

DTE Electric Company
One Energy Plaza, 1635 WCB
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May 8, 2024

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

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

Dear Ms. Felice:

Attached for electronic filing in the above captioned matter is DTE Electric Company's revised Direct Testimony of Witness Morgan Elliott Andahazy. Also attached is the Proof of Service.

Very truly yours,

Paula Johnson-Bacon

PJB/erb
Attachments
cc: Service List

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-21534

QUALIFICATIONS

AND

REVISED DIRECT TESTIMONY

OF

MORGAN ELLIOTT ANDHAZY

DTE ELECTRIC COMPANY
QUALIFICATIONS AND REVISED DIRECT TESTIMONY OF MORGAN
ELLIOTT ANDAHAZY

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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

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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.

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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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1 **Q14. Is the Company proposing recovery for any additional investment in these**
2 **programs through the IRM beyond the test year of this case?**

3 A14. Yes, as described by Company Witness Foley, the Company is proposing a two-year
4 extension of the IRM (i.e., calendar years 2026 and 2027). As part of that extension the
5 Company is proposing recovery of additional Breaker Replacement Program
6 investment and URD Replacement Program investment as captured in Exhibit A-33,
7 Schedule X1, Lines 4 and 5.

8

9 **Q15. Is the Company proposing any additional programs be authorized for IRM**
10 **treatment beyond the test year of this case?**

11 A15. Yes, as part of the proposed two-year IRM extension described by Company Witness
12 Foley, the Company is proposing that the Pole and Pole Top Maintenance &
13 Modernization (PTMM) program be authorized for IRM treatment. The Company is
14 proposing \$150 million of capital investment in 2026 and \$200 million of capital
15 investment in 2027 for this program, as captured in Exhibit A-33, Schedule X1, Line
16 7.

17

18 **Q16. Why is the Pole and Pole Top Maintenance & Modernization (PTMM) program**
19 **a good candidate for IRM treatment?**

20 A16. There are three screening criteria that the Company used to identify the capital
21 programs it proposed to be authorized for IRM treatment. Specifically, the Company
22 looked for programs that had the following characteristics:

23

- Critical to customer safety, reliability, and/or resiliency

24

- Sufficient size and duration

25

- Well-understood scope

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2

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

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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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1 **Q18. What programs and projects fall under the Infrastructure Resilience and**
2 **Hardening Pillar?**

3 A18. The Infrastructure Resilience and Hardening Pillar consists of the following programs
4 and projects:

- 5 • 4.8kV Hardening Program
- 6 • Pole and Pole-Top Maintenance and Modernization (PTMM) Program
- 7 • Substation Risk Projects
- 8 • Frequent Outage Programs (CEMI²)
- 9 • Cable Replacement Program (System Cable)
- 10 • Underground Residential Distribution (URD) Replacement Program
- 11 • Breaker Replacement Program
- 12 • Mobile Fleet Program
- 13 • Pontiac Vaults Projects
- 14 • 40kV: Automatic Pole Top Switch Program
- 15 • Disconnect and Switcher Replacement Program
- 16 • Steel Pole Highway Crossings Program
- 17 • Batteries and Chargers Replacement Program
- 18 • SCADA Pole Top Device Replacement
- 19 • Substation Regulator Replacement
- 20 • Portable Generators Program

21

22 **The 4.8kV Hardening Program**

23 **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
- 17 • Test all utility poles that have Company equipment attached and replace or
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

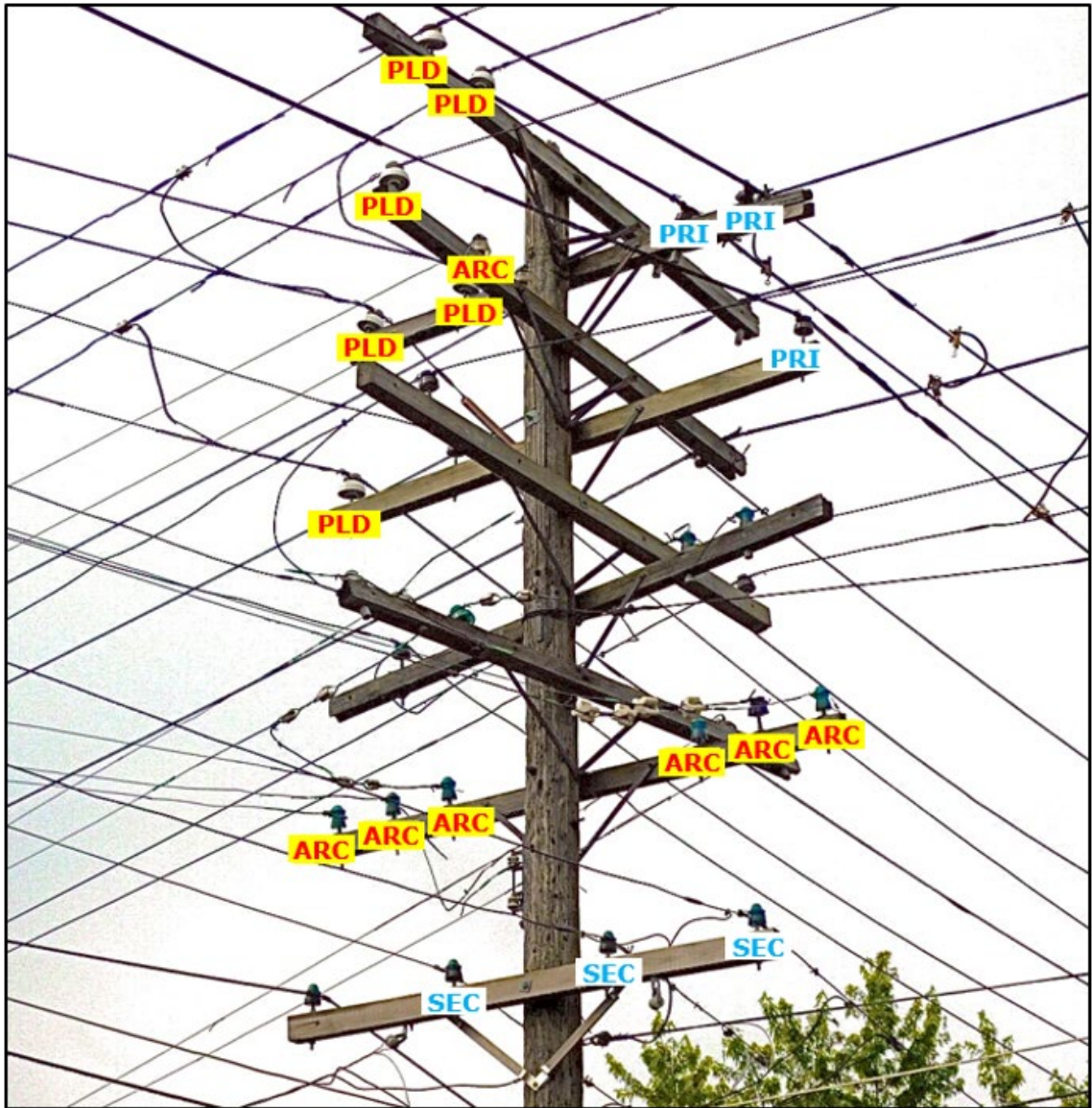
6 Figures 1 and 2 show examples of before and after the 4.8kV Hardening work activities

7 are completed.

