kV**
5 **Hardening Program eliminates all risk of wire downs?**

6 A12. No. While I agree with AG-MN Witness Stephens’s assertion that the 4.8kV
7 Hardening Program eliminates the risk of DPLD arc wire downs, the Company has
8 not claimed that 4.8kV Hardening completely eliminates the risk of wire downs of
9 DTE Electric’s overhead conductor. However, the Company has accurately stated
10 that the improvements made by this program reduces this risk.

11

12 In my revised direct testimony on page 26, in Figure 5, the Company provides
13 analysis that shows a 25% reduction in wire down events on hardened circuits when
14 comparing the three-year average before hardening to the one-year after. This 25%
15 reduction in wire downs is based on actual performance data.

16

17 Rebuttal Issue 3: AG-MN Witness Stephens’s assertion that 4.8kV Hardening
18 Program benefits are overstated due to the composition of its control group.

19 **Q13. What does AG-MN Witness Stephens’s say with regards to the control group**
20 **used to calculate benefits for the 4.8kV Hardening Program?**

21 A13. AG-MN witness Stephens says the following on page 9, lines 1-5 of his testimony,
22 “... the Company appropriately employs a “difference of differences” approach to
23 quantifying reliability improvements from various capital programs using “test”
24 and “control” groups of circuits. But the Company’s control group definition

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1 dramatically exaggerates reliability improvements from capital programs by
2 eliminating tree trimming...”

3

4 **Q14. Do you agree with AG-MN Witness Stephens that the control group**
5 **exaggerates benefits received from the 4.8kV Hardening Program?**

6 A14. No. The intent of this comparison was to show the benefits of 4.8kV Hardening
7 versus a “do-nothing scenario.” This methodology was also used in Case Nos. U-
8 20836 and U-21297 in addition to this instant case.

9

10 For All-Weather ~~SAIDI~~ SAIFI benefits, Figure 3 on page 24 of my revised direct
11 testimony shows:

- 12 • 38% improvement when comparing three-year average performance before
13 hardening versus one-year after hardening;
- 14 • In a separate chart, it also shows a 23% worsening when comparing three-
15 year average performance before versus one-year after for the control group
16 (4.8kV circuits which have not been hardened or tree trimmed recently).

17

18 The net performance of both hardened and control group circuits is used to derive
19 a total improvement of 61% for hardened circuits on page 25, lines 1-4.

20

21 For SAIDI excluding MEDs benefits: Figure 4 on page 25 of my revised direct
22 testimony shows:

- 23 • 65% improvement in SAIDI excluding MEDs when comparing three-year
24 average performance before hardening versus one-year after hardening;

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- 1 • In a separate chart, it also shows a 3% improvement when comparing three-
- 2 year average performance before versus one-year after for the control group
- 3 (4.8kV circuits which have not been hardened or tree trimmed recently).

4

5 The net performance of both hardened and control group circuits is used to derive

6 a total improvement of 62% for hardened circuits on page 25, lines 7-10.

7

8 For wire down benefits: Figure 5 on page 26 of my revised direct testimony shows:

- 9 • 25% improvement in wire down events when comparing three-year average
- 10 performance before hardening versus one-year after hardening,
- 11 • In a separate chart, it also shows a 22% worsening when comparing three-
- 12 year average performance before versus one-year after for the control group
- 13 (4.8kV circuits which have not been hardened or tree trimmed recently).

14

15 The net performance of both hardened and control group circuits is used to derive

16 a total improvement of 47% for hardened circuits on page 26, lines 3-6.

17

18 The presented data shows that the All-Weather SAIFI, SAIDI excluding MEDs,

19 and wire down event improvements (even when ignoring the control group) from

20 the 4.8kV Hardening Program are significant and show clear and compelling

21 benefits to customers. The Company's presentation of these analyses enables the

22 Commission to make its ruling by either considering hardened circuits before-and-

23 after performance alone or by also considering the control group performance in

24 comparison.

25

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1 Rebuttal Issue 4: AG-MN Witness Stephens's inaccurate claim that the 4.8kV
2 Hardening Program scope is redundant with Tree Trimming and PTMM.

3 **Q15. What does AG-MN Witness Stephens say concerning the redundancy of the**
4 **4.8kV Hardening Program when compared to the PTMM and Tree Trimming**
5 **Programs?**

6 A15. AG-MN Witness Stephens makes two claims implying the 4.8kV Hardening scope
7 is redundant in his testimony:

- 8 • “DTE is required to complete the tree trimming in any event, meaning that
9 the reliability benefits from tree trimming should not be credited to the
10 4.8kV Hardening program.” (page 13, lines 2-4).
11 • “... replacing crossarms when defects are identified is part of the pole top
12 maintenance program in any event.” (page 12, lines 4-5).

13

14 **Q16. Do you agree that the Tree Trim and PTMM Programs make the 4.8kV**
15 **Hardening Program work redundant?**

16 A16. No. The Company disagrees with AG-MN Witness Stephens's implications that the
17 4.8kV Hardening Program is redundant because PTMM and Tree Trimming will
18 be performed on the circuits regardless.

19

20 First, it is important to note that circuits which are within the 4.8kV Hardening
21 Program scope are currently excluded from the scope of the PTMM Program. There
22 is no redundancy between the programs, and hardened circuits will later have
23 PTMM performed on them at an appropriate time in future PTMM cycles.

24

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1 Second, tree trimming is required to allow crews safe and efficient access to
2 equipment. It is not redundant to trim circuits being hardened. The 4.8kV
3 Hardening Program coordinates its work with the Tree Trimming Program and
4 circuits are trimmed before 4.8kV Hardening work begins. Hardened circuits will
5 be later tree trimmed again at an appropriate time in the maintenance tree trimming
6 cycle.

7

8 **Q17. Is there anything else you would like to add for context concerning the 4.8kV**
9 **Hardening Program as compared to the Tree Trimming Program?**

10 A17. Yes. I would also like to state that these programs are complementary in nature and
11 not direct replacements for each other.

12

13 While tree trimming is clearly a beneficial program and is necessary to continue,
14 trimming trees alone does not improve the condition of poles and pole-top
15 equipment. Replacing defective poles and pole-top equipment with newer and
16 stronger designs and materials improves the grid's ability to avoid wire downs and
17 outages from inclement weather and tree impacts. The Company is six years into
18 its Tree Trimming Surge and had 83% of its circuits on-cycle as of year-end 2023.
19 If reliability was only driven by the need for tree trimming as AG-MN Witness
20 Stephens seems to suggest, this is contradicted by the Company experiencing two
21 of its worst storm years in 2021 and 2023.

22

23 The Company presented analysis in discovery response U-21534 MNSCDE-3.6-01
24 4.8kV Hardening Data.xlsx (Exhibit A-51, Schedule PP9) which demonstrates that

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1 the 4.8kV Hardening Program provides significant safety and reliability benefits
 2 three years after work is performed (Tables 1, 2, and 3).
 3

4 **Table 1 – All-Weather Customer Interruptions Excluding MEDs 3-**
 5 **years avg. before vs. 3-years avg. after**

4.8kV Hardening	3-years Avg. Before All-Weather Customer Interruptions	3-years Avg. After All-Weather Customer Interruptions	Difference (Better) / Worse	% (Improvement) / Worsening
Circuits Hardened 2018-2020	124,353	70,123	(54,230)	(44%)
Control Group 2018-2020	692,879	882,197	189,318	27%

6
 7 **Table 2 – Customer Minutes Interrupted Excluding MEDs 3-years avg.**
 8 **before vs. 3-years avg. after**

4.8kV Hardening	3-years Avg. Before Customer Minutes Interrupted Excl. MEDs	3-years Avg. After Customer Minutes Interrupted Excl. MEDs	Difference (Better) / Worse	% (Improvement) / Worsening
Circuits Hardened 2018-2020	16,900,510	5,654,200	(11,246,309)	(67%)
Control Group 2018-2020	114,271,545	94,710,157	19,561,388	17%

9

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Table 3 – Wire Down Events 3-years avg. before vs. 3-years avg. after

4.8kV Hardening	3-years Avg. Before Wire Down Events	3-years Avg. After Wire Down Events	Difference (Better) / Worse	% (Improvement) / Worsening
Circuits Hardened 2018-2020	1,624	1,099	(525)	(32%)
Control Group 2018-2020	9,892	11,307	1,415	14%

2

3 Please note that these 3-year average before and 3-year average after calculated
 4 benefits are even higher than the 3-year average before and 1-year after benefits
 5 shown in my revised direct testimony. Please also note that this analysis includes
 6 the years 2021 and 2023 which were historic storm years when overall system
 7 reliability experienced the greatest impacts. Taking all these factors into account, it
 8 is clear that some of the Company's most vulnerable customers in and around the
 9 city of Detroit have received significant and persistent safety and reliability benefits
 10 as a result of the 4.8kV Hardening Program.

11

12 Rebuttal Issue 5: AG-MN Witness Stephens's inaccurate claim that DPLD Arc Wire
 13 Removal alone provides nearly all the safety benefits at half the cost of 4.8kV
 14 Hardening Program.

15 **Q18. What does AG-MN Witness Stephens assert concerning DPLD Arc Wire**
 16 **Removal?**

17 A18. On page 11, lines 12-17, AG-MN Witness Stephens states, "Removing the DPLD
 18 wire alone will provide almost all of the safety benefits of the 4.8kV Hardening
 19 program at greatly reduced cost, and with a greater deployment speed. The marginal

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1 added safety benefits of the 4.8kV Hardening program over the option to simply
2 remove the DPLD wire are due to two extra steps the 4.8kV Hardening program
3 takes over the “remove DPLD Only” option to reduce the risk that DTE conductor
4 will fall to the ground.”

5
6 **Q19. Do you agree that DPLD Arc Wire Removal alone will provide nearly all of**
7 **the benefits of the 4.8kV Hardening Program at a much lower cost?**

8 A19. No. The March 22, 2023, 4.8kV Technical Conference Presentation (Technical
9 Conference) (Exhibit A-23, Schedule M12, page 39) that Witness Stephens
10 references on page 12 of his testimony states that DPLD Arc Wire Removal would
11 provide approximately 50% as much benefit for approximately 55% as much of the
12 investment required for the 4.8kV Hardening Program (Table 4).

13

14

Table 4 – 4.8kV Technical Conference Benefits⁵

When comparing the alternative approaches, the 4.8kV Hardening program was selected originally because it strikes a balance between cost, reliability, and the timely removal of the arc wire from the DTE Electric system

	Cost per mile ¹	Wire down Reduction	SAIFI Reduction ²	CAIDI Reduction ³	Capacity Increase	Increase DER Usage	Execution Complexity	Potential Use Case
Arc Wire Removal	\$191K	13%	22%	36%	No	No	Low	Lowest overall cost to remove arc wire
4.8kV Hardening	\$353K	26%	44%	72%	No	No	Low	Highest benefit/cost for reliability improvement
Pre-conversion	\$1.7M	90%	85%	85%	No	Yes	Medium	Provides step change in reliability performance
Conversion	\$2.7M	90%	85%	85%	Yes	Yes	High	Best benefit/cost for significant capacity needs
Microgrids	\$14.6M	90%	95%	95%	Yes	Yes	Very High	Potentially application for grid areas with critical reliability needs

DTE

1. Median of cost range
2. SAIFI measures the frequency of customer interruptions
3. CAIDI measures the duration of customer interruptions

39

⁵ Please note that the header saying “CAIDI Reduction” in the 4.8kV Hardening Technical Conference Presentation should have been labeled “SAIDI Reduction”.

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1 **Q20. Do you agree that the only difference between 4.8kV Hardening and DPLD**
2 **Arc Wire Removal is “two extra steps” as alleged by Witness Stephens?**

3 A20. No. If a program was developed to narrowly limit its scope to DPLD arc wire
4 removal, the only poles and pole-tops which would have been inspected and
5 addressed were those which are collocated with DPLD arc wire (approximately half
6 as many circuit miles as under the 4.8kV Hardening Program).

7

8 The 4.8kV Hardening Program scope includes the following differences from the
9 DPLD Arc Removal option:

10 1. More intensive tree trimming (removal of all overhanging vegetation
11 and an additional 10 feet of clearance) and on twice as many circuit
12 miles,

13 2. Pole-top inspection and replacement on twice as many circuit miles,

14 3. Pole inspection and replacement on twice as many circuit miles,

15 4. Removal of abandoned service lines (reduces wire down risk),

16 5. Primary deconductoring in abandoned areas (reduces wire down risk).

17

18 Rebuttal Issue 6: AG-MN Witness Stephens’s assertion that work performed under
19 the 4.8kV Hardening Program are redundant due to later conversions to 13.2kV.

20 **Q21. What does AG-MN Witness Stephens assert with regards to 4.8kV Hardening**
21 **work being made redundant when the circuits are later converted to 13.2kV?**

22 A21. On page 14, lines 6-11, AG-MN Witness Stephens says “... most of the work
23 completed under the 4.8kV Hardening program (other than full tree trimming,
24 which must be completed irrespective of hardening) will be rendered redundant
25 when a 4.8kV circuit that has been hardened is converted to a 13.2kV circuit. DTE

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1 cannot justify the installation of fiberglass crossarms with a service life likely in
2 excess of 50 years on a circuit DTE aims to convert to 13.2kV in the next 15 years
3 or so.”