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Figure 1. Before Hardening – Example



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PLD: DPLD Distribution Wire

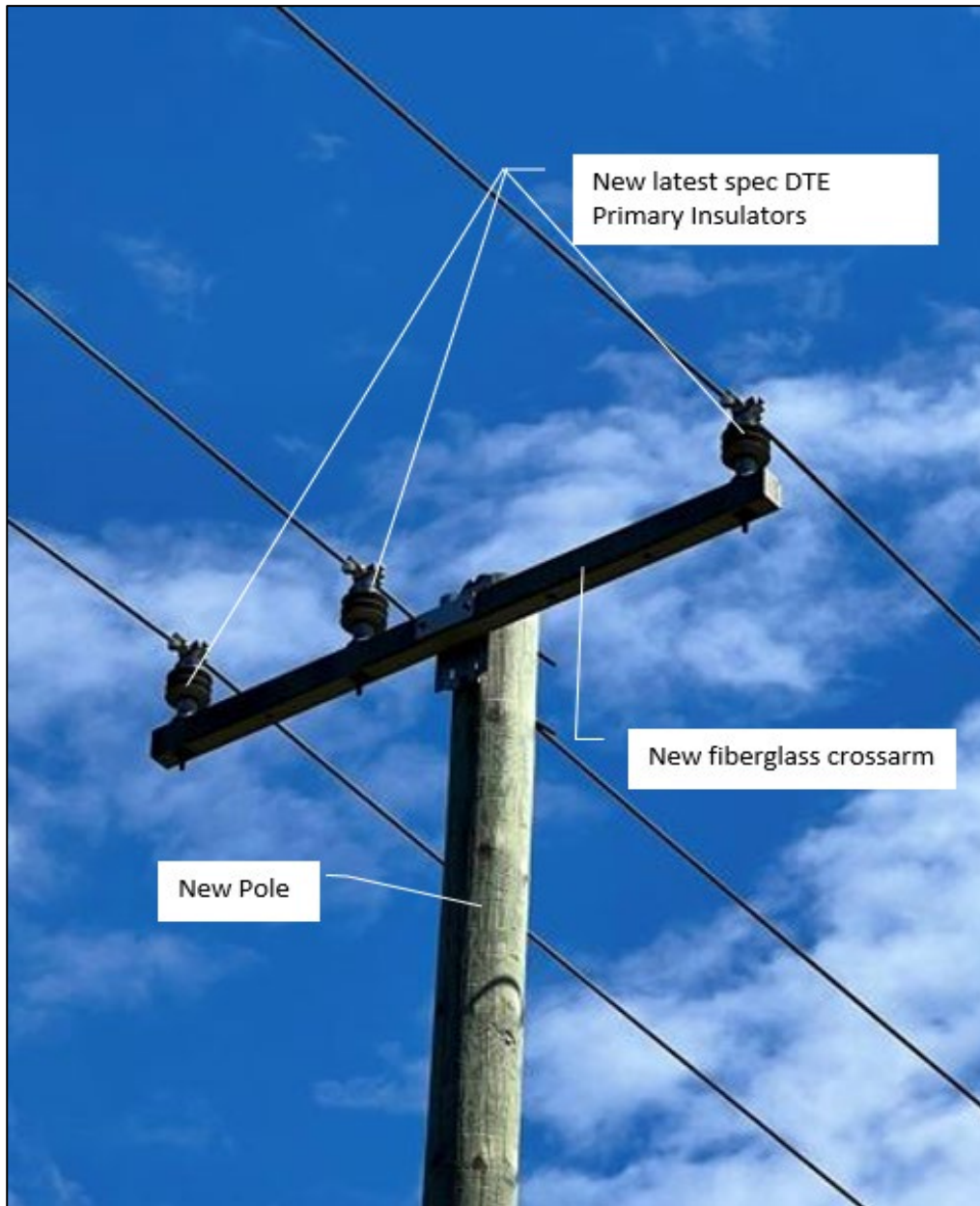
ARC: DPLD Arc Wire

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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1 conversion takes much longer than hardening. ... the Commission
2 approves the requested bridge period and test year funding and expects
3 to see results in DTE Electric's next rate case, including an accelerated
4 removal of the arc wire as discussed by the Staff. (U-21297 -
5 Commission Order, December 1, 2023, p. 93-94)

6

7 **Q23. What stakeholder engagements for the 4.8kV Hardening Program were required**
8 **by the Commission in Order No. U-20836?**

9 A23. The Company was directed to hold stakeholder engagements in the first quarter of 2023
10 covering the following items:

- 11 • Complete a full analysis that demonstrates the specific costs of hardening,
12 conversion, distributed energy resources (DERs), tree trimming, and/or other
13 alternatives compared with the benefits, such as improving safety and reducing
14 System Average Interruption Index (SAIDI) and System Average Interruption
15 Frequency Index (SAIFI).
- 16 • Conduct an analysis of the capabilities/constraints of the 4.8kV system and how
17 it affects the use of DERs and electric vehicles (EVs) compared to conversion
18 to a 13.2kV system.
- 19 • Complete a full analysis and comparison of alternatives to hardening including
20 use of DERs and EVs compared to conversion to a 13.2kV system.
- 21 • Complete a full analysis of optimal reliability-focused distribution technologies
22 and plan a course of action for arriving at an equitable future for environmental
23 justice and other disadvantaged communities.
- 24 • Calculate the miles of arc wire removed to date, the estimated miles of arc wire
25 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.

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Table 1. Hardening Program Alternatives Overview

	Arc Wire Removal	Improved Reliability	Improved Safety/ Wire down	Improved Capacity	Cost Level	Execution Complexity
Tree Trimming					Low	Low
PTMM					Low	Low
1 Arc Wire Removal					Medium	Low
2 4.8kV Hardening					Medium	Low
3 Pre-conversion					High	Medium
4 Conversion					High	High
5 Microgrids					Very High	Very High
DERs					Medium	Medium
Energy Efficiency					Low	Medium
Storage					High	Medium

Selected for Consideration

Increasing difficulty

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

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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?

8

9

10

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.

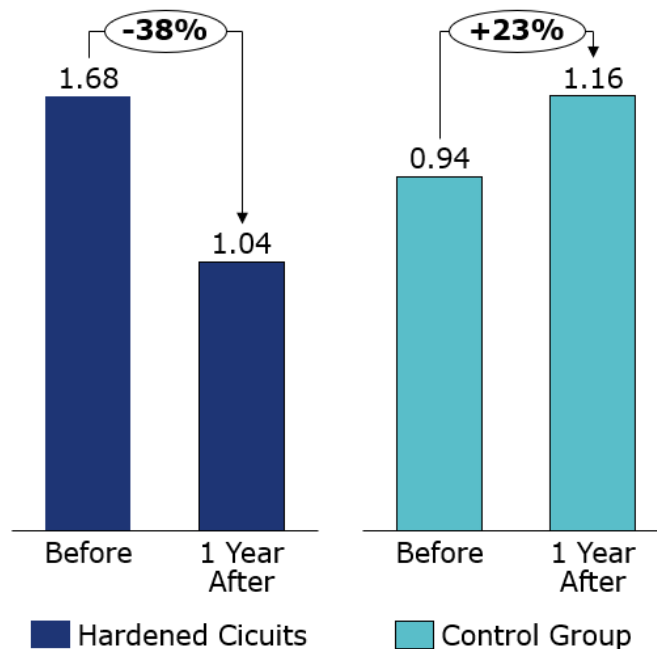
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4 All-Weather SAIFI reflects the frequency of the outage events experienced by
5 customers on the circuits regardless of weather conditions. SAIDI Ex-MEDs is an
6 indicator of the amount of time customers are without power excluding the most
7 significant 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



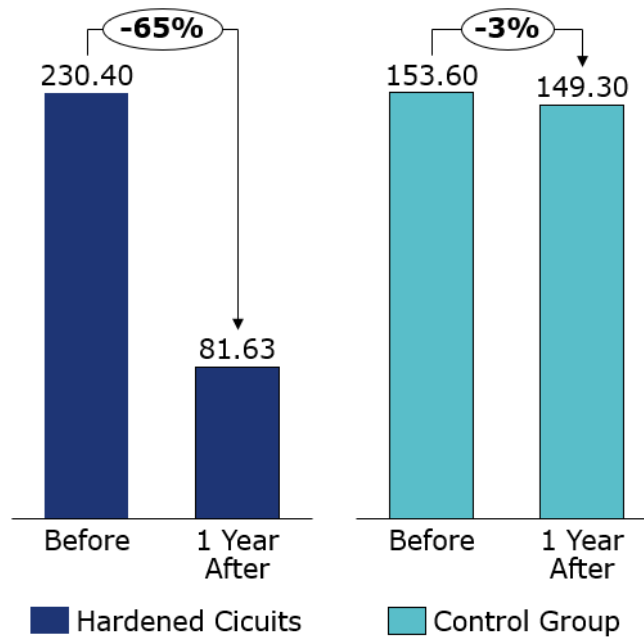
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⁸ Major Event Days (MEDs) is an industry term that denotes a day in which a utility experienced a catastrophic event which exceeds reasonable design or operational limits of the electric power system and during which at least 10% of the customers within an operating area experience a sustained interruption during a 24-hour period. More information about MEDs and their calculation can be found at <https://cmt.ee.org/pes-drwg/wp-content/uploads/sites/61/2003-01-Major-Events-Classification-v3.pdf>.

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1 Figure 3 displays the All-Weather SAIFI improvement of hardened circuits vs. the
 2 control group; the customers on hardened circuits experienced a 38% improvement in
 3 All-Weather SAIFI, while the control group circuits degraded by 23%, resulting in a
 4 net improvement of 61% for hardened circuits.

5 **Figure 4. 4.8kV Hardening SAIDI excluding MEDs**

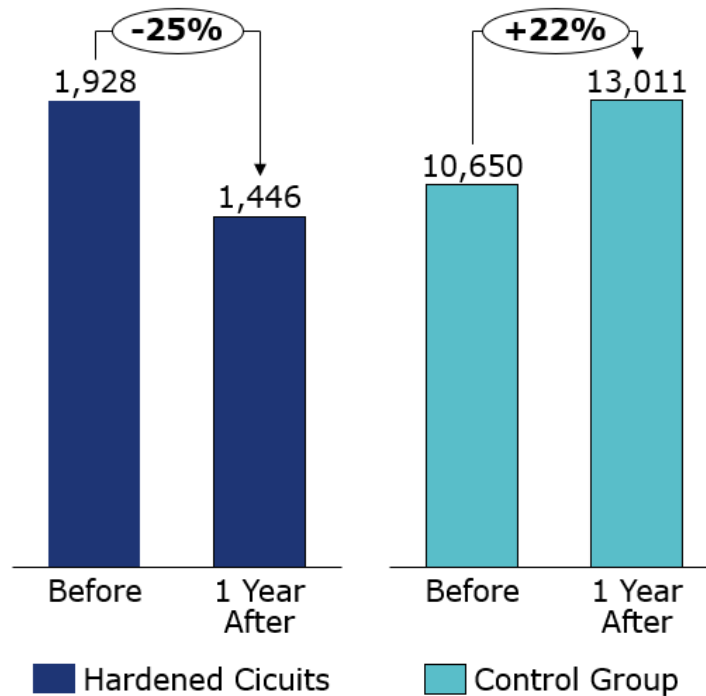


6
 7 Figure 4 displays the SAIDI Ex-MEDs improvement of hardened circuits vs. the
 8 control group; the customers on hardened circuits experienced a 65% improvement in
 9 SAIDI Ex-MEDs, while the control group improved by 3% improvement, resulting in
 10 a net improvement of 62% for hardened circuits.

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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?

9

10

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

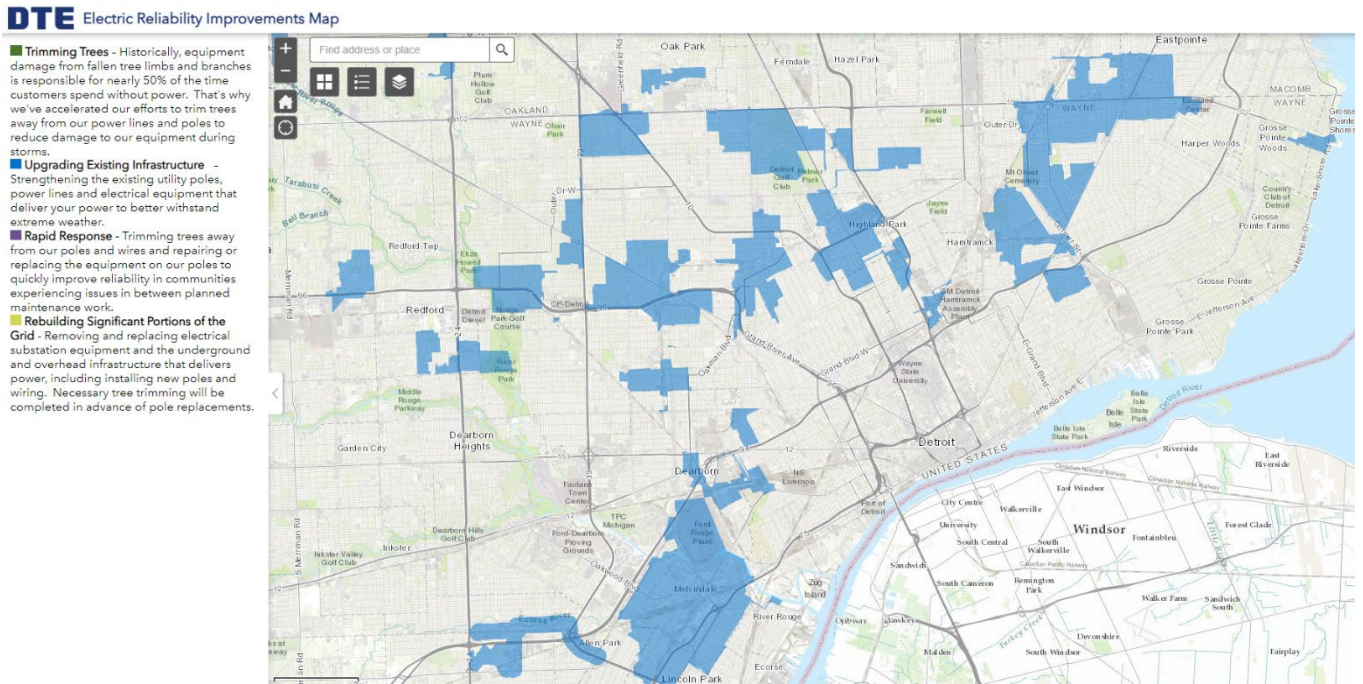
5 **Q38. How can customers stay informed about 4.8kV Hardening work being performed**
6 **in their area?**

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.