4

5 **Q22. Does the Company’s plan to convert 4.8kV circuits to 13.2kV invalidate the**
6 **investments being made in 4.8kV Hardening?**

7 A22. No. The 4.8kV Hardening Program coordinates with the 4.8kV Conversion
8 Program to ensure that circuits selected for near-term conversion (five-years) are
9 not hardened and the circuits that were selected for 4.8kV Hardening that are not
10 expected to see significant load growth are therefore unlikely to be prioritized for
11 conversion.

12

13 Per Company Witness Deol’s rebuttal testimony:

- 14 • “The 15-year conversion goal is a directional target and may change in
15 timing and priority as specific grid needs evolve in different geographic
16 areas and circuits.” (Page 7, lines 4-5)
- 17 • “Ultimately, the grid will be rebuilt at a pace required to support customer
18 needs and affordability. The conversion investments in this case are
19 supported by near-term drivers highlighted in my testimony, such as
20 capacity needs, reliability improvements, and addressing aging and end of
21 life infrastructure.” (Page 7, lines 17-21)

22

23 The pole-top equipment utilized by the 4.8kV Hardening Program is equivalent to
24 the equipment used for 13.2kV circuit configurations. The Company’s engineers

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1 will assess how much of the installed equipment can be retained for conversion to
2 13.2kV when these hardened circuits are selected for conversion in the future.
3 The Company believes it is reasonable and prudent to perform necessary work now
4 to improve safety and reliability for some of its most vulnerable customers in and
5 around the city of Detroit.

6

7 Rebuttal Issue 7: AG-MN Witness Stephens's incorrect statement that DTE Electric
8 selected the 4.8kV Hardening Program to increase its capital investment.

9 **Q23. What does AG-MN Witness Stephens say concerning the Company's selection**
10 **of the 4.8kV Hardening Program?**

11 A23. AG-MN Witness Stephens states on page 13, lines 14-15, "It may be because the
12 4.8kV Hardening program grows DTE's rate base at almost twice the cost per mile
13 as the DPLD wire removal only option."

14

15 **Q24. Was the 4.8kV Hardening Program selected over DPLD Arc Wire Removal**
16 **only to increase the Company's capital return?**

17 A24. No. The Company selected the 4.8kV Hardening Program to maximize benefits to
18 customers when considering the fixed costs associated with planning and managing
19 the work as well as mobilizing and demobilizing crews. 4.8kV Hardening Program
20 scope was designed to eliminate DPLD arc wire downs, reduce DTE Electric
21 distribution wire downs, increase reliability for customers, remove abandoned
22 service lines, and perform deconductoring in abandoned areas. Additional scope
23 beyond only removing DPLD arc wire was added to take advantage of the fact that
24 crews would already be mobilized to perform work on the circuits and because
25 customers would receive increased benefits from the added scope.

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2

Rebuttal Issue 8: AG-MN Witness Stephens's recommendation that 4.8kV

3

Hardening should be suspended until a BCA is performed that shows the program

4

benefits exceed the incremental costs when compared to DPLD Arc Wire Removal.

5

Q25. What does AG-MN Witness Stephens say concerning the need for a BCA to support the 4.8kV Hardening Program?

6

7

A25. AG-MN Witness Stephens says on page 13, lines 15-18, "What is needed is a risk-informed benefit-cost analysis showing that the dollar value of the incremental reliability and safety benefits of the 4.8kV Hardening program over the DPLD wire removal only option exceeds the incremental cost of the 4.8kV Hardening program."

11

12

13

Additionally, on page 13, line 21 and page 14, lines 1-3, "I recommend such an

14

approach be used to complete a benefit-cost analysis before the Commission

15

determines that the 4.8kV Hardening program provides greater safety and

16

reliability benefits per dollar than the option of removing the DPLD wire only."

17

18

Q26. Does the Company agree that a BCA should be performed for the 4.8kV Hardening Program before the Commission determines it is prudent and reasonable?

19

20

21

A26. No. The 4.8kV Hardening Program is a mature program that has been ongoing since 2018 and is scheduled to be completed in 2026. The Company has provided actual performance data in Case Nos. U-20836 and U-21297 and additionally in this instant case (pages 23 through 26, including Figures 3, 4, and 5 of my revised direct testimony and pages 13 through 14 including Tables 1, 2, and 3 of my rebuttal

22

23

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1 testimony) which show significant and persistent benefits to customers. Suspending
2 the program now to perform a BCA would cause delays and contradict the
3 Commission's order in Case No. U-21297 dated December 1, 2023 on page 93
4 where it directed the Company to accelerate the program, "... completing this work
5 is crucial to the residents and businesses located in areas that contain abandoned
6 arc wire and the Commission agrees with the Staff that the *removal of the arc wire*
7 *should be going faster* [emphasis added]."

8
9 Rebuttal Issue 9: AG-MN Witness Stephens's recommended elimination of and
10 recommended disallowances for the 4.8kV Hardening Program.

11 **Q27. What changes and disallowances does AG-MN Witness Stephens recommend**
12 **for the 4.8kV Hardening Program?**

13 A27. AG-MN Witness Stephens recommends on page 15, lines 1-8, "I recommend the
14 Commission order the Company to eliminate the 4.8kV Hardening program
15 immediately in favor of the "remove DLPD wire only" option. I also recommend
16 the Commission reduce test year spending to the amount required to complete the
17 same number of miles of DLPD wire removal that it would have hardened with the
18 \$80 million requested for 2024. As DLPD wire removal costs 46% less than 4.8kV
19 Hardening per circuit mile, I recommend the Commission reduce the Company's
20 test year capital spending for DLPD wire removal program to \$43.2 million to
21 reflect shift from Hardening to DLPD wire removal only."

22
23 AG-MN Witness Stephens also recommends on page 14, lines 8-12, "I further
24 recommend the Commission disallow \$73.333 million from the bridge period
25 (2024) as a result of DTE's excess spending above what it requested and above

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1 what the Commission approved in U-21297, and for the additional reason that DTE
2 has consistently failed to evaluate and support the efficacy of Hardening
3 independent of tree trimming” as summarized in Table 5.

4

5

Table 5 – AG-MN Proposed Disallowances for the 4.8kV Hardening

6

Program

4.8kV Hardening Program	2024 (\$ thousands)	2025 (\$ thousands)	Source
DTE’s Requested Capital Investment	\$80,000	\$125,000	Exhibit A-12, Schedule B5.4, page 13, line 12
AG-MN Witness Stephens’s disallowances	(\$73,333)	(\$81,800)	AG-MN Witness Stephens’s testimony page 46
AG-MN Witness Stephens’s Proposed Capital Investment	\$6,667	\$43,200	

7

8 **Q28. Should the Company receive a disallowance in 2024 for increasing investment**
9 **in 2023 beyond what was included Case No. U-21297?**

10 A28. No. The Commission in its order dated December 1, 2023, stated the following on
11 page 93, “... completing this work is crucial to the residents and businesses located
12 in areas that contain abandoned arc wire and the Commission agrees with the Staff
13 that the *removal of the arc wire should be going faster* [emphasis added].”

14

15 The Company’s acceleration of the 4.8kV Hardening Program is consistent with
16 the Commission’s stated support.

17

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1 **Q29. Do you have any additional concerns with AG-MN Witness Stephens's**
2 **proposed disallowances for the 4.8kV Hardening Program?**

3 A29. Yes. My first concern is that 4.8kV Hardening Program construction is already
4 underway this year and the program will have completed its 2024 workplan by the
5 time the Commission issues its order for this instant case. It will not be possible to
6 undo this work and the associated investment.

7

8 My second concern is that changing the program to DPLD Arc Wire Removal for
9 2025 would result in lower customer safety and reliability benefits, and would
10 require new work scope packages to be developed, which would delay the removal
11 of DPLD arc wire.

12

13 **Q30. Should the Commission adopt AG-MN Witness Stephens's proposed**
14 **disallowances for the 4.8kV Hardening program?**

15 A30. No. The 4.8kV Hardening Program is a mature program and the Company has
16 demonstrated that this program is reasonable and prudent in Case Nos. U-20162,
17 U-20561, U-20836, and U-21297 and has received Commission support and
18 approval in each of these cases.

19

20 The Company also presented an analysis of alternatives to the 4.8kV Hardening
21 Program in its March 22, 2023 Technical Conference and changes could have been
22 ordered in Case No. U-21297, but instead the Commission reiterated its desire that
23 the Company accelerate and complete the 4.8kV Hardening Program in its order
24 dated December 1, 2023, on page 94, "Finding this work to be imperative, however,
25 the Commission approves the requested bridge period and test year funding and

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1 expects to see results in DTE Electric's next rate case, including an accelerated
2 removal of the arc wire as discussed by the Staff."
3

4 **Pole and Pole Top Maintenance and Modernization Program (PTMM)**

5 Rebuttal Issue 10: AG-MN Witness Stephens's statements on PTMM benchmarking.

6 **Q31. What does AG-MN Witness Stephens say regarding the PTMM**
7 **benchmarking performed?**

8 A31. AG-MN Witness Stephens says on page 25, lines 15-20 and page 26, lines 1-3,
9 "The increase in pole inspection standards appears reasonable, though the move to
10 inspect pole tops (once every five years) more frequently than poles (once every
11 ten years) is not as common as the Company seems to imply. In my experience, it
12 is very common to inspect pole tops at the same frequency as poles, as it reduces
13 inspection costs (because poles and pole tops can be inspected at the same time).
14 While I do not oppose the five-year inspection standard for pole tops, the Company
15 should have undertaken a benefit-cost analysis comparing the increased costs of
16 more frequent inspections to the customer benefits of more frequent inspections
17 (the dollar value to customers of the expected reduction in service interruption
18 frequency) before making the change."
19

20 **Q32. Do you agree with witness Stephens' claim that the Company implied it is**
21 **common for utilities to have different cycles for pole-top and pole inspections?**

22 A32. No. Table 6 on page 33 of my testimony was not intended to be a comprehensive
23 analysis of all utilities, nor to determine how common it is to have different cycles
24 for pole-top and pole inspections. This table covers seven utilities located in the
25 Northeast and Midwest regions. The Company performed this benchmarking to

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1 identify industry best practices. This analysis shows that 10–12-year pole
2 inspection cycles are common and that at least five utilities in nearby states inspect
3 pole-top equipment every 4-5 years.

4

5 Rebuttal Issue 11: AG-MN Witness Stephens’s statements on PTMM standards
6 changes.

7 **Q33. What does AG-MN Witness Stephens say regarding PTMM standards**
8 **changes performed?**

9 A33. AG-MN Witness Stephens says, on page 26, lines 17-23, “In my experience
10 changes to construction standards have historically been preceded by workshops
11 attended by personnel from multiple operating regions and departments. Multiple
12 review rounds of edits to the existing standard are completed as the new standard
13 takes shape. Analyses are completed that estimate the incremental benefits (in
14 dollars) and incremental costs of the change to ensure the change is cost-effective.
15 All this is presented to management for formal review and approval.”

16

17 On page 28, lines 7-10, “The Company failed to provide documentation of such a
18 review or approval despite repeated requests. However, the Company hired an
19 external consultant to complete a cost-benefit analysis after the fact, while DTE
20 was preparing its instant application.”

21

22 **Q34. Did DTE perform internal analyses and cross-functional workshops before**
23 **making changes to inspection and construction standards?**

24 A34. Yes. The Company’s engineers performed analysis, and benchmarking and cross-
25 functional workshops occurred over a large span of time beginning over a decade

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1 ago. While the Company acknowledges that the documentation located and shared
2 for all of these activities during discovery was incomplete, the Company did share
3 documentation demonstrating this work was performed in discovery response U-
4 21534 MNSCE-12.5b (Exhibit A-51, Schedule PP13).

5

6 Please note that page 9 of Exhibit A-51, Schedule PP13 demonstrates that the
7 Company utilizes cross-functional teams when reviewing standards changes.

8

9 Rebuttal Issue 12: AG-MN Witness Stephens's claim that DTE performed the
10 PTMM BCA to justify its standards changes.

11 **Q35. What does AG-MN Witness Stephens say regarding with regards to the**
12 **PTMM BCA being used to justify PTMM standards changes?**

13 A35. AG-MN Witness Stephens states, on page 28, lines 12-13 and page 29, lines 1-4,
14 "DTE solicited a consultant after it decided to increase the pole construction
15 standard, and after hundreds of millions of dollars had already been spent. In my
16 experience, the purpose of completing benefit-cost analyses on spending proposals
17 is to make better decisions regarding those proposals *before* costs are incurred. In
18 this case, a benefit-cost analysis on the PTMM program was completed after the
19 fact in an apparent attempt to retroactively justify the change in standards which
20 DTE had already made."

21

22 **Q36. Do you agree that the Company performed a BCA to retroactively justify its**
23 **standards changes?**

24 A36. No. The changes made to standards were informed by benchmarking and industry
25 research (please see pages 32 through 34 of my revised direct testimony for a

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summary of benchmarking performed). Some of this work included the Company's participation in a three-year research program with the Electric Power Research Institute (EPRI) which culminated in a Distribution Grid Resiliency report⁶ (Exhibit A-51, Schedule PP14). The decision to perform a BCA was made in 2023 after reviewing feedback the Company received from its rate case. The BCA was not performed to justify the Company's standard changes but to demonstrate that the PTMM Program is beneficial to customers.

Rebuttal Issue 13: AG-MN Witness Stephens's concerns with the absence of Company equipment segmented historical failure data in the PTMM BCA Model.