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Figure 6. Upgrading Existing Infrastructure Map



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3 **The Pole and Pole-Top Maintenance and Modernization Program (PTMM)**



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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.

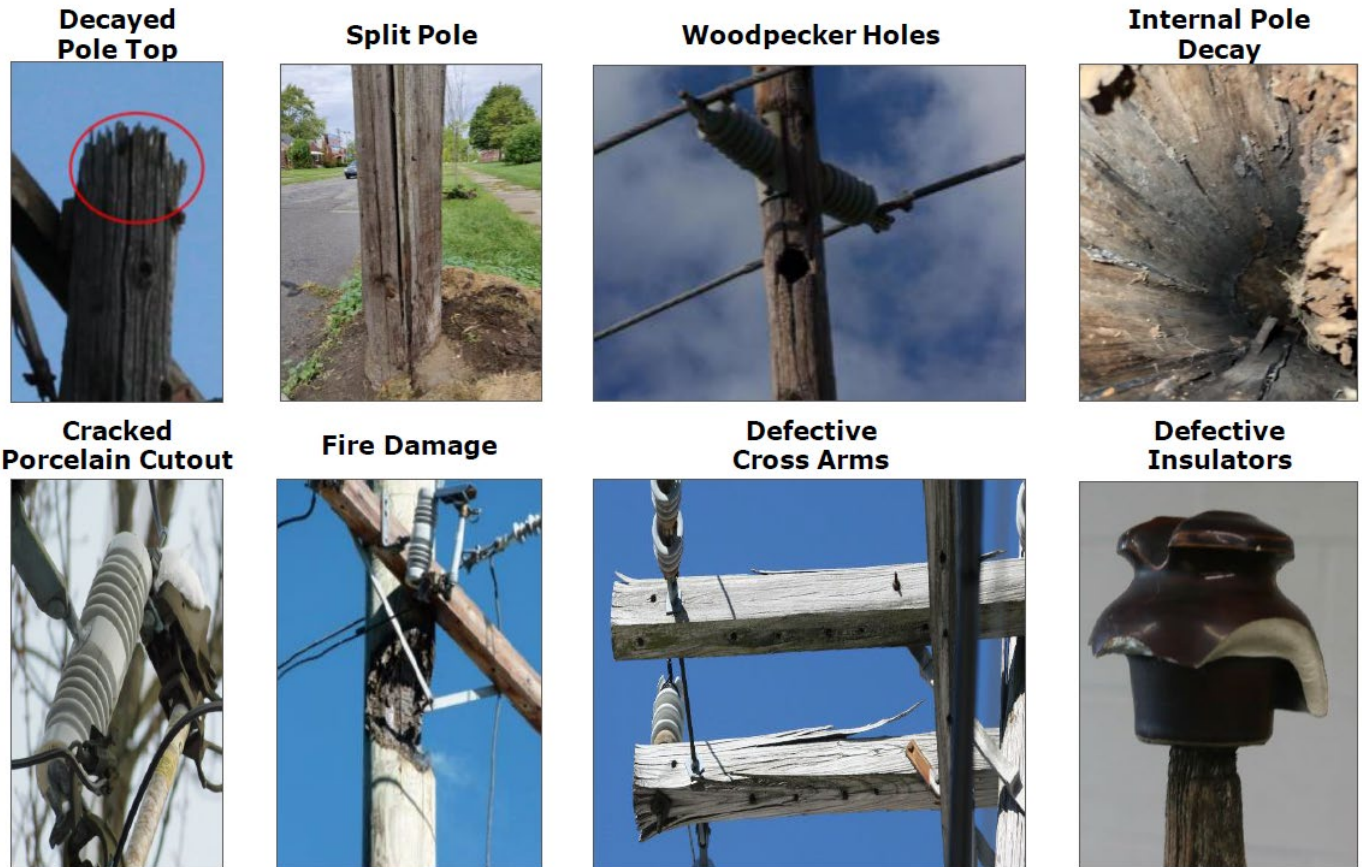
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Figure 7. Pole and Pole-Top Defect Examples

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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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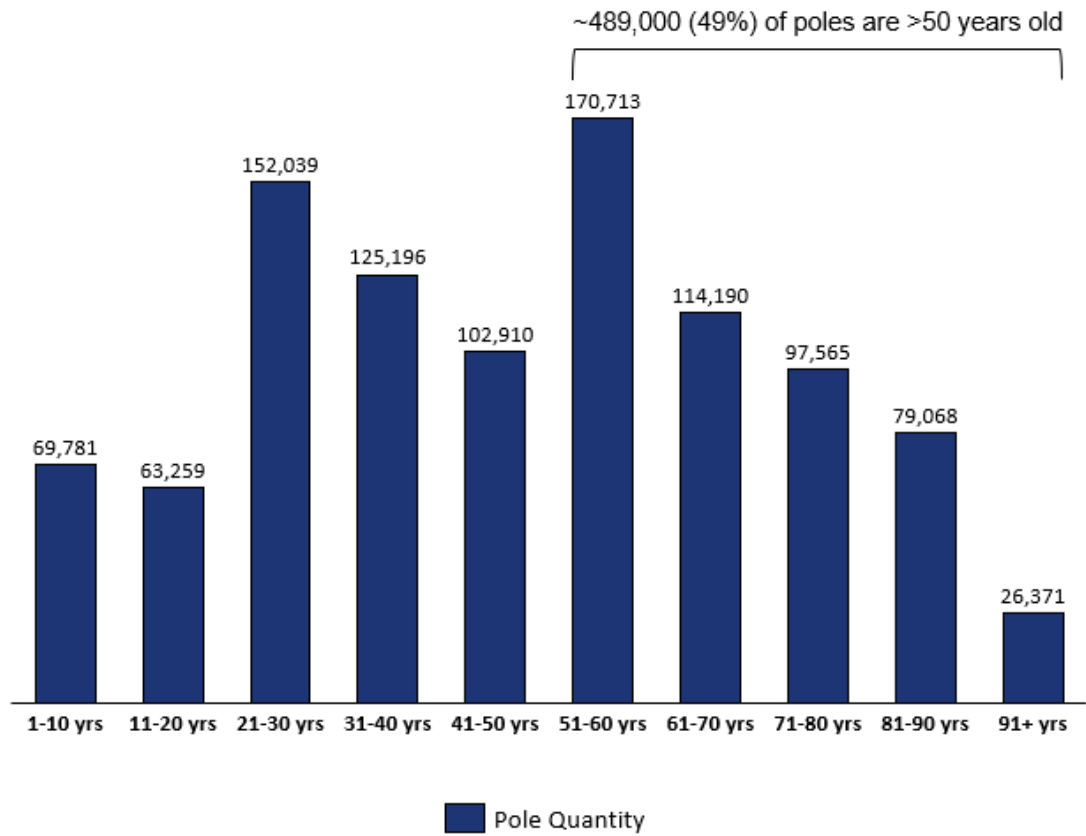
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Figure 8. DTEE Poles by Age

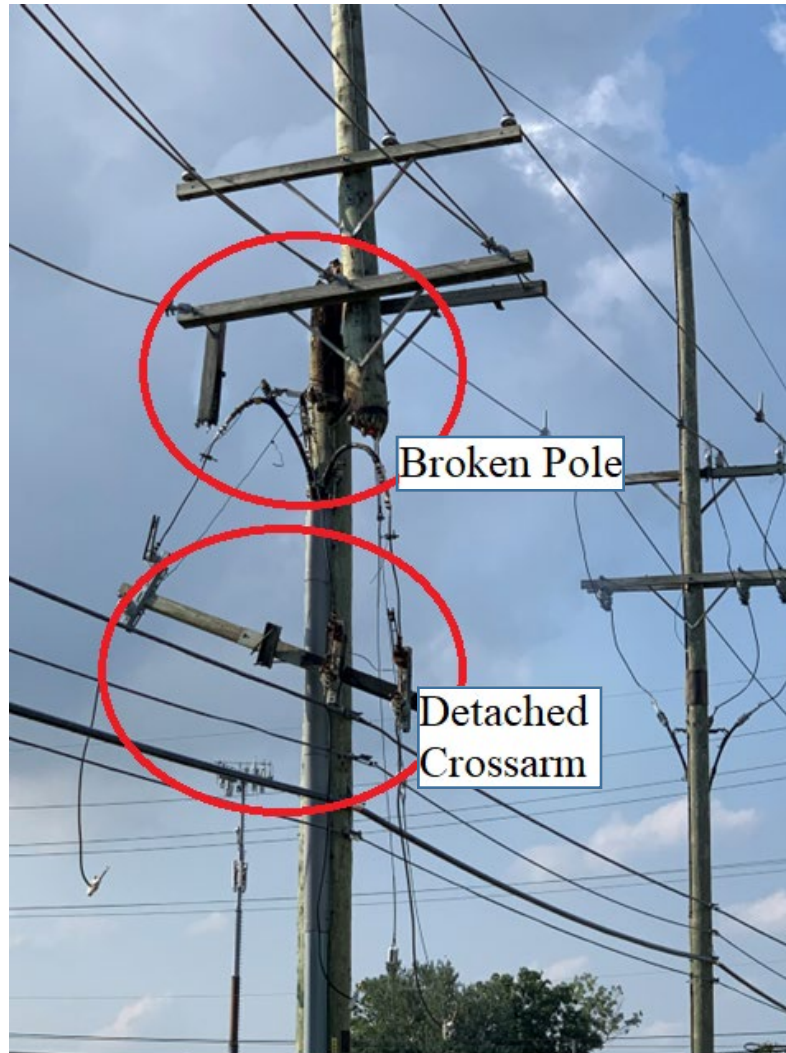


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Aging poles and pole-top equipment increase the risk of overhead equipment failures, which can subsequently cause outages. In addition to outages, examples of incidents that can occur in the event of pole and pole-top equipment failures include property 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



2

3

Pole and pole-top maintenance programs are standard utility industry programs that inspect circuits for damaged or defective poles and pole-top equipment, replacing them before they cause failures. Details regarding industry benchmarking the Company has conducted can be found below.

4

5

Q41. What benchmarking has the Company performed on PTMM?

6

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

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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

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In addition to industry utility benchmarking, the Company consulted multiple industry expert publications and guidelines when developing and updating its PTMM program policies, as noted in Table 7.

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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)	<ul style="list-style-type: none"> 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	<ul style="list-style-type: none"> 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	<ul style="list-style-type: none"> 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 <ul style="list-style-type: none"> 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	<ul style="list-style-type: none"> 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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7

Q44. Does the PTMM Program replace poles and pole-top equipment based solely on age?

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No.

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.

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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



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

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- Cutouts

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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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1 are calculated by totaling the investment forecasted to properly complete pole and pole-
2 top inspections, pole remediation and reinforcements, and pole and pole-top equipment
3 replacements required per the inspection process. The overall average system benefit
4 cost ratio for the system was calculated at 3.8, meaning if PTMM could be conducted
5 on 100% of the Company's distribution grid, the benefits realized by the customers for
6 completing PTMM would be 3.8 times greater than the benefits realized if the
7 Company decided to run all poles and pole-top equipment to failure. The PTMM BCA
8 Whitepaper is included to this instant case as Exhibit A-23, Schedule M13.

9

10 **Q53. What changes has the Company made to its PTMM program in recent years?**

11 A53. The Company's PTMM program has gone through a transformation over the past few
12 years to support a more resilient overhead infrastructure, including alignment with the
13 industry standards discovered through benchmarking activities. The first
14 improvements the Company implemented followed the first set of benchmarking in
15 2018 and 2019, and included updating the pole inspection process (as defined above),
16 and transitioning the previous Pole Top Maintenance (PTM) Program to the Pole and
17 Pole-Top Maintenance and Modernization Program. The addition of "Modernization"
18 simply meant that when a pole, or piece of pole-top equipment failed inspection, the
19 Company would no longer replace like-for-like, rather the equipment would be
20 replaced with the equipment that met the new, higher-level specification to incorporate
21 more modernized equipment into the field.

22

23 The second set of improvements were implemented in 2021 and 2022, and included
24 only using PTMM inspections solely (and no longer utilizing Joint Use inspections) to
25 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

22

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1

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

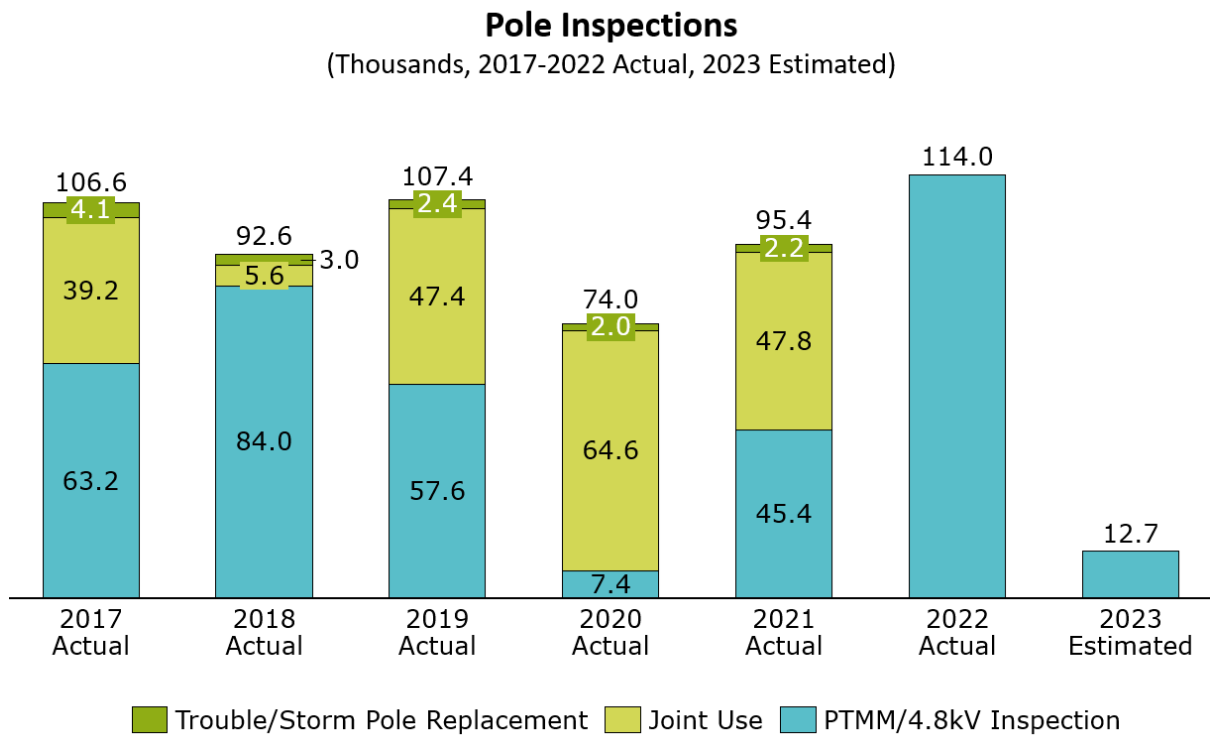
10 **Q56. Why did the PTMM program complete fewer inspections in 2023 than in prior**
11 **years?**