Q37. What does AG-MN Witness Stephens say regarding the absence of equipment segmented historical failure data within the PTMM BCA Model?

A37. AG-MN Witness Stephens states on page 29, lines 6-13, "For example, the Company cannot provide the historical failure rates for crossarms, porcelain cutouts, and porcelain insulators, nor can it identify service interruptions, customer counts, or average durations associated with failures from these equipment types. Clearly, when projecting improvements relative to existing construction standards, an understanding of the baseline service interruption risk is critical to have. Not only does the consultant's PTMM benefit cost analysis fail to employ these values, DTE does not maintain the data required to produce these values."

Q38. Do you agree with the claim by AG-MN Witness Stephens that the PTMM BCA rests on a "weak foundation" because the Company does not have precise

⁶ <https://eprijournal.com/making-distribution-grids-stronger-more-resilient/>

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1 **data on the quantity of customer outages resulting from specific types of pole-**
2 **top equipment failures?**

3 A38. No. 1898 & Co. has assisted nineteen other utilities with similar projects and their
4 analysis has been used to support multi-billion-dollar investments in nine states:
5 Maryland, Illinois, Louisiana, Florida, Texas, Ohio, Indiana, Oklahoma, and
6 Missouri. They maintain a proprietary database of asset failure curves which were
7 reviewed and approved by the Company's engineering subject matter experts and
8 were applied to DTE Electric's actual asset age profiles.

9
10 Rebuttal Issue 14: AG-MN Witness Stephens's concerns with the value placed on
11 truck rolls in the Company's PTMM BCA Model.

12 **Q39. What concerns does AG-MN Witness Stephens express regarding the value**
13 **placed on truck rolls in the Company's PTMM BCA Model?**

14 A39. AG-MN Witness Stephens states on page 29, lines 14-17 and page 30, lines 1-7,
15 "... the PTMM benefit cost analysis overestimates the benefits from avoided costs
16 by assuming that every truck roll avoided (for example, to respond to a pole top
17 equipment failure or a related service interruption) reduces DTE's costs by \$2,000.
18 This appears to be a fully-loaded cost, typically estimated by dividing annual field
19 crew costs, related service center costs (such as the cost of supervisors), vehicle
20 costs, and all allocated corporate general and administrative costs (such as from
21 human resources, accounting, and regulatory services departments) by a count of
22 truck rolls completed in a year. Many if not most of these costs are fixed. What is
23 needed for this estimate is the marginal cost avoided by a truck roll, which is
24 typically gasoline (for the truck) and perhaps some overtime costs. There is no

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1 chance whatsoever that the average marginal cost avoided by a truck roll is anything
2 remotely close to \$2,000.”

3

4 **Q40. Do you agree with AG-MN Witness Stephens’s assertions that the PTMM**
5 **BCA model overstates the cost of truck rolls?**

6 A40. No. AG-MN Witness Stephens argues that only gasoline and overtime should be
7 included for truck rolls in the PTMM BCA as all other costs are fixed and fully
8 loaded. This argument is flawed because it ignores the opportunity costs associated
9 with the inefficiency of dispatching field personnel to address customer outages
10 and wire downs due to emergent pole and pole-top equipment failures, rather than
11 performing programmatic capital improvements where work is performed on the
12 entire circuit and thus a more efficient use of field personnel time.

13

14 It is important to note that the total calculated benefits derived within the PTMM
15 BCA Model from emergent reactive reductions across all circuits is \$1,734,845,577
16 whereas the total calculated benefits from customer outage reductions is
17 \$8,240,507,074 for the years 2024-2063. This means that 17% of the total modeled
18 benefits come from emergent reactive event reductions. It is also important to
19 further note that truck rolls are the smallest portion of modeled emergent reactive
20 reductions.

21

22 Emergent reactive reductions modeled values are:

- 23 • Pole Replacements: \$15,000
- 24 • Pole-top Replacements: \$8,500
- 25 • Truck Rolls: \$2,000

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2

The Company tested the sensitivity of truck roll cost assumptions and their impact on the PTMM benefit-cost ratios. The system-wide (all circuits) average benefit-cost ratios (BCR) calculated with three different values of truck roll estimates tested are shown below:

6

7

- \$2,000 truck roll assumption: 3.76 BCR

8

- \$350 truck roll assumption: 3.71 BCR

9

- \$0 truck roll assumption: 3.70 BCR

10

11

These results show that the PTMM BCA Model is not sensitive to the value placed on truck rolls (e.g., whether they be set to \$0, \$350, or \$2,000).

13

14

Rebuttal Issue 15: AG-MN Witness Stephens's concerns that the PTMM BCA understates customer costs.

15

16

Q41. What concerns does AG-MN Witness Stephens express that customer costs may be understated in the PTMM BCA?

17

18

A41. AG-Witness Stephens states on page 30, lines 8-17, "... the PTMM BCA also understates customer costs. The costs in the model represent the present value of the costs the Company must pay. It does not include the costs customers must pay on top of DTE capital costs, including DTE's interest expense, a rate of return for shareholders, property taxes DTE must pay to local governments, or state and federal income taxes on the profits DTE earns on PTMM capital spending. Between overstated benefits and understated costs, the Company's representation that the

19

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21

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1 upgraded poletop construction standards, or the PTMM program based on those
2 standards, deliver benefits in excess of costs rests on a weak foundation.”

3

4 **Q42. Do you agree with AG-MN Witness Stephens that the PTMM BCA Model is**
5 **faulty because it does not account for interest expense, return to shareholders,**
6 **and income taxes?**

7 A42. No. The PTMM BCA Model uses as a discount rate of 6.92%, which is the
8 Company’s pre-tax weighted-average cost of capital. This weighted-average cost
9 of capital incorporates the cost of debt, the cost of equity, and the respective weights
10 of each type of capital (e.g., equity, long-term debt, and deferred taxes). The stream
11 of benefits enabled by the investment is discounted by this 6.92% rate. The benefits
12 are then compared against the capital investment required. To develop an annual
13 revenue requirement model for this required investment, one would apply the pre-
14 tax cost of capital rate (6.92%) against the investment. However, to compare this
15 stream of cash flows against that of the benefits, one would then discount the stream
16 by that same 6.92% rate, effectively resulting in the initial capital investment
17 amount. Therefore, the model’s current methodology is a valid comparison
18 between the two options.

19

20 **Q43. Do you agree with AG-MN Witness Stephens that the PTMM BCA modeled**
21 **results rest on a “weak foundation” because it does not take property taxes**
22 **into account?**

23 A43. No. While it is true that there are property tax implications for replacing poles and
24 pole-top equipment within the PTMM Program, the same is true for poles and pole-
25 top equipment replaced upon failure (Capital Emergent Replacements Storm and

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1 Non-Storm). All equipment replacements the Company performs has an impact on
2 property taxes wherein the taxable value of assets previously installed is removed
3 from the tax base and the value of the new assets installed is added to the tax base
4 and used to calculate property taxes going forward.

5
6 Precisely modeling the property tax implications requires extremely specific
7 assumptions which consider 1) the value, quantity, and timing of assets that are
8 being replaced and thus no longer subject to property tax, 2) the value, quantity,
9 and timing of assets being installed and thus subject to property tax going forward,
10 and 3) a comparison of the changes between 1 and 2 which demonstrate the
11 incremental property tax incurred for any given year.

12
13 In evaluating the model's sensitivity to property tax impacts, it is helpful to consider
14 that the PTMM BCA Model (Exhibit A-51, Schedule PP10) spans 2024-2063 and
15 its calculated outputs ("Summary" tab columns D, H, and I) are as follows:

- 16
- 17 • Total PTMM Investment Required (if all circuits were completed):
18 \$2,617,033,948
 - 19 • Total Emergent Reactive Benefit (capital replacements avoided during
20 Storm and Non-Storm by performing PTMM): \$1,734,845,477
 - 21 • Total Customer Outage Avoidance Benefit (values derived from LBNL ICE
22 Calculator methodology): \$8,240,507,074

23
24 If the Company did not perform PTMM, it would still incur incremental property
25 taxes associated with the difference between the \$1,734,845,477 in Emergent

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1 Reactive capital replacements minus the taxable value of the assets that were
2 replaced and therefore removed from tax base. Performing PTMM on all circuits
3 would require an investment of \$2,617,033,948 and the Company would incur
4 additional property taxes associated with this value minus the taxable value of the
5 assets that were replaced and therefore removed from tax base. Please note that the
6 modeled customer benefits are orders of magnitude higher than both the
7 expenditures required for Emergent Replacements and those required to perform
8 PTMM.

9
10 While there is an incremental property tax associated with performing PTMM, it is
11 not as large as AG-MN Witness Stephens seems to imply, and is only applicable to
12 the PTMM investment that is above the amount that would be incurred for
13 Emergent Capital Replacements.

14
15 I have provided an example of property tax impacts from the capital replacements
16 in Table 6. Please note that the hypothetical example provided is \$1,000,000 of
17 investment and it results in \$27,000 of taxable value in year one and diminishes to
18 \$14,000 of taxable value in year fifteen where it remains until the asset is retired
19 and replaced. In reality, the Company's incremental property tax burden would be
20 less than these totals, because the taxable value of the assets that were replaced
21 would be removed, and the incremental property tax would be the difference
22 between the new property taxes and the property taxes paid on the assets that were
23 replaced. This example holds true for both PTMM Program work and Emergent
24 Capital Replacements.

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Table 6 – Property Taxes on Capital Investments (Example)

\$ thousands	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10	Yr 11	Yr 12	Yr 13	Yr 14	Yr 15
Capital Invested	\$ 1,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
STC	0.96	0.93	0.90	0.86	0.82	0.78	0.74	0.70	0.67	0.64	0.61	0.58	0.55	0.52	0.50
True Cash Value	\$ 960	\$ 930	\$ 900	\$ 860	\$ 820	\$ 780	\$ 740	\$ 700	\$ 670	\$ 640	\$ 610	\$ 580	\$ 550	\$ 520	\$ 500
Tax Value Adjustment	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Taxable Value	\$ 480	\$ 465	\$ 450	\$ 430	\$ 410	\$ 390	\$ 370	\$ 350	\$ 335	\$ 320	\$ 305	\$ 290	\$ 275	\$ 260	\$ 250
Property Tax Millage	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00
Property Taxes	\$ 27	\$ 26	\$ 25	\$ 24	\$ 23	\$ 22	\$ 21	\$ 20	\$ 19	\$ 18	\$ 17	\$ 16	\$ 15	\$ 15	\$ 14

2

3 **Q44. Does AG-MN Witness Stephens express similar concerns with the Company's**
4 **Strategic Undergrounding BCA?**

5 A44. No. AG-MN Witness Stephens did not express concerns with the Strategic
6 Underground BCA, which utilized the same consultant and approach, but used the
7 modeled outputs to support his recommendation for disallowance.

8

9 Rebuttal Issue 16: AG-MN Witness Stephens's concerns that the PTMM BCA
10 Whitepaper only refers to 2,242 modeled circuits and it is not clear where benefit-
11 cost ratios are provided.

12 **Q45. What concerns does AG-MN Witness Stephens express with regards to the**
13 **quantity of circuits in the PTMM BCA Model?**

14 A45. AG-MN Witness Stephens states on page 30, lines 19-20 and page 31, lines 1-4,
15 "... the report states that of 2,242 circuits modeled, benefits exceeded costs on 95%
16 of these. However, DTE maintains 3,273 distribution circuits, and the Company's
17 confidential workpaper indicates 2,242 circuits is only about 60% of the
18 Company's total circuits. The report does not indicate what criteria the consultant
19 applied to select a subset of the Company's circuits for its stated conclusion, or why
20 they selected only a portion of circuits to summarize in its whitepaper."

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2 **Q46. Does the Company's PTMM BCA Model only include 2,242 circuits?**

3 A46. No. While the PTMM BCA whitepaper does have a reference to 2,242 modeled
4 circuits, the "Summary" tab of the PTMM BCA Model (Exhibit A-51, Schedule
5 PP10) that the Company shared with AG-MN Witness Stephens contains a total of
6 3,844 circuits including subtransmission circuits.

7

8 **Q47. Does the PTMM BCA Model clearly show the benefit-cost ratios for all**
9 **circuits?**

10 A47. Yes. The Company provided the PTMM BCA model in its entirety in discovery
11 response NDA U-21534 MNSCDE-3.10b-01 PTMM BCA Model.xlsm (Exhibit A-
12 51, Schedule PP10).

13

14 All circuits are shown on the "Summary" tab and the benefit-cost ratio is provided
15 for each circuit in column K titled "BCA (Emergent Reactive and Customer Outage
16 Benefit)." The "Summary" tab includes 3,844 circuits in total and 2,360 of these
17 circuits have a benefit-cost ratio at or above one.

18

19 The Company informed MNSC in discovery response U-21534 MNSCDE-15.24
20 (Exhibit A-51, Schedule PP12) that this was the field that demonstrated the benefit-
21 cost ratio for circuits and was used to determine whether a circuit was suitable for
22 selection within the PTMM Program.

23

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1 Rebuttal Issue 17: AG-MN Witness Stephens's recommendation to order the
2 Company to perform a new analysis comparing PTM to PTMM.