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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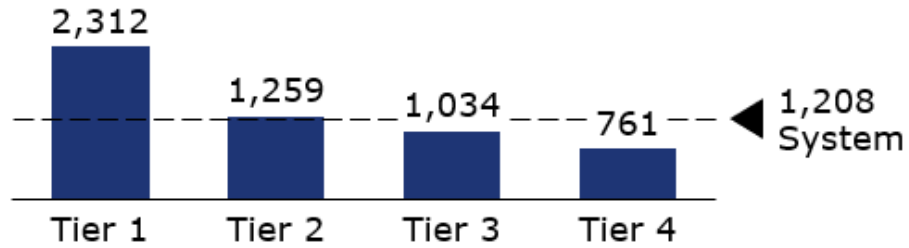
1 circuits ranked as Tier 1 and Tier 2 have worse AW SAIFI and AW SAIDI performance
2 than Tiers 3 and 4 and the system-wide average.

3

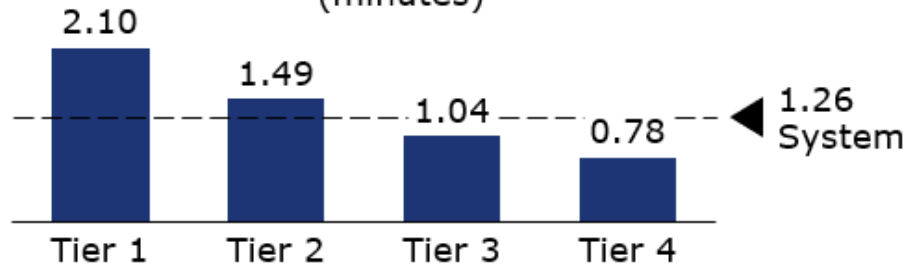
4

Figure 14. Distribution Circuit Reliability Tier Comparison

**Jan to Jul 2023 Tier Customer SAIDI
(minutes)**



**Jan to Jul 2023 Tier Customer SAIFI
(minutes)**



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

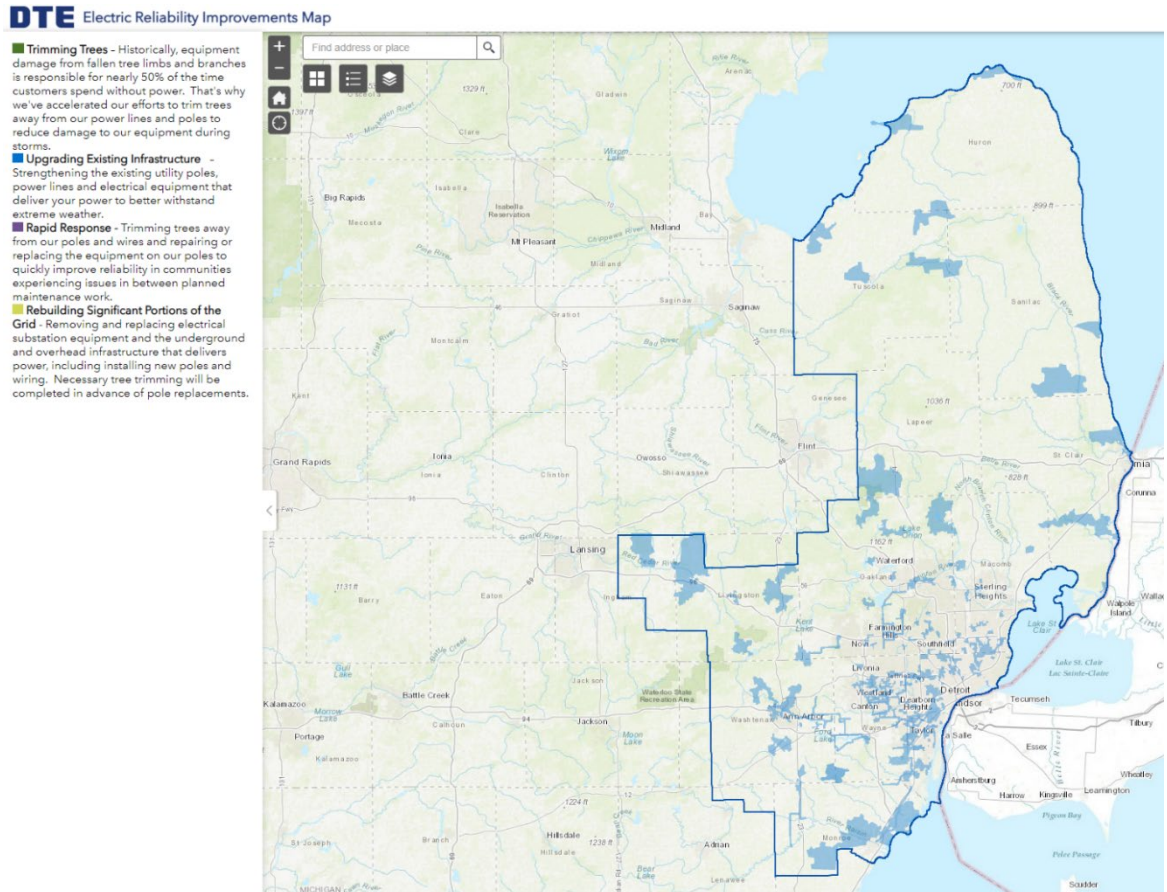
9 **Q64. How can customers stay informed about PTMM work being performed in their**
10 **area?**

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



2

3 **Substation Risk**

4 **Q65. What are Substation Risk projects?**

5 A65. Projects in this category are designed to remediate failures of substations that have
6 already occurred, or to prevent catastrophic substation failures in the future. Because
7 a substation typically supports several circuits, substation catastrophic failure events
8 often impact a large number of customers. The events typically are caused by
9 significant equipment failure such as a transformer or switchgear, fires, or flooding
10 events. In addition to affecting a large amount of customers, they can result in lengthy
11 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