3 **Q48. What is AG-MN Witness Stephens's recommendation for additional PTMM**
4 **analysis beyond the PTMM BCA already performed?**

5 A48. AG-MN Stephens says on page 31, lines 13-19, "I recommend the Commission
6 order DTE to present an assessment of the reliability difference between PTM
7 circuits and PTMM circuits using historical data in a way that prevents the
8 comingling of tree trimming benefits, and to calculate the monetary value of the
9 reliability improvements relative to the incremental costs of the new pole top
10 construction and inspection standards. This information is necessary for DTE to
11 support its proposed increasing level of capital spending in the PTMM program."

12

13 **Q49. Do you agree with AG-MN Witness Stephens's recommendation to perform**
14 **additional analysis comparing PTM to PTMM?**

15 A49. No, I do not. The Company has shown that its inspection and construction standard
16 changes are supported by benchmarking and industry research. The Company has
17 also performed a benefit-cost analysis that shows the PTMM program (with new
18 standards) is cost beneficial to customers. There is no need for additional analysis
19 to support the program investments.

20

21 Rebuttal Issue 18: AG-MN Witness Stephens's recommendation to cap PTMM
22 Program investment levels at \$63.45 million for 2025.

23 **Q50. What does AG-MN Witness Stephens propose concerning PTMM Program**
24 **investments in 2025?**

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1 A50. AG-MN Witness Stephens states on page 32, lines 1-5, “Regarding test year
2 spending, DTE has not supported the request to increase spending in the PTMM
3 beyond what was approved in U-21297, which was \$63.45 million. The
4 Commission should cap test year spending accordingly. This will ensure customers
5 will not be deprived of benefits in the event the new construction standards prove
6 to be cost-effective.”

7
8 **Q51. Do you agree with AG-MN Witness Stephens’s assertion that the Company**
9 **has not supported its request to increase PTMM investments?**

10 A51. No. The Company has provided evidence that the inspection and construction
11 standard changes were in-line with benchmarking and industry research performed
12 and has supported investment increases with a benefit-cost analysis model.

13
14 **Q52. Should the Commission adopt AG-MN Witness Stephens’s recommendation**
15 **for capping 2025 PTMM investments at \$63.45 million?**

16 A52. No. The Commission should reject AG-MN Witness Stephens’s recommended cap
17 of PTMM investments.

18

19 **Breaker Replacement Program**

20 Rebuttal Issue 19: AG-MN Witness Stephens’s assessment and recommendation for
21 the Breaker Replacement Program

22 **Q53. What is AG-MN Witness Stephens’s assessment and recommendation**
23 **concerning the Breaker Replacement Program?**

24 A53. AG-MN Witness Stephens states that he found the program did not deliver benefits
25 in excess of its costs to customers in Case No. U-21297, states that the Company

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1 has not performed a benefit-cost analysis (BCA) for the program, and
2 recommended the Commission reject the proposed IRM for 2026 and 2027 on
3 pages 43 through 45 of his testimony.

4

5 **Q54. What was the Commission's position in Case No. U-21297 regarding the**
6 **Breaker Replacement Program investments?**

7 A54. The Commission stated on page 101 in its order dated December 1, 2023, "The
8 Commission finds that the replacement of obsolete circuit breakers is the type of
9 work, like the removal of arc wire, that is necessary and lends itself to few
10 alternatives. ...The company provided evidence that 60% of breakers in the
11 distribution and subtransmission systems (including substation reclosers) are
12 beyond their life expectancy. DTE Electric provided the criteria used for selecting
13 which breakers to replace and indicated that it plans to replace 35 breakers in 2023
14 and 36 in 2024."

15

16 Additionally, the Commission approved the inclusion of the Breaker Replacement
17 Program in the Company's Distribution IRM for the years 2024 and 2025 in Case
18 No. U-21297.

19

20 **Q55. AG-MN Witness Stephens points out that a BCA has not been performed for**
21 **the Breaker Replacement Program, how would you respond?**

22 A55. As described by Company Witness Kryscynski in rebuttal testimony, the Company
23 has performed two BCAs (PTMM and Strategic Undergrounding) and is moving to
24 perform more BCAs as part of its overall strategy to support its investments.

25

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1 It is important to note that some of the prerequisite infrastructure investments (such
2 as breaker, URD cable, and system cable replacement), are so foundational and
3 indispensable for the continuity of electric service and the consequences of failure
4 so great (with large scale prolonged outages and the possibly of extensive system
5 damage beyond the breaker itself), that a run-to-failure approach is simply not
6 acceptable.

7

8 **Q56. Can you put the Breaker Replacement Program in context in terms of its scope**
9 **and relative size?**

10 A56. Yes. The Breaker Replacement Program is targeted at breakers that are obsolete
11 and/or have known issues which can cause failures. The Company has invested, on
12 average, approximately \$14.1 million and replaced approximately 35 breakers per
13 year over the span 2020-2023 (Table 7).

14

15 **Table 7 – Breaker Replacement Program (2020-2023)**

Breaker Replacement Program	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2020-2023 Avg
Capital Invested (\$ thousands)	\$10,931	\$17,635	\$14,415	\$13,590	\$14,143
Breakers Replaced	37	39	34	29	35

16

17 As stated in my testimony on page 101, line 9, the Company has approximately
18 6,000 breakers on its system. This average annual replacement of 35 breakers per

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1 year from 2020-2023 represents 0.6% of the Company's breakers and a 171-year
2 replacement cycle (Table 8) and the combined four-year total of 139 breakers miles
3 is 2.3%⁷ of total breakers.
4

5 **Table 8 – Breaker Replacement Program Cycle (2020-2023 Average)**

Total Breakers	2020-2023 Annual Avg. Breaker Replacements	Annual Avg. % Replaced (35 / 6,000)	Replacement Cycle (6,000 / 35)
6,000	35	0.58%	171 years

6 Please note that the Company's current breaker replacement cycle of 171 years far
7 exceeds expected useful life of breakers (30-40 years) and the Company will need
8 to increase the rate of replacement in the near future.
9

10 **Q57. Should the Commission adopt AG-MN Witness Stephens's disallowance of**
11 **capital investment for the Breaker Replacement program in the 2026 and 2027**
12 **IRM?**

13 A57. No. As I have described above, these investments are reasonable and prudent.
14 Further, the URD Replacement program meets the screening criteria used by the
15 Company to identify investment programs that are good candidates for IRM
16 treatment. Please see Company Witness Foley's testimony for additional rebuttal
17 on this topic.
18

⁷ 2020-2023 total breakers replaced divided by total breakers (139 / 6,000 = 2.3%)

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1 **Underground Residential Distribution (URD) Replacement Program**

2 **Rebuttal Issue 20: AG-MN Witness Stephens's assessment of the URD Replacement**
3 **Program.**

4 **Q58. What is AG-MN Witness Stephens's assessment and recommendation**
5 **concerning the URD Replacement Program?**

6 A58. AG-MN Witness Stephens states that he found the program did not deliver benefits
7 in excess of the costs to customers in Case No. U-21297, states that the Company
8 has not performed a benefit-cost analysis (BCA) for the program, and
9 recommended the Commission reject the proposed IRM for 2026 and 2027 on
10 pages 43 through 45 of his testimony.

11

12 **Q59. What was the Commission's position in Case No. U-21297 regarding the URD**
13 **Replacement Program investments?**

14 A59. The Commission stated on page 99 of its order dated December 1, 2023, "The
15 Commission recognizes that regular maintenance is necessary and that faulty cables
16 should be replaced, and DTE Electric provided evidence that multiple factors are
17 considered in determining where replacements are necessary including vintage,
18 number of failures, and number of affected customers, as well as safety
19 improvements."

20

21 Additionally, the Commission approved the inclusion of the URD Replacement
22 Program in the Company's Distribution IRM for the years 2024 and 2025 in Case
23 No. U-21297.

24

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1 **Q60. AG-MN Witness Stephens points out that a BCA has not been performed for**
2 **the URD Breaker Replacement Program, how would you respond?**

3 A60. As described by Company Witness Kryscynski in rebuttal testimony, the Company
4 has performed two BCAs (PTMM and Strategic Undergrounding) and is moving to
5 perform more BCAs as part of its overall strategy to support its investments.

6

7 It is important to note that some of the prerequisite infrastructure investments (such
8 as breaker, URD cable, and system cable replacement), are so foundational and
9 indispensable for the continuity of electric service and the consequences of failure
10 so great (with large scale prolonged outages and the possibly of extensive system
11 damage beyond the breaker itself), that a run-to-failure approach is simply not
12 acceptable.

13

14 **Q61. Can you put the URD Replacement Program in context in terms of its scope**
15 **and relative size?**

16 A61. Yes. The URD Replacement Program is targeted at URD feeders that have
17 experienced multiple failures and are known to contain URD cable that is near or
18 beyond expected useful life (40 years). The Company has invested an average of
19 \$6.3 million and replaced an average of 37 miles per year over the span 2020-2023
20 (Table 9).

21

Line
No.

1

Table 9 – URD Replacement Program (2020-2023)

URD Replacement Program	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2020-2023 Avg
Capital Invested (\$ thousands)	\$964	\$4,705	\$7,043	\$12,411	\$6,281
URD Cable Miles Replaced	3.6	24.5	44.7	75.3	37

2

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Table 10 – URD Replacement Program Cycle (2020-2023)

Total URD Cable Miles	2020-2023 Annual Avg. URD Cable Miles Replaced	Annual Avg. % Replaced (37 / 10,580)	Replacement Cycle (10,580 / 37)
10,580	37	0.35%	286 years

10

⁸ 2020-2023 total URD cable miles replaced divided by total URD cable miles (148.1 / 10,580 = 1.39%)

Line
No.

1 Please note that the Company's current URD cable replacement cycle of 286 years
2 far exceeds expected useful life of URD cable (40 years) and the Company will
3 need to increase the rate of replacement in the near future.

4

5 **Q62. Should the Commission adopt AG-MN Witness Stephens's disallowance of**
6 **capital investment for the URD Replacement program in the 2026 and 2027**
7 **IRM?**

8 A62. No. As I have described above these investments are reasonable and prudent.
9 Further, the URD Replacement program meets the screening criteria used by the
10 Company to identify investment programs that are good candidates for IRM
11 treatment. Please see Company Witness Foley's testimony for additional rebuttal
12 on this topic.

13

14 **General Rebuttal Points**

15 **Q63. Have any intervenors requested that the MPSC make additional disallowances**
16 **or direct the Company to undertake any specific activities related to**
17 **distribution infrastructure or processes?**

18 A63. Yes, intervenors have suggested a collection of conceptual proposals listed in Table
19 11 below for the Company to undertake. However, as a group these suggested
20 directives are undefined and largely lack the detail requisite to be thoroughly
21 considered. The time, resources, costs, and other inputs necessary to begin these
22 tasks have neither been discussed nor even listed; the resultant values have not been
23 calculated nor considered; alternatives have not been identified nor compared. In
24 an attempt at brevity, the Company is not rebutting all the unsupported and

Line
No.

1 misguided suggestions individually. All of these requested directives should be
2 denied.

3 **Table 11 – General Rebuttal Issues**

Witness	Rebuttal Point	Rebuttal
ABATE – York	Regarding distribution capital strategic replacements, on page 31, lines 6-11 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. ”	Page 70 of Company Witness Uzenski’s direct testimony, lines 19-25 (Q&A 135) states that for capital expenditures on projects that will not be in service during the projected test period do not have a current revenue requirement. Additionally, the Commission found Witness York’s similar proposed adjustments in case No. U-21297 unpersuasive by stating 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.” ⁹ The Company recommends the Commission disregard Witness York’s recommendation in the instant case.

4

5

6 **Q64. Does this conclude your testimony?**

7 A64. Yes.

⁹ Page 84 of Commission Order issued in Case No. U-21297 and dated December 1, 2023

1 JUDGE WALLACE: And then we'll deal with
2 the exhibits at the end of cross. But based on the
3 motion the other day, one of the rebuttal exhibits, you
4 guys will be objecting to?

5 MS. ANDREWS: Well, based on the ruling
6 in that part of the motion to strike where your Honor
7 didn't strike the testimony, I would probably not. It's
8 a good idea. I hadn't thought to maintain my objection
9 to the exhibit since the, you know, it's supporting
10 testimony that's in the record; my objection to the
11 exhibit was based on the testimony that it was tied to.

12 JUDGE WALLACE: Well, and you still have
13 the opportunity to renew the motion in your briefing.
14 O.K. So that's Exhibit A-12 Schedule B5.4, A-12 Schedule
15 B5.4.8; A-23 Schedules M5, M9, M10, M12, and M 13, and
16 then Exhibit, rebuttal Exhibit A-51 Schedule PP1 through
17 PP10, and then PP12 through PP14. Again, we will admit
18 those at the close of cross.

19 All right. Ms. Andrews, please go ahead.

20 MS. ANDREWS: Thank you.

21 CROSS-EXAMINATION

22 BY MS. ANDREWS:

23 Q Good afternoon, Ms. Elliott Andahazy. We have met
24 before, I believe there was a storm last time we did
25 cross-examination, I don't know if you remember that.

1 A I do recall.

2 Q So I would just like to ask, I don't think we'll take
3 four hours that we've got reserved today, but I wanted to
4 ask you a few questions about the Company's pole top
5 moderniz -- maintenance and modernization, PTMM program,
6 which is a program that you are the witness supporting
7 the investment plan for; is that accurate?

8 A Yes.

9 Q All right. I'd first like to understand a little bit
10 more about the inspections component of the PTMM program.
11 As I understand it from your Exhibit A-12 B5.4.8, the
12 Company has broken down the PTMM program into its
13 component parts, inspection and testing, reinforcement,
14 line miles modernized, and then pole replacements; do you
15 see that?

16 A I do.

17 Q So were you on yesterday for the cross-examination of
18 Mr. Kryscynski?

19 A I heard portions of it, but not the whole thing.

20 Q O.K. There was a discussion in the context of the
21 Company's Global Prioritization Model, the GPM, related
22 to regulatory compliance and the issue as to the
23 Company's obligation to inspect poles. Can you elaborate
24 on what is the source of the Commission obligation or the
25 Company's, the Commission direction or the Company's

1 obligation for pole inspection?

2 A Sure. If you give me a moment, I'd like to make sure
3 that I just validate in my testimony that I'm using the
4 proper name of the document for which we are discussing.

5 Q And if you can refer me to the same page, it would be
6 efficient.

7 A I sure will. Give me one moment, please. I am not
8 finding the direct reference in my testimony as I'm
9 skimming through; if you give me another moment, please.

10 MS. JOHNSON-BACON: If it's acceptable, I
11 think I can speed this along.

12 MS. ANDREWS: Well, either you or I. I
13 was going to point her to Q48 on page 42; is that where
14 you were looking at?

15 MS. JOHNSON-BACON: Yes, I was going to
16 direct --

17 (Multiple speakers.)

18 COURT REPORTER: I'm sorry, you guys.
19 Wait. Stop, stop, stop one second. Before we go --

20 (Multiple speakers.)

21 COURT REPORTER: Wait a minute. Stop.
22 Let's start from the beginning because all of you can't
23 talk at the same time. Ms. Andrews.

24 MS. JOHNSON-BACON: Could you repeat the
25 question, please?

1 Q (By Ms. Andrews): What was the source of the Company's
2 obligation from the Commission with respect to its pole
3 inspection program?

4 A Thank you for repeating the question. So on November 20,
5 2009, the MPSC Staff published a Utility Pole Inspection
6 Program Investigation Staff Report, and in that report
7 the Staff recommended that we achieve a 10- to 12-year
8 pole inspection cycle frequency, which correlates to the
9 standard recommended by the USDA Rural Utility Service
10 for Michigan's Decay Zone.

11 Q And is it fair to say that at least since 2009, if not
12 before, the Company has been working towards the 10- to
13 12-year pole inspection standard, or guidance?

14 A I would say that in my direct testimony on page MEA-48,
15 we do have a figure that shows the number of inspections
16 for which the Company was attempting to meet that 10- to
17 12-year cycle as guided by the MPSC Staff Report.

18 Q You said page 48?

19 A Yes.

20 Q Are you looking at Table 10?

21 A I'm looking at Figure 13.

22 Q Oh, that's on page 49 of my testimony. That's
23 interesting, I think we had a -- O.K. That's fine.
24 Thank you for the clarification. Figure 13, the pole
25 inspections.

1 O.K. So what is the Company's current
2 pole inspection cycle, how close are you to -- what's
3 your inspection cycle at the moment?

4 A So as can you see in Figure 13, through the year 2022, we
5 were on that 10- to 12-year cycle, however, in 2023 and
6 as indicated in my direct testimony in this instant case
7 regarding inspections for 2023, we only inspected just
8 over 12,000, almost 13,000 poles, which, if you do the
9 math, puts us on a much larger pole inspection cycle.
10 I'd have to do the math, but I believe it's between a 70-
11 to 80-year for the inspection. We did that -- well, you
12 didn't ask me why.

13 Q Well, so I guess I'm trying to understand, I'm trying to
14 catch up with you. I see the number of poles inspected
15 per year, but I don't see whether it's a 10-year, a 10,
16 10 1/2, 11, 10.2. I see a number of, a number of poles
17 inspected, but it doesn't tell me in the scheme of the
18 Company's, the number of poles you have, what that
19 translates into in terms of the cycle length.

20 A I would have to validate the number, however, it is my
21 understanding that we have close to a million poles that
22 are on our system that we would have in that PTMM
23 program.

24 Q So let's go back to your direct testimony, page 3 -- oh,
25 well, Q42, it's on page 34 of my version. It says: The

1 Company is aspiring to implement a PTMM program capable
2 of inspecting, and completing the required construction,
3 for poles on a 10-year cycle. Are you with me?

4 A Yes.

5 Q So the word aspiring there suggests to me that the
6 Company is not yet on a 10-year cycle; is that right?

7 A In 2023 and 2024, we are not currently on a 10-year cycle
8 for inspecting and completing construction for the PTMM
9 program.

10 Q So why were inspections so low in 2023?

11 A I believe that is also in my direct testimony. In
12 summary, because we recognized that while we had been
13 inspecting poles in previous years, based on the
14 investment levels for which we had been previously
15 approved, we were not completing all of the associated
16 construction that was required based on the pole
17 condemnation and the pole top common failure rates that
18 we were seeing, and we did not want to continue to
19 increase the backlog of necessary construction.

20 Q O.K. Thank you. I want to talk a little more about the
21 pole specifi -- oh, let me ask a different question. How
22 close are you to the five-year cycle for pole tops, the
23 aspirational goal of five-year inspections for pole tops?

24 A Right now, when we inspect the poles, we inspect the pole
25 tops at the same time, so they are on the, currently on

1 the same cycle.

2 Q O.K. So I'd like to look at the -- well, talk for a
3 moment about your pole specification standard, which is
4 Exhibit A-23 Schedule M9.

5 A O.K.

6 Q It's my understanding that this is the version of the
7 pole, wood pole maintenance specification that was last
8 updated on December 7, 2021; is that correct?

9 A The date is blocked out on the version of this exhibit,
10 however, to my recollection, I believe that sounds about
11 correct on the date.

12 Q O.K. I -- sorry, I don't mean to talk over you. I am
13 interpreting the 12/7/21 at the very bottom of the cover
14 page and on each subsequent page as a date, but maybe
15 that's not correct.

16 A I would have to validate that.

17 Q O.K. So on the third page of the exhibit, there is a
18 change date and a summary of the various sections and
19 notes about what changes were made, and I assume these
20 are dates -- well, it says change date. So it looks like
21 the last date, the last change was made December 7, 2021,
22 right?

23 A On this document in the exhibit, yes, I would agree based
24 on this table on page 3.

25 Q And the change that happened in December 2021 was that

1 photos would be taken upon work completion, right?

2 A For the table, that is what is written under the notes
3 for that change.

4 Q Just in general, is it your understanding that this pole
5 specification was adopted in about 2019 and has been
6 amended as shown in the changed page 3?

7 A This is a -- the pole specification document, we have had
8 a pole specification document for inspections that we
9 have been using prior to 2019 that I believe we submitted
10 through one of the discovery questions; I can validate if
11 you would like. This is the document that beginning in,
12 yes, July -- or excuse me -- it looks like July of 2019,
13 which is the first change date that is listed on page 3
14 of this document is when this current format took shape.

15 Q And so you also produced in discovery and also as an
16 exhibit, a rebuttal Exhibit A-51 Schedule PP13, some
17 background information related to the Company's updates
18 to its pole inspection, pole top and pole inspection
19 program. Is that a fair summary? I'm sorry, not pole
20 top. Pole and pole inspection.

21 A The -- can you just rephrase that one more time, please?

22 Q Exhibit A-51 PP13 provides some documentation that was
23 also provided in discovery regarding the workup to some
24 pole inspection and pole specification modifications?

25 A In Exhibit PP13 we do provide some historical, some

1 information regarding the updates that were made to the
2 inspection and construction standards with some
3 associated attachments of those prior documents when
4 those updates were made, yes.

5 Q Looks like the Company undertook a pilot in 2018 that led
6 to updates in 2019, I saw that in here. I'm looking at
7 page 15 of 15, 2018 wood pole inspection process pilot
8 and then the wood, 2019 wood pole inspection process.

9 MS. JOHNSON-BACON: Sorry, T.J., what's
10 the question?

11 Q (By Ms. Andrews): I'm just confirming that there was a
12 pilot that then led to a new process or a revamped
13 process or modifications to the process for wood pole
14 inspections.

15 A Which document are you looking at, please?

16 Q That same PP13, the last page, the header of the
17 presentation, Pilot 2018 Pilot 2019 Process.

18 A The header does state there was a 2018 wood pole process
19 pilot and 2019 wood pole inspection process.

20 Q And this preceded the Company's -- these documents
21 preceded the Company's adoption of the wood pole
22 specification in Exhibit M9, Schedule M9, correct?

23 A I'm just looking for my M9 exhibit. Can you please
24 restate the question for me now that I've found it?

25 Q The pilot and analysis, the presentation and analysis in
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1 Schedule PP13 preceded and informed the Company's
2 adoption of the wood pole specification, maintenance
3 specification in Schedule M9?

4 A Based on the dates on the documents, it does appear as
5 though the document in PP13, specifically the slides
6 beginning on page 12 through 15 of PP13, did precede the
7 updates that were made in the pole specification --
8 excuse me -- wood pole maintenance specification document
9 which is in Schedule M9.

10 Q So turning to pole top specifications, the pole top
11 specification, which is in A-23 M10.

12 A O.K.

13 Q This document does not have a date, cover page, or change
14 sheet, looks like it's missing page 1, it starts with
15 page 2?

16 A In looking at the exhibit, it does not appear to have a
17 cover page or a change sheet.

18 Q Do you know when the pole top maintenance specification
19 was adopted by the Company, this pole top maintenance
20 specification?

21 A The Company has had a pole top maintenance specification
22 for the duration of the PTMM program. Without veri -- I
23 would have to verify as to when this particular document
24 was last updated, but it is, it is updated as required
25 for the equipment.

1 Q What is -- you indicated for the duration of the PTMM
2 program. What does the Company consider the duration of
3 the PTMM program?

4 A Let me rephrase. It is my understanding that we have had
5 a pole top equipment specification document to use as a
6 guideline for rules of engagement to inspect pole tops
7 for the duration of the PTMM program. I personally am
8 not familiar with exactly when the PTM program had began.

9 Q So the PTM program preceded the PTMM program, right?

10 A Yes.

11 Q And does the Company consider the second M, the PTMM
12 program to have started around 2019? When is the era of
13 PTMM?

14 A Yes. So it was formally, the program was formally
15 changed from PTM to PTMM, which includes the
16 modernization, in 2019, and that was to reflect two
17 items: (1) the changes in the wood pole inspection
18 process, and (2) to also identify the compilation or
19 evolution of the specification changes that had occurred
20 to the pole top equipment in the years preceding that
21 time.

22 Q O.K. So let's look at those specifications for pole top
23 equipment. Let's look in the -- do you have access to
24 the SharePoint?

25 A I believe I do.

1 Q Let's look at MEC-75.

2 A O.K.

3 Q MEC-75 I will represent to you is an excerpt from a
4 transcript in Case No. 20162, DTE rate case I believe
5 that was filed in 2018, it's a hearing in 2018, and it's
6 an excerpt from the testimony of Mr. Bruzzano. Do you
7 know who Mr. Bruzzano is, Marco Bruzzano?

8 A Yes.

9 Q Who is Mr. Bruzzano?

10 A I do not recall his exact title. He is currently a vice
11 president or senior vice president here at the Company.

12 Q O.K. And it appears that in 2018, Mr. Bruzzano was
13 responsible for doing what you're doing now, supporting
14 the Company's PT, at that time PTM program. Does that
15 sound right to you, do you have any reason to object to
16 my characterization?

17 A This appears to be Mr. Bruzzano being sworn in for
18 cross-exam, and as I scan through the document, there is,
19 there appears to be his direct testimony, which includes
20 pole and pole top hardware, pole top maintenance, yes.

21 Q O.K. So if we turn to the exhibit page 17, Mr. Bruzzano
22 is asked: Does the Company replace failed equipment with
23 identical equipment for pole and pole top hardware
24 programs; and he replies no. He indicates that: When
25 the Company replaces items, these items, it uses

1 equipment that complies with current standards. And then
2 he goes on to say, starting on line 5: DTE Electric
3 replaces wood crossarms with fiberglass crossarms,
4 porcelain crossouts with polymer crossouts, and porcelain
5 insulators with polymer clamp-top insulators. Do you see
6 that?

7 A I do see that.

8 Q Would you agree that that's consistent with the Company's
9 current approach to, in the PTMM program in terms of its
10 pole top replacements and its replace -- its approach to
11 replacements for pole top equipment?

12 A Based on what I'm reading here and my understanding of
13 our construction standards, without validating the actual
14 standards themselves, yes, this is consistent with
15 replacing, with what we do today with crossarms,
16 porcelain cutouts, and porcelain insulators.

17 Q So it's fair to conclude that since at least 2018, the
18 Company replaces when these three pieces of equipment,
19 crossarms, porcelain cutouts, and porcelain insulators,
20 when they are replaced, they have been following the same
21 replacement approach since at least 2018?

22 A Those standards were updated prior, it appears as though
23 prior to Mr. Bruzzano's testimony, and were updated prior
24 to the renaming of the program, as I stated earlier,
25 which was really to summarize the two main changes; it

1 was the compilation of all of these updated construction
2 standards as one and the updated wood pole specification
3 inspection process -- or requirement. Excuse me.

4 Q So let's look at the pole top specification, Exhibit A-23
5 Schedule 10, in a little more detail.

6 A O.K.

7 Q I understand as it applies to cutouts are covered on page
8 5.

9 A That is the fifth page in the exhibit, I agree.

10 Q So, and I would also refer you -- well, I'm reluctant to
11 do so given that you've got such big binders. In your
12 testimony on page 35, you say: Pole-top equipment which
13 fails inspection is replaced. Examples include, and you
14 say: Damaged/defective porcelain cutouts are replaced
15 with polymer cutouts. We're going to sort of cross-
16 reference the specification to your testimony.