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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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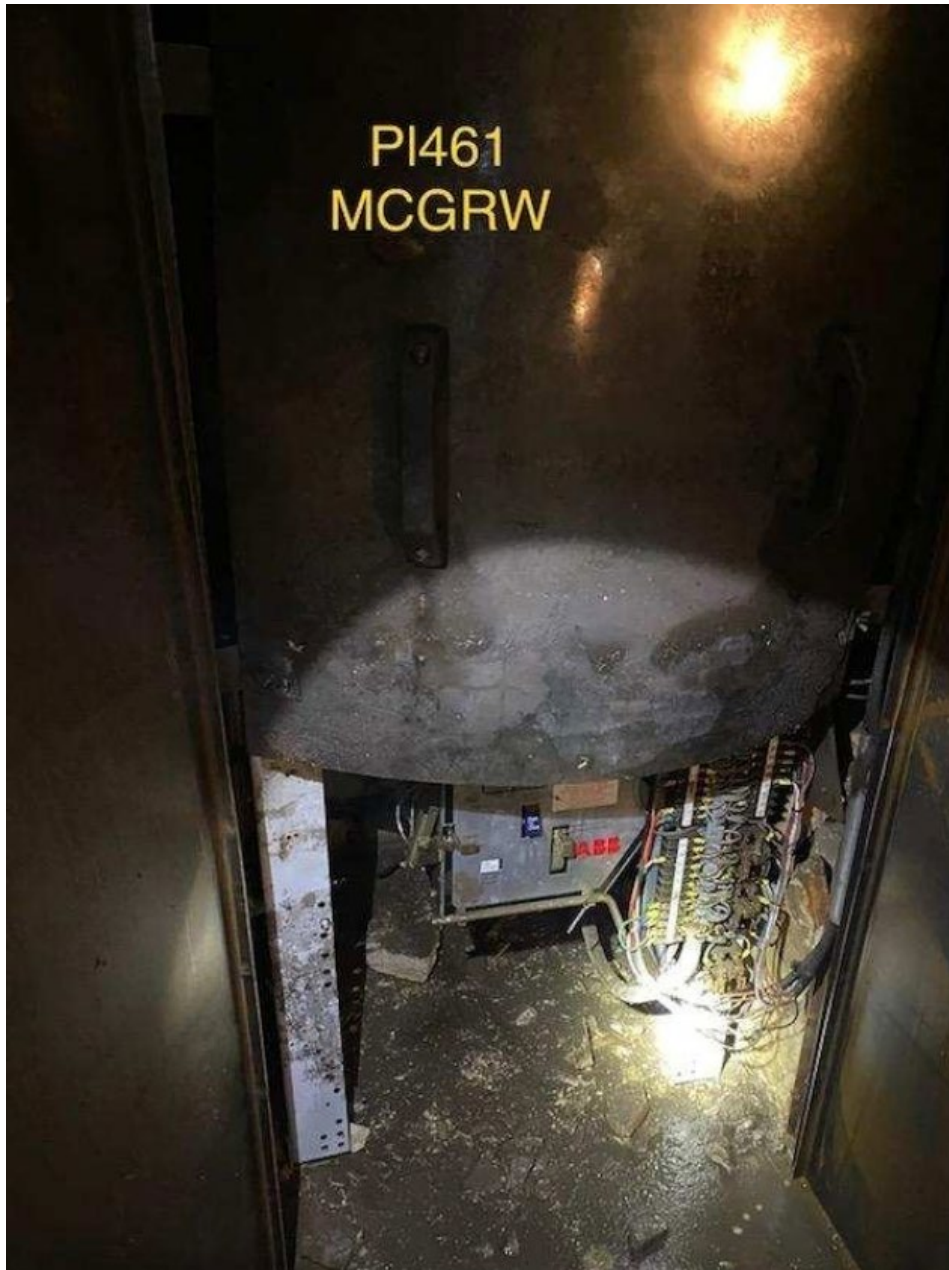
Figure 17. McGraw Substation Flooding – Example 1



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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.

11

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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

Line
No.

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

Line
No.

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.

Line
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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
 - Install (1) 15/20/25 MVA transformer to feed new switchgear
 - Install 6,900 feet of EPR system cable from new switchgear lineup to existing
21 cable poles
 - Decommission and remove the damaged existing switchgear lineup
 - Restore circuits to pre-fire configurations
- 22
23
24

25

More details of this project can be found in Exhibit A-23, Schedule M5.

Line
No.

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

Line
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1 **Q100. What is the scope of the Substation Risk: Savage Switchgear Replacement**
2 **project?**

3 A100. The scope of the Substation Risk: Savage Switchgear Replacement project is to:

- 4 • Remove existing parking area north of existing substation fence –
- 5 approximately 7,800 sq. ft.
- 6 • Extend substation fence approximately 300 feet
- 7 • Perform site preparation and below grade for expanded substation yard
- 8 • Install concrete pads for new switchgear and three (3) 6 MVAR bus capacitor
- 9 banks
- 10 • Install two (2) 9-position 2-high switchgear
- 11 • Install conduit and system cable to existing circuit cables feeding Savage
- 12 circuits and neighboring circuits to enable jumper contingency
- 13 • Extend overhead 770 feet to establish two (2) portable ready locations
- 14 • Install two (2) sets of 3-333KVA regulators
- 15 • Decommission and remove existing 1960's vintage continuous line-up of one
- 16 (1) 16-position switchgear at Savage substation

17

18 This project will be completed in 2024. More details of this project can be found in
19 Exhibit A-23, Schedule M5.

20

21 **Q101. What are the benefits of the Substation Risk: Savage Switchgear Replacement**
22 **project?**

23 A101. The new switchgear will reduce the risk of catastrophic substation failures and
24 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?**

Line
No.

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

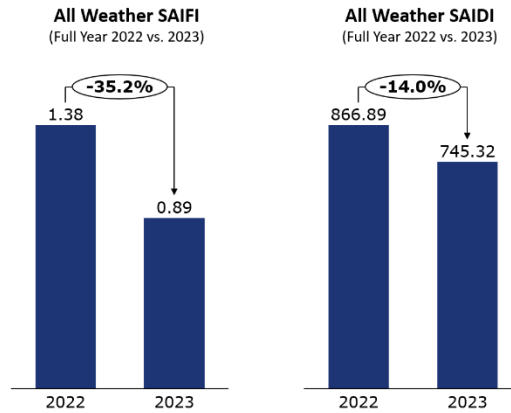
7 **Q115. How do Frequent Outage Programs (CEMI) benefit customers?**

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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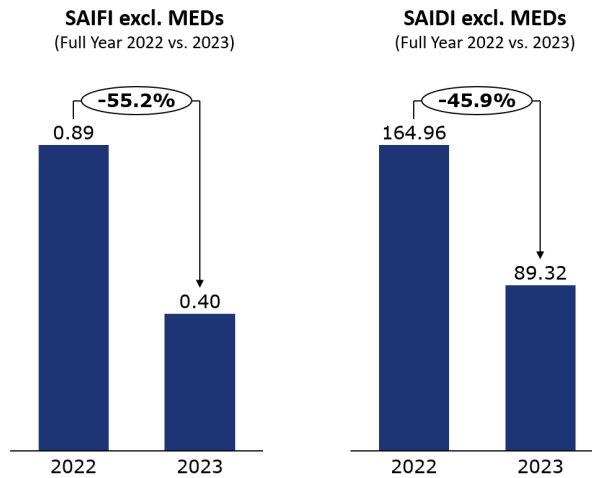
Figure 20. Frequent Outage Programs (CEMI) All Weather