17 A You're referring to line 18, is that what you said?

18 Q That's what it is in my testimony, I mean in my version.

19 A Damaged/defective porcelain cutouts are replaced with
20 polymer cutouts.

21 Q O.K. So according to the specification, all porcelain
22 cutouts are replaced, correct?

23 A Looking on the fifth page of Exhibit M10, which is the
24 pole top maintenance specification, it does read all
25 porcelain cutouts must be replaced.

1 Q So it doesn't matter whether the porcelain cutout is
2 damaged or defective, it's replaced either way?

3 A By definition, the porcelain cutouts are considered to be
4 defective equipment.

5 Q O.K. And then with respect to -- I'm looking at
6 Mr. Bruzzano's testimony, crossarms, DTE replaces wood
7 crossarms with fiber crossarms. That is only if they are
8 defective, correct? I'm looking at -- sorry -- page 13
9 of the specification I believe, just to --

10 A That is my understanding, and per that 13th page, it
11 does give examples of when they must be replaced,
12 specific examples, it does not say all.

13 Q Right. Right. So those are based on a visual inspection
14 of the equipment, correct?

15 A That is correct.

16 Q All right. So then let's look at porcelain insulators,
17 porcelain insulators are page 16 of the specification.

18 A O.K., I'm there.

19 Q It looks like -- the sort of formatting is odd -- but
20 porcelain post insulator to be replaced, looks like it
21 sort of runs from one sentence to the next. Are you
22 following along?

23 A Were you reading directly from the sheet just then?

24 Q I was. The line that's starting with F-neck insulator to
25 be reported if it is cracked, and then porcelain post, it

1 looks like it belongs on the next line; would you agree
2 with me, just --

3 A I do not know, I would have to ask --

4 Q O.K. Generally --

5 (Multiple speakers.)

6 COURT REPORTER: Ask? I'm sorry. Ask?

7 A I would have to ask our internal SMEs on the
8 specification.

9 Q (By Ms. Andrews): Is it your understanding that all
10 porcelain insulators are replaced with polymer
11 insulators?

12 A No. It is only my understanding that they are replaced
13 if they are found to be defective as defined in the
14 specification.

15 Q So what does the specification say about porcelain post
16 insulators?

17 A Report if cracked. Oh, I see what you're saying now. I
18 would have to validate that with the SMEs to understand
19 if that post, if the word post on the third line down is
20 supposed to be the beginning word on the fourth line,
21 which currently says insulator to be replaced.

22 Q Right. Looks like there's four different types of
23 insulators; disk, F-neck, porcelain post, and polymer
24 post. Subject to check, your understanding is -- I'm
25 trying to interpret your direct testimony -- defective/

1 damaged porcelain insulators are replaced with polymer
2 insulators. The question is whether it is all porcelain
3 posts are to be replaced or only porcelain posts that are
4 defective are to be replaced?

5 A I would need to validate with the SME responsible for
6 this specification to confirm that specifically for what
7 you are calling the post insulator.

8 Q I think it's a porcelain post insulator as opposed to a
9 polymer post insulator, but I'm trying to just interpret
10 a document that I'm not as familiar with. So my question
11 for you with respect to pole top, the pole top
12 maintenance specification, this standard, this
13 specification has been around since at least 2018; is
14 that correct?

15 A I would have to validate. That is my understanding that
16 there has been a version of the pole top maintenance
17 specification around since then, yes.

18 MS. ANDREWS: O.K. Your Honor, I'd move
19 for the admission of Exhibit MEC-75.

20 MS. JOHNSON-BACON: No objection.

21 MS. ANDREWS: Thank you.

22 Q (By Ms. Andrews): I'd like to --

23 JUDGE WALLACE: Hearing no objection,
24 Exhibit MEC-75 is admitted.

25 MS. ANDREWS: Sorry, your Honor. Didn't
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1 mean to --

2 JUDGE WALLACE: It's O.K.

3 MS. ANDREWS: Cut that out.

4 Q (By Ms. Andrews): So let's look at page 44 of your
5 direct testimony, at least in my testimony, my version,
6 question and answer 53 address recent changes to the
7 Company's PTMM program. Are you with me?

8 A I am here, yes.

9 Q And basically the first paragraph in my lines 12 through
10 22 describe the inspection and pole, and pole top
11 specifications that we've just talked about.

12 A Are you asking me a question?

13 Q I'm just orienting. Is that generally correct, the 2018
14 and '19 benchmarking that led to changes to the program
15 from PTM to PTMM?

16 A That is one of the items that I see written beginning on
17 line 13 describing, or responding to the question that
18 was asked about the recent changes we have made to the
19 program in recent years.

20 Q O.K. So the first set of changes took place in the early
21 years of the transition from the PTM to the PTMM program
22 around 2019 I think we established earlier?

23 A Yes.

24 Q The second set of improvements that you describe relate
25 to the joint use inspections. Can -- so as I understand

1 it from your testimony, a joint use inspection was when
2 an inspector looked at both pole tops and
3 telecommunication equipment and clearances; is that
4 correct?

5 A Yes. It's discussed a little bit more on one of the
6 following pages in my direct testimony. In summary, a
7 joint use inspection was when an inspector was going out
8 to evaluate equipment that is on DTE Energy poles that is
9 owned by non-DTE sources, such as your cable, the cable
10 lines that are on there, and we are, we go out to
11 evaluate and inspect the joint use equipment on those
12 poles. At the same time, we were also doing, we were
13 utilizing those inspections for the pole and pole top
14 maintenance as well. Those same inspectors. Excuse me.

15 Q And the Company has transitioned to no longer using joint
16 use inspectors and instead sort of focusing its
17 inspectors only on PTMM inspections; is that a fair
18 summary?

19 A For the purpose of the PTMM program, we are no longer
20 utilizing those joint use inspectors at inspections.

21 Q I'm sorry, I thought I heard another voice.

22 That change has been a couple of years in
23 place by now?

24 A Correct. Per Figure 13 on what I have as MEA page 48,
25 that is the pole inspection chart I referred to earlier

1 this afternoon, you can see in 2022 we were no longer
2 utilizing those inspections for the PTMM program.

3 Q O.K. And then the final improvements starting on page
4 9 -- sorry -- page 5, line 9, there were two categories,
5 inspection quality control and process improvements; do I
6 have that right?

7 A Yes, per page 45, lines 8 and 9, the third set of
8 improvements to the program can be summarized by
9 inspection quality control and process improvements that
10 were implemented in 2023.

11 Q So neither of the changes in 2023, the inspection quality
12 control or the process improvement, change the
13 specifications for the inspections, correct?

14 A In the context of what I'm describing in my direct
15 testimony here, these are not talking about changes to
16 either the wood pole inspection or the pole top equipment
17 specifications that are used during the inspection
18 process.

19 Q The inspection quality control involves training for
20 inspectors, tools, an audit of the inspection, sort of an
21 oversight over inspectors; is that fair understanding of
22 what the inspection quality control is?

23 A I believe you are summarizing lines, what is it, 11
24 through 16 of my direct testimony, and yes, that is an
25 overall summary of what is detailed there.

1 Q And the process improvements involve technology and other
2 tools to increase maybe one could say the efficiency of
3 the inspection process?

4 A Yes, as detailed in lines 16 and beyond on page 45, the
5 second portion of the process improvements do include
6 some technology and other process improvements that we
7 have made to the program.

8 Q Is it fair to say that since the initial enact -- switch
9 from PTM to PTMM in around 2019, the changes that have
10 been made to the PTMM program involve Company oversight
11 and process for managing the program as opposed to what
12 the inspectors and field work, what the people in the
13 field are doing to the poles and pole tops?

14 A I would have to validate and check to ensure from a
15 specification perspective that they have not changed as
16 we saw in the one that appears that there have been some
17 updates to the wood pole inspection specifically up
18 through 2021. In the context of what we're talking
19 about, though, the largest changes have been to, as you
20 have described, Company oversight and how we are
21 executing the work.

22 Q Is it fair to say that the changes in recent years,
23 especially in '22 and '23, have resulted in the
24 inspection of more poles and pole tops, though not
25 necessarily more miles of poles? I'm looking at the

1 Table 10, a few pages later, where you sort of outline
2 the history of unit work.

3 A Can you please repeat your question?

4 Q While circuit miles appear relatively consistent over the
5 evolution of the PTMM, the poles replaced and the pole
6 top locations replaced seem to have increased
7 substantially, particularly in the last two years. Fair
8 summary?

9 A Per Table 10, yes, the poles replaced and the pole top
10 locations for which we replaced pole top equipment have
11 increased, which speaks to an increase in the
12 condemnation rate.

13 Q The Company's investment plan, historic investment in
14 PTMM is also reflected in page, on page 48, Table 10, in
15 the bottom row. Do you see that?

16 A Yes, I do.

17 Q Would you agree that the Company's investment has also
18 increased substantially in 2022 and 2023?

19 A It has increased from mid 20s, mid 30s, in 2019, '20, and
20 '21, up into approximately 80 million in both '22 and '23
21 per the table, yes.

22 Q And the Company has plans to increase its investment in
23 the PTMM program in 2025 to \$121 million, if I understand
24 Exhibit A-12 B5.4, page 13, line 13, correctly?

25 MS. JOHNSON-BACON: Could you repeat
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1 that? I'm sorry, I didn't catch it.

2 MS. ANDREWS: Quite a test.

3 Q (By Ms. Andrews): According to Exhibit A-12 B5.4, page
4 13, line 13, the Company is proposing to increase the
5 PTMM investment in the test year 2025, or the test year
6 to 121 thousand -- million, and the calendar year, also
7 121 million?

8 A Yes, that is consistent with what is on page 13 of
9 Exhibit A-12 B5.4.

10 Q And the Company also proposes to include the PTMM program
11 in the IRM, that is, the extended IRM that is a proposal
12 in this case; is that correct?

13 A Yes. Per my testimony and referencing back to Company
14 Witness Foley, the proposal is to include the PTMM
15 program in the extended IRM proposal for 2026 and 2027.

16 Q And the proposed spending for the IRM is a further
17 increase over the 2025 proposed spending up to
18 150 million in 2026, correct?

19 A That is my understanding.

20 Q And then there's a further increase in 2027 to \$200
21 million; is that right?

22 A I would have to validate the document with that, for
23 2027's number.

24 Q A-20 -- A-33 X1.

25 A I don't believe I have that in front of me.

1 Q Oh. Subject to check?

2 A Subject to check.

3 Q All right. The Company maintains the outage management
4 system. Is that I believe is a system for maintaining
5 information on each outage that the Company -- that the
6 system experiences; is that fair summary?

7 A The Company does have an outage management system, also
8 called our OMS, that does maintain data on the emergent
9 trouble events that are reported.

10 Q And that system maintains information about location,
11 cause, weather, duration, and other information about
12 each outage, correct?

13 A Subject to check the specific information that's in the
14 database, that sounds about correct.

15 Q In your direct testimony with respect to the hardening
16 program, you support a couple of figures, I'm looking at
17 page 24 and 25, Figures 3 and 4, assessments of the
18 effectiveness of hardening, hardened circuits; do you see
19 that?

20 A Figures 3, Figure 4, Figure -- yes, I see Figures 3 and
21 4.

22 Q And those take a look at circuits that were hardened one
23 year before, one year after, compared to performance on a
24 control group, correct?

25 A I believe that this looks at -- I would have to validate,
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1 subject to check, the raw data. I believe this data is
2 showing us the before of three years before versus one
3 year after for both the hardened circuits, and yes,
4 versus our control group in the (inaudible) --

5 COURT REPORTER: Our control group -- I'm
6 sorry. Control group in the?

7 A The control group is right next -- the data for the
8 control group is located right next to the data for the
9 hardened circuits.

10 COURT REPORTER: Thank you.

11 Q (By Ms. Andrews): And then in your rebuttal testimony in
12 this case, you provided a three years before and a three
13 years after for circuits hardened, a summary of the
14 results of that assessment is on page 13 to 14 of your
15 rebuttal testimony, right?

16 A Just validating the page numbers. We do have a summary
17 of the same set of data with the exception of three years
18 before is now being compared to three years after on
19 pages MEA-13-Rebuttal and 14-Rebuttal.

20 Q Page 14 is the wire downs, down events, at least in mine?

21 A Yes. Page 14, Table 3, which is the wire down events.

22 Q O.K. And that -- so that, the rebuttal analysis extended
23 the sort of look at the persistence of benefits over a
24 longer period as opposed to just one year to three years,
25 that's pretty much the difference, correct?

1 A The difference is instead of comparing to one year after,
2 it has the data for three years after for those
3 reliability metrics, or for this data. Excuse me.

4 Q Yeah. Thank you. Has the Company conducted an
5 assessment of the effectiveness of PTMM lines hardened, I
6 mean lines that were treated with PTMM?

7 A The Company has, to date, the Company has not done a
8 similar assessment as what we have shown here for
9 hardening. As we have continued to evolve the quality of
10 the PTMM program, we are planning to submit this
11 information in our annual PTMM report that will be
12 submitted to the Commission beginning in 2025.

13 Q That was going to be my next question. The -- is it your
14 understanding that the PTMM effectiveness report that you
15 just mentioned that you'll be filing will provide a
16 before and after for PTMM for lines and circuits that
17 were PTMM treated?

18 A Our plan is to include that reliability data beginning in
19 the 2025 report.

20 Q Would that include a comparison to a control group?

21 A We have not pulled that together yet or discussed
22 specifically if the control group would be included in
23 that analysis or not.

24 Q Do you know when in 2025 that report or assessment is
25 expected to be filed?

1 A I don't recall the due date that we have with the
2 Commission. I believe it's in the second quarter,
3 subject to check.

4 Q You indicated that as you're continuing to evolve the
5 quality of the program; what do you mean by that?

6 A I'm referring back to what we were just talking about in
7 my direct testimony of the improvements that were made
8 following the change to the PTMM program from PTM where
9 we talk about specifically the 2022-23 improvements of
10 the PTMM inspections only and the process improvements
11 that we discussed, if you'd like me to find that page
12 again.

13 Q Page 45?

14 A Page 44, yep. Be on page 44 and extending into page 45
15 of my direct testimony, that's what I'm referring to.

16 Q What would prevent the Company from assessing the lines
17 that were treated with PTMM specifications in 2019-2020,
18 and 2020-21, why not check the, the impacts of those
19 circuits that work?

20 A Because of the changes that we have made and the
21 improvements over the last years, we have not done that
22 assessment. We believe that the circuits that we have
23 been inspecting and performing the construction,
24 associated construction to remediate the defective
25 equipment are more representative of the reliability

1 improvements customers will get from the program going
2 forward.

3 Q Wouldn't you agree that the changes made in the last two
4 years of the program, '22 and 2023, were not different in
5 nature, they were different in number? They're applying
6 the same specification, right? It was just -- right?

7 A Again, I would have to validate if there were any
8 additional updates to the specifications within that
9 timeframe to know if that was included in there, but they
10 are, the majority of those changes were in, as we stated
11 in pages 44 to 45, to the use of the PTMM-only
12 inspections and our ability to identify the defective
13 equipment.

14 Q Would, in an inspection in 2020, would it have followed
15 the visual and the I think it's bore detection standards
16 that are in the specification, were the inspectors
17 following the same inspection standards?

18 A They were following the inspection standards that were
19 valid at that time.

20 Q And they were replacing poles and replacing pole top
21 equipment in accordance with the Company's pole top
22 maintenance specification, right?

23 A That is my understanding.

24 Q So in 2020, as part of the PTMM program, porcelain
25 insulators were replaced, assuming that's what that

1 specification means, with polymer insulators, right?

2 A Are you asking if all poly -- all porcelain insulators
3 were replaced? Can you please repeat your question?

4 Q I am asking whether inspectors who were doing PTMM
5 inspections in 2020 were following the Company's
6 specifications that when they came across a porcelain
7 post insulator, they replaced it, and when they came
8 across a, let's see, arrestors -- let's talk about one
9 we've been talking about -- a porcelain cutout, they
10 replaced it with a polymer cutout?

11 A I would have to take a look at the specific pole top
12 maintenance specification that was active back in 2020 in
13 order to answer that question.

14 Q You have not provided any version of the wood
15 specification, wood pole top maintenance specification
16 other than the one that requires porcelain cutouts to be
17 replaced with polymer cutouts, correct?

18 A I would have to validate in my discovery if we, if we
19 submitted one through discovery, but I don't know that
20 there are any more specifically on the record. I would
21 have to check.

22 Q O.K. And at least according to Mr. Bruzzano's testimony
23 in 2018, it appears that the Company back in 2018 was
24 replacing porcelain cutouts with polymer cutouts?

25 A Let me open that up again. Again referring back to
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1 Mr. Bruzzano's testimony that we spoke about earlier, I
2 believe it is on page 17, it does state that we replace
3 porcelain cutouts with polymer cutouts, and porcelain
4 insulators with polymer clamp-top insulators. What is
5 not listed in here would be the nuance as written in the
6 pole top specification on if it is all or if the
7 requirements for being damaged is a crack or some other
8 criteria.

9 Q O.K. So so far the Company, since the Company has
10 implemented the process changes outlined in your
11 testimony in the second and third set of improvements in
12 2021 through 2023, the Company has not assessed the
13 impact to lines that have been treated with PTMM using
14 the most up-to-date process improvements in terms of the
15 impact to, performance impact, reliability or outage?

16 A To my knowledge, we have not looked at a similar
17 evaluation like we did with the hardening program per my
18 testimony where we looked at three years' performance
19 before and one year after. We are currently waiting to
20 have the full year's performance of 2024 so that we can
21 do, completely do that assessment.

22 MS. ANDREWS: I am going to switch gears
23 to a different topic, and I'm happy to keep going or I'm
24 happy to take a break. It's been about an hour I think
25 that we've been going.

1 JUDGE WALLACE: Let's go ahead and take
2 about a 15-minute break, come back at 2:10.

3 (Recess from 1:54 p.m. until 2:12 p.m.)

4 JUDGE WALLACE: All right. Back on the
5 record. Please continue, Ms. Andrews.

6 MS. ANDREWS: Thank you.

7 Q (By Ms. Andrews): Ms. Elliott Andahazy, I'm going to ask
8 you a few questions about the benefit-cost analysis that
9 the Company provided in this case. It is a -- well,
10 let's start with some foundation. I'm going to try not
11 to go into a confidential record, so I'll just start with
12 that. The Company retained the 1898 Company -- let me
13 rephrase that. DTE retained the 1898 Company to produce
14 a benefit-cost analysis related to, among other programs,
15 the PTMM program, correct?

16 A That is correct.

17 Q And you supported Exhibit A-23 Schedule M13, a whitepaper
18 that relates to the benefit-cost analysis, correct?

19 A That is correct.

20 Q The model itself, the Excel model was provided to the
21 parties in discovery, it's a confidential model or
22 confidential production, correct?

23 A Yes.

24 Q And then in your rebuttal discovery, you sponsored
25 Exhibit A-51 Schedule PP10, which is a discovery response

1 indicating that the model was produced but not producing
2 a copy of the model, correct?

3 A I believe -- when you say -- I don't understand the
4 question regarding not producing a copy of the model. We
5 did have attachments which included the PTMM BCA model.

6 Q But the attachments, to my understanding, were not
7 included in the exhibit? When your testimony was bound
8 in, I, unlike Mr. Kryscynski yesterday, I understood the
9 Company said Exhibit A-51 Schedule PP10, which consists
10 of one page, and when Mr. -- and I'm just -- I'm not
11 trying to make an issue out of anything, but his, when he
12 put the GPM model, the reliability model, the models
13 themselves were produced with a link. In this case, you
14 haven't produced the model itself as a record -- as an
15 exhibit in this case. Or was it your intention to do
16 that?

17 A I may have to ask for advice on how to respond to that
18 one. Based on the one on PP10, it does say please see
19 attached files which contains all the data which supports
20 Table 1 in Exhibit A-23 Schedule M13, and then it has
21 four attachments listed. They do start with NDA as being
22 confidential. I don't know if that responds to your
23 question or not.

24 Q So I think maybe we're talking past each other. Exhibit
25 Schedule PP10 is a discovery response that references

1 attachments, right?

2 A Yes.

3 Q It is not a link to the model as the exhibit in this
4 case, correct?

5 A I think I understand what you're saying now, that we
6 submitted just this one piece of paper without the links
7 as part of the exhibit? Based on what you're saying, if
8 those attachments were not included in here, then that
9 would be correct.

10 Q O.K. If there is a version of the model that is an
11 exhibit in this case, that's what I'm trying to
12 ascertain. It was my understanding there was not, and I
13 don't believe you're saying that I'm incorrect, that the
14 model itself is an exhibit in this case?

15 A Now that I believe I understand your line of questioning,
16 to my knowledge, I believe that is correct.

17 Q O.K. So my point is simply that I'm going to try to ask
18 you questions that are about how the model works, the
19 methodology of the model, but without specifically
20 revealing confidential information in the model, and in
21 particular, information related to the particular
22 circuits and conditions on circuits that were included in
23 the model, and I don't want you to inadvertently reveal
24 confidential information either, which is why I'm saying
25 this.

1 A Thank you.

2 Q O.K. The benefit-cost analysis includes a circuit-
3 specific analysis of about, subject to check, around
4 3,800 distribution circuits, correct?

5 A Subject to check that number, that sounds about right,
6 yes, there is an analysis for each individual circuit.

7 Q O.K. And it includes an -- and I'm going to look at the
8 exhibit just for reference, and you are obviously free to
9 as well, but it's obviously not in the record. The model
10 includes an assessment of what, of each circuit, what it
11 would cost to install or to apply or treat that circuit
12 with the PTMM program, to apply PTMM to that circuit in
13 2024 based on the number of poles and the length and all
14 of the assumptions about the cost of PTMM program?

15 A To make sure I'm understanding, if I'd just like to
16 rephrase that to make sure we have the same
17 understanding, that the model does for each individual
18 circuit come up with a forecasted cost to complete PTMM
19 on that individual circuit based on known poles, pole top
20 equipment locations, yes.

21 Q And that, for purposes of modeling, the model assumes
22 that that PTMM will be applied to the circuit in 2024.
23 Obviously that's not happening, it's just for modeling
24 purposes, that's the year of the investment, correct?

25 A The model has the PTMM cost or investments associated in
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1 2024 for all circuits, yes.

2 Q And the model also -- and it assumes the cost based on
3 the Company's actual expenses or projected costs based on
4 historic experience?

5 A There are assumptions that are built in to the model that
6 uses the average investment required to replace a pole,
7 for example, or the average investment required in order
8 to replace pole top equipment, it uses information out of
9 our GIS system that maps all of the locations on our
10 system to understand number of poles, and then per the
11 whitepaper, there are some assumptions that are made,
12 and -- excuse me. We also utilize what we were seeing,
13 our most recent condemnation rates for poles and pole top
14 equipment locations to calculate essentially an average
15 or an expected amount of condemned poles and pole top
16 locations per circuit to use with the required
17 investments to remediate those condemned areas and then
18 comes up with that calculated amount of what that PTMM
19 investment would be in 2024.

20 Q For each circuit?

21 A For each circuit.

22 Q Yep. Thank you. And then the model also has, has a
23 do-nothing scenario; is that right?

24 A Yes. The baseline scenario is referred to as the
25 do-nothing scenario in the model.

1 Q And in the do-nothing scenario, the Company -- the model
2 assumes that there will be no visual pole inspections at
3 all, correct?

4 A The do-nothing assumes there is no pole top maintenance
5 modernization inspections conducted, correct.

6 Q No pole inspection, no pole top inspection, no physical
7 inspections of poles, no inspections whatsoever, correct?

8 A It assumes that we are running the equipment to failure,
9 both poles and pole top equipment.

10 Q There are no treatments of any kind to any of the
11 equipment, the poles or the pole tops, right?

12 A Correct. It is assuming everything is run to failure.

13 Q And the study, the cycle or the period of this
14 assessment, it's a 40-year period, it's 2024 through
15 2063, correct?

16 A I would have to just doublecheck the years, but yes, it
17 is a 40-year assessment.

18 Q So the do-nothing approach would not meet the
19 Company's -- the Commission's standards for pole
20 inspections and pole, pole and pole top inspection 10- to
21 12-year inspection cycle?

22 A If I may just clarify, please. Technically speaking, we
23 could be inspecting and not remediating or fixing any of
24 the damaged equipment or poles that we find. Our intent
25 is to ensure that we are able to remediate and construct

1 all failed equipment in the field that we identify
2 through those inspections. So assuming that when you say
3 it does not meet the inspection criteria, I'm going to
4 say it does not meet the inspection and associated
5 construction criteria that we are trying to get to today,
6 yes, to meet that 10- to 12-year process -- or cycle.

7 Excuse me.

8 Q For each circuit, the model estimates the future avoided
9 costs or the savings on the circuit to the Company as a,
10 I want to say avoided reactive cost, emergent react, I
11 think it calls it the emergent reactive benefit; is that
12 correct?

13 A Yes, it does calculate the net present value of the
14 avoided cost the Company would have to incur in order to
15 remediate emergent trouble that is forecasted throughout
16 that 40-year timeframe.

17 Q So over 40 years, between 2024 and 2063, if the Company
18 did nothing, it would have this event and that would
19 require this repair, capital, other capital investments
20 and other work, and it assesses that over the, you know,
21 on an annual basis based on an assumed number of outage
22 events duration, correct?

23 A Yes, it makes those calculations based on assumed failure
24 rates that we would see for pole top equipment and poles.

25 Q And then the model makes, provides a ratio of the cost,

1 program cost to the emergent replacement benefit,
2 correct?

3 A So there are actually two ratios that are collected;
4 there is a ratio that is in, located in the model that
5 explicitly compares the emergent costs that we are
6 projecting we would see if we did, if we performed the
7 do-nothing scenario and ran everything to failure
8 compared to the investment that it would require for us
9 to do PTMM on each given circuit in 2024. And again,
10 that's the present value of those emergent forecasted
11 costs. The formal benefit, though, that the model is
12 really looking at is the total benefit to the customer,
13 which also includes the calculated benefits the customer
14 sees per using the LBL ICE calculator as well.

15 Q O.K. So I just -- so the model, you would agree with me
16 the model separates out the benefit of the avoided or the
17 emergent reactive benefit relative to the cost of the
18 program. So the Company avoided these costs and the
19 Company incurred the costs to install, to do the
20 treatment, and it provides a ratio of Company costs to
21 Company benefits, correct, as well as -- and we'll get to
22 that in a minute -- the customer benefits?