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8

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



9
10
11
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

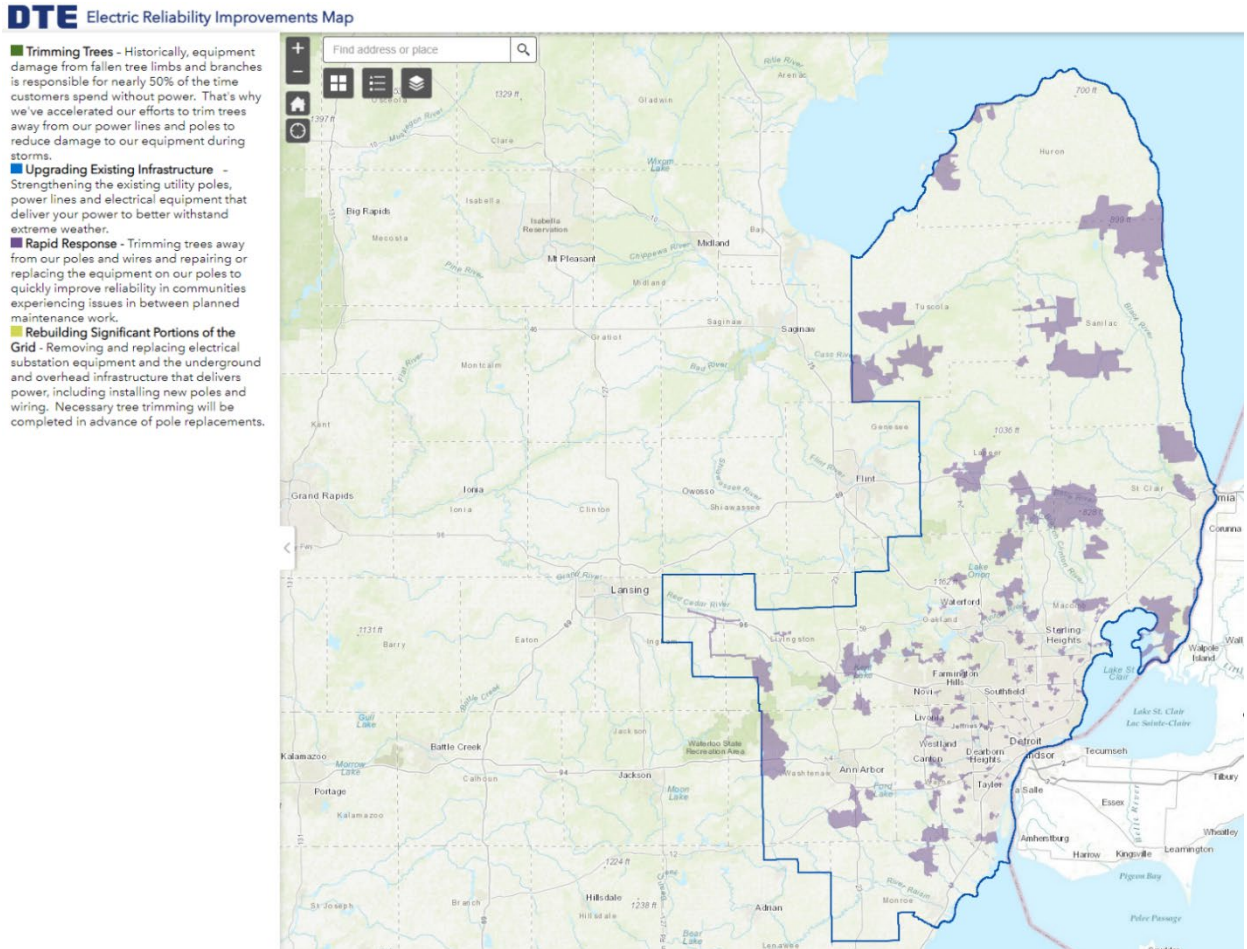
4 **Q116. How can customers stay informed about Customer Excellence work being**
5 **performed in their area?**

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



2

3 **Cable Replacement Program**

4 **Q117. What is Underground (UG) System Cable, and how is it different from**
5 **Underground Residential Distribution (URD) Cable?**

6 A117. System cable is a specific type of cable designed and used for underground distribution
7 and subtransmission on the Company's primary electric system. System Cable consists
8 of large diameter cable surrounded by various types of insulation, and it is installed
9 underground in vaults and ducts that run between manholes (Figure 23 and 24).

10 System cable is used for a different purpose than URD cable. System cable is used to
11 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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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 lead

3 **EPR:** system cable that is insulated with ethylene propylene rubber

4 **VCL:** system cable insulated with varnished cambric

5 **Gas:** system cable that is insulated with nitrogen gas under pressure

6 **XLPE:** system cable that is insulated with cross-linked polyethylene

7 **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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8

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

2

3

Planned replacement of UG system cable allows the Company to proactively target cable at high risk of failure. This allows for a more strategic, and more efficient process to replace large portions of cable in order to reduce the risk of failures and increase redundancies in a given area.

4

5

6

7

8

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

System cable replacement prioritization is based on multiple factors including insulation type, failure history, system impacts, and cable loading. These cables are installed in conduit and spliced together in manholes. When replacing system cable, the Company will also replace failed/collapsed conduit, ducts, and manholes, upgrade substation cable positions, and rebuild cable poles as necessary.

11

12

13

14

15

16

Q120. Was the Cable Replacement Program in the prior rate cases?

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No.

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

24

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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: prioritizing and replacing existing URD cable and replacing live-front UG transformers (described below) with dead-front UG transformers.

7

8

The program prioritizes and replaces URD cable based on multiple factors including number of failures on the circuit, and number of customers affected by those failures, and URD cable type. The program also includes the replacement of live-front transformers with dead-front transformers. Some URD cable is fed from live-front transformers, which is an obsolete design that does not include protective coverings over energized equipment, and therefore poses a potential safety risk to crews in the field while performing operating work once the external transformer covering is removed.

16

17

Single URD cable faults (outages) are typically restored quickly after an UG splicing crew arrives and bypasses the URD failure by back feeding the customers from another source on the URD loop. However, once the customers are restored, there is follow-up work required to locate and repair the URD fault that caused the original outage, and to restore the system to normal operating conditions. This follow-up work is called an

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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

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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

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Figure 27. Live-front UG Transformer



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Figure 28. Dead-front UG Transformer

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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.

6

Q130. Were URD Replacement Program investments supported in prior rate cases?

A130. Yes. The Commission stated in its Order for Case No. U-21297,

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11

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13

“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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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

Q139. How are breakers selected for replacement?

A139. The candidates for breaker replacements are chosen by the Company's equipment engineers who review all breakers on the system. Breakers are prioritized based on the following criteria:

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 flammable; and

11

12

- Breakers that require short inspection cycles compared to the rest of the breakers on our system.

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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.

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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

Line
No.

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

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss.
COUNTY OF WAYNE)

ESTELLA R. BRANSON states that on May 8, 2024, she served a copy of DTE Electric Company's revised Direct Testimony of Witness Morgan Elliott Andahazy in the above captioned matter, via electronic mail upon the persons listed on the attached service list.

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MPSC Case No. U-21534

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