23 A I am just validating in the model that I am looking at,
24 and there is a calculation that is made that compares the
25 emergent reactive benefits that the Company alone

1 receives for not investing in the do-nothing scenario and
2 the emergent trouble versus the investment for PTMM.

3 Q And on a -- across the analysis for all circuits
4 combined, would you agree, and I can refer you to I think
5 it's in your rebuttal you provided, the Company, the
6 Company benefits, the avoided emergent reactive costs
7 total, looking at your rebuttal page 28, \$1.7 billion
8 over the 40-year period in emergent reactive reductions
9 across all circuits?

10 A The 1.7 billion approximately, that is --

11 Q Right.

12 A Yeah, that is the sum of those forecasted do-nothing
13 scenario emergent investments that would be required over
14 that timeframe.

15 Q And would you agree with me, I think you put it in a
16 discovery response, you summed the total PTMM investment
17 for all circuits was about 2.6 billion?

18 A I would have to validate my discovery response, but yes,
19 I do believe we turned it in, and that sounds close to
20 what that estimate is, which is just a sum of the column
21 that has all of the PTMM investment required if we were
22 to do PTMM on each individual circuit in 2024.

23 Q Right. And just at a high level and across-the-board
24 level, PTMM is not positive cost-benefit on a system-wide
25 basis comparing PTMM investment to the Company's avoided

1 emergent reactive costs, correct?

2 A There are -- so we have it calculated for each circuit
3 and for -- you're asking for the sum if I look at the sum
4 of the emergent cost versus the sum of the PTMM
5 investment, if we looked at it from that perspective,
6 that is less than a 1.0 value.

7 Q O.K. And then if we look at each circuit, subject to
8 check, it looks like few to any circuits are, have a
9 positive, a 1 or above score, and a 1 is where the
10 benefits equal the costs, right, so above 1 is when the
11 benefits exceed the costs, right?

12 A I would have to look through all of the over 3,000
13 circuits to validate. There are some that are above and
14 some below that 1.0 demarcation, though.

15 Q So if we sort, and -- will it let me? I'm in the summary
16 tab of the model, and if I sort the BCA emergent
17 replace -- BCA emergent replacement risk only, we get a
18 count of 86 circuits that are above 1, subject to check?

19 COURT REPORTER: Can I clarify, is that B
20 as in boy or V as in Victor?

21 MS. ANDREWS: B for benefit as in boy.

22 COURT REPORTER: Thank you.

23 A I have sorted column J largest to smallest; my number is
24 a little bit different, but it is close.

25 Q (By Ms. Andrews): O.K. So it's --

1 A It is just over a hundred.

2 Q O.K. So it's a fraction of the 3,800 or so circuits that
3 were in the study, about 2%, 3%?

4 A I would have to check the math, yeah.

5 Q O.K. So you reference, you mentioned earlier that the
6 model also calculates over a 40-year study period the
7 benefits to customers in avoided outage-related costs,
8 correct?

9 A Correct. The model calculates, based on the forecasted
10 emergent trouble reductions, calculates the benefit to
11 the customer using the LBL ICE calculator for those
12 associated outages.

13 Q So the model calculates that an outage in, the net
14 present value of an outage in, say, 2060 would affect a
15 customer on a circuit for a certain amount of time, and
16 the cost to that customer in terms of lost product, lost
17 work, lost refrigerator items, and other impacts to the
18 customers, the net present value of that is the customer
19 outage benefit, correct?

20 A It takes the same emergent trouble information that is
21 used to calculate the do-nothing scenario and the
22 investment the Company would have to make in order to
23 remediate that emergent trouble, takes that same data and
24 calculates the impacts to the customer using that ICE
25 calculator, which does have the impact to the customers

1 for items that you mentioned.

2 Q And in, according to your rebuttal testimony, the sum of
3 those benefits is \$8.2 billion, correct, system wide?

4 A Per MEA-28, yep, on line 17, it says just over \$8.2
5 billion.

6 Q So the Company's, the benefits of a -- to the extent a
7 particular circuit is positive, we were talking about the
8 emergent replacement risk only, most circuits are not
9 positive or they are less than 1, but in terms of when
10 you combine the emergent reactive and the customer outage
11 benefit, the model provides a score, and some of the
12 circuits score above 1 and some score below 1, correct?

13 A Yes, that is correct.

14 Q And on a circuit-by-circuit basis, there's a far more
15 variety in terms of the customer outage benefits;
16 correct? Some circuits score much higher, say 15 or 16,
17 and some score zero or below, well, zero and a fraction,
18 up to 1, there's a wide variety of scores, correct?

19 A There is a large range of scores, yes, that comes from
20 the customer benefit associated with those emergent
21 trouble values, some are above that 1.0 mark and some are
22 below.

23 Q O.K. So the benefit-cost analysis, the BCA model, does
24 not tell us -- it provides us on a circuit by circuit, or
25 provides the Company on a circuit basis whether over

1 40 -- whether between the years 2024 and 2063 the
2 benefits to customers exceed the costs in 2024 of
3 modernizing that circuit; is that fair?

4 A You said that the benefits if you include the emergent
5 reactive investment plus the customer avoided benefits
6 compared to the PTMM investment that we would have to
7 make today over that timeframe, yes. I was thinking out
8 loud, recapping what you said.

9 Q The BCA does not attempt to determine whether in fact a
10 circuit that has been treated with PTMM achieves a
11 reduction in outage events, does it?

12 A I'm not sure that I understand your question.

13 Q The BCA is a projection of forward potential benefits,
14 correct?

15 A Correct.

16 Q It does not attempt to look at a circuit that has
17 actually been treated with pole top PTMM specifications
18 and what its performance is after treatment, correct?

19 A It is not looking at an actual circuit that has already
20 been, gone through PTMM in the recent past and its
21 performance going forward. There is, in the PTMM
22 investment scenario tab, there is a recognition that even
23 when PTMM is completed, there is still an expectation
24 that there may be emergent trouble that continues to
25 occur on that circuit for whatever -- well, there are

multiple reasons that cause trouble to occur, and so there is a factor that is taken into account of the fact that we will have to continue to forecast some level of investment to remediate those emergent trouble items as they come up over the 40-year timeframe as well.

Q So even though the Company had completed its most recent iteration of pole top maintenance and modernization to some circuits in 2022, the BCA did not attempt to look at the performance on those circuits before and after PTMM, correct?

A The BCA was based off of the expertise of 1898 and a model that they have used with multiple other utilities, I believe it's 19, although I would have to validate in either my rebuttal testimony or discovery questions, and their expertise of failure data, it did not look at the actual failure data of circuits that we had previously PTMM'd.

Q And the Company has the data on its 2022, at least at the time of the BCA report, had its 2022 circuits that had gone through PTMM, that data is available, correct, it was available to the 1898 Company?

A So the Company would have had -- at the time the BCA was conducted earlier in 2024, the Company would have known obviously which circuits we completed PTMM on in 2022, and the outage management system would have had

1 historical record of emergent trouble on said circuits.

2 MS. ANDREWS: O.K. Your Honor, if I may
3 just have five minutes off the record to confer, I
4 believe I may not have any other questions for this
5 witness, but I would like to just -- oh, you know what,
6 and I'm going to still need to admit a bunch of exhibits,
7 but I don't intend to ask any questions about them.

8 JUDGE WALLACE: O.K. So off the record
9 for five minutes.

10 MS. ANDREWS: Thank you.

11 MS. JOHNSON-BACON: Thank you.

12 (Recess from 2:38 p.m. until 2:52 p.m.)

13 JUDGE WALLACE: O.K. Back on the record.
14 Ms. Andrews, please continue.

15 MS. ANDREWS: Thank you. I don't have
16 any further questions for Ms. Elliott Andahazy, but I
17 would like to move at this point for the admission of
18 some exhibits, and if you'll bear with me, I'll read
19 through them. Exhibit MEC-39, which is the Response to
20 MNSCDE-17.18; Exhibit MEC-40, which is the Response to
21 MNSCDE-17.20; Exhibit MEC-40, which is the Response to
22 MNSCDE-18.27.

23 JUDGE WALLACE: Did you mean 41?

24 MS. ANDREWS: I'm sorry. 41. 41 is
25 MNSCDE-18.27. Exhibit MEC-42, which is the Company
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1 Response to MNSCDE-18.8 and -30; MEC-43, which is the
2 Company Response to MNSCDE-18.29; Exhibit MEC-44, which
3 is the Company Response to MNSCDE-18.31; Exhibit MEC-45,
4 which is the Company Response to MNSCDE-18.32; Exhibit
5 MEC-46, which is the Company Response to MNSCDE-18.33c;
6 Exhibit MEC-47, which is the Company Response to
7 MNSCDE-18.33d and e; MEC-48, which is the Company
8 Response to MNSCDE-18.33g and h; Exhibit MEC-49, which is
9 the Company Response to MNSCDE-18.34; Exhibit MEC-50,
10 which is the Company Response to MNSCDE-18.35
11 and -15.41a, without the Excel attachment; Exhibit
12 MEC-51, which is the Company Response to MNSCDE--18.36;
13 Exhibit MEC-52, which is the Company Response to
14 MNSCDE-18.41; Exhibit MEC-53, which is the Company
15 Response to MNSCDE-18.42; Exhibit MEC-44 -- 54, sorry,
16 which is the Company Response to MNSCDE-18.43 and -44;
17 Exhibit MEC-55, which is the Company Response to
18 MNSCDE-19.12a and b; MEC-56, which is the Company
19 Response to MNSCDE-9.16 and -17; MEC-57, which is the
20 Company Response to MNSCDE-19.19; MEC-58, which is the
21 Company Response to MNSCDE-19.35 and -36; MEC-68, which
22 is the Company Response to MNSCDE-15.47h and an Excel, a
23 PDF of an Excel; Exhibit MEC-73, which is the Company
24 Response to MNSCDE-19.28; and finally, MEC-74, which is
25 the Company Responses to MNSCDE-19.29, -30, -33, and -34.

1 JUDGE WALLACE: O.K. Is there any
2 objection to the admission of Exhibits MEC-39 through
3 MEC-58, MEC-68, MEC-74, and MEC-73?

4 MS. JOHNSON-BACON: No objection.

5 JUDGE WALLACE: So 39 to 58, 68, 73, and
6 74.

7 MS. JOHNSON-BACON: No objection, your
8 Honor.

9 JUDGE WALLACE: O.K. Hearing no
10 objection, these exhibits are admitted.

11 Ms. Johnson-Bacon, do you have any
12 redirect for your witness?

13 MS. JOHNSON-BACON: I do not have any
14 redirect, your Honor, but I do have a clarification for
15 the record. We kind of went back and forth early in
16 cross-examination about whether A-51 Schedule PP10 was
17 merely the discovery response. I misspoke originally, it
18 should include a Microsoft Excel link to that model that
19 was produced both in discovery as well as in support as
20 an exhibit to Ms. Elliott Andahazy's rebuttal testimony.
21 It was sent as a confidential file, which might have
22 caused some of the confusion. Clearly everyone has the
23 model, or at least Ms. Andrews does, but we'll make sure
24 that we correct the administrative error with respect to
25 loading. That Microsoft Excel link to the model should

1 be in the record.

2 JUDGE WALLACE: O.K. All right. And
3 again, that attachment to A-55 -- is it A-55 or A-53?
4 Whatever. PP10.

5 MS. JOHNSON-BACON: Correct. A-51
6 Schedule PP10.

7 JUDGE WALLACE: A-51 Schedule PP10, the
8 attachment is confidential, the discovery response is
9 not?

10 MS. JOHNSON-BACON: Correct.

11 JUDGE WALLACE: All right. If need be,
12 we can clarify that again when we actually admit all the
13 Company's exhibits at the close of cross.

14 So you indicated that you don't have any
15 redirect for your witness. Ms. Elliott Andahazy, thank
16 you very much, and you are excused.

17 (Witness was excused.)

18 - - -

19 JUDGE WALLACE: Let's see. Let's go back
20 off the record for a second.

21 (Off-record discussion, 2:59 p.m. until 3:02 p.m.)

22 JUDGE WALLACE: All right. Well, back on
23 the record, then, just briefly. We have concluded cross-
24 examination for today, and I will see everybody back on
25 Monday. We have a second Teams meeting that's

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1 confidential set up for Monday, and I think it will go
2 smoother than it did today.

3 And other than that, does anybody else
4 have anything that we need to address on the record? (No
5 response.)

6 All right. Well, thank you all very
7 much. We are adjourned for today, and I will see you on
8 Monday morning.

9 (Collective "Thank you.")

10 (At 3:04 p.m., the hearing was adjourned to Monday,
11 September 9, 2024, for continued cross-examination.)

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C E R T I F I C A T E

I, Lori Anne Penn (CSR-1315), do hereby
certify that I reported in stenotype via Microsoft Teams
the proceedings had in the above-entitled matter, that
being Case No. U-21534, before Sally L. Wallace, J.D.,
Administrative Law Judge with Michigan Office of
Administrative Hearings and Rules, for the Michigan
Public Service Commission, Lansing, Michigan, on Friday,
September 7, 2024; and do further certify that the
foregoing transcript, consisting of Volume 4-PUBLIC
RECORD, pages 613-1115, constitutes a true and correct
transcript of my stenotype notes.



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Dated: September 7, 2024