



Jon P. Christinidis
(313) 235-7706
jon.christinidis@dteenergy.com

July 19, 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 and Exhibits of Witnesses, Shannen M. Hartwick, Allen J. Kryscynski, Habeeb J. Maroun and Aaron Willis and revised Direct Testimony of Witnesses, Margaret E. Guillaumin, Michael J. Hatsios, Pankaj Sharma and Theresa M. Uzenski. All corrections to testimony and exhibits are relatively minor and do not increase revenue requirement. Also attached is a Proof of Service.

For ease of reference, also enclosed is a list of corrections identifying the changes. Please feel free to contact me with questions, comments, or concerns.

Very truly yours,

Jon P.
Christinidis

Digitally signed by Jon P.
Christinidis
Date: 2024.07.19 17:10:31 -04'00'

Jon P. Christinidis

JPC/cdm
Attachments

cc: Service List

U-21534 Corrections

Witness	Revision
Guillaumin	1) page 130 line 16 – replaced Crozier with Foley
	1) TMU-21 line 12 2) TMU-29 line 10 3) TMU-30 line 9 4) TMU-31 line 20 5) TMU-35 line 35 6) TMU-36 line 3 and line 11 7) TMU-37 lines 4, 14, 16, 20 8) TMU-38 lines 2, 4, 7, 12, 13 9) TMU-39 lines 1, 2 10) TMU-45 line 13 11) TMU-78 line 11 12) TMU-79 line 12 13) TMU-86 lines 15, 18 14) TMU-87 line 23 15) TMU-88 line 4 (The references to Cooper on pages 21, 30, 31, 35, 37 line 4, 38 lines 12 & 13, and 39 changed to Fix and Hooper. References to Cooper on pages 29, 36, 38 lines 4 & 7, 78, 79 and 86 changed to Fix. References to Cooper on pages 37 lines 14, 16 & 20, 38 line 2, 45, 87 and 88 changed to Hooper.)
Uzenski	16) page TMU-96, line 1 – replaced Crozier with Foley
	1) Exhibit A-12, Schedule B5.4.9 In the Section 3, part (a) (Page 4 of 7), the years mentioned in the project cost should be updated. ~~2021~~ <u>2024</u> ~~2022~~ <u>2025</u> ~~2023~~ <u>2026</u> ~~2024~~ <u>2027</u> 2) Added “Revised” to SMH-4 line 25 and SMH-76 line 18
Hartwick	
	1) Exhibit A-23 - U-21534 Exhibit A-23 M1 - On M1 pg. 6, line 80 and 81 – added footnote to reference project split between U-21297 and U-21534 - Corrected “Distribution Plant – XXX” in header on pages 5-9 from “Distribution Plant – Infrastructure Resilience and Hardening” to correct label - U-21534 Exhibit A-23 M2 - Correct M2 header on all pages - On M2, page 7, Footnote 5/ showed \$25,961, corrected to \$25,543 - U-21534 Exhibit A-23 M3 - On M3 pg. 7, line 2 – added footnote to reference projects combined from U-21297 to U-21534 2) Revised testimony to identify Exhibit A-23 M1 (Revised), A-23 M2 (Revised), A-23 M3 (Revised) throughout.
Krascynski	
Sharma	1) PS-86 line 21

U-21534 Corrections

	2) PS-87 line 14, line 23, line 25 3) PS-88, line 1-5 4) PS-90 line 15 5) PS-91 line 11 6) PS-127 line 11 Revised testimony to update Schedule B5.7.6 and B.5.7.7 references Updated project details on PS-88
Willis	Revised Exhibit A-16, Schedule F3 Page 22 Revised Exhibit A-16, Schedule F9 AW-34 changed rate in table included in Q/A58
Hatsios	MJH-71 line 23, added footnote 1
Maroun	Exhibit A-15, Schedule F1.5 • Page 1 Line 1: Net Production Costs Rev. Req. (Exh A-16 Sch F1.1 Line 31) • Page 1 Line 5: Less Other Energy in PP (WP A16 F1 Page 29 Line 8) • Page 1 Line 11: Capacity Revenue Requirement (Line 7 + Line 9) • Page 1-4 Line 23: Capacity Revenue Requirement (Line 11 * Line 20/100) • Page 1-4 Line 24: Non-Capacity Revenue Requirement (Line 25 less Line 23) • Page 1-4 Line 25: Total Production Revenue Requirement (Exh A-16 Sch F1.1 Line 31) Testimony Added "Revised" to Exhibit A-15, Schedule F1.5 throughout testimony

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

MARGARET E. GUILLAUMIN

DTE ELECTRIC COMPANY
QUALIFICATIONS AND REVISED DIRECT TESTIMONY OF MARGARET E
GUILLAUMIN

Line
No.

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

2 A1. My name is Margaret E. Guillaumin (she/her/hers). My business address is One
3 Energy Plaza, Detroit MI, 48226. I am employed by DTE Electric Company (DTE
4 Electric or Company) as Plant Director in the Energy Supply organization.

5

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

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

8

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

10 A3. My formal education consists of a Bachelor of Science degree in Chemical
11 Engineering from Michigan Technological University. I have also completed
12 several Company sponsored courses and have attended various seminars to further
13 my professional development with DTE Electric.

14

15 **Q4. What work experience do you have?**

16 A4. I began my employment with DTE Electric in July 2003 in the engineering
17 department at River Rouge Power Plant. Throughout my career with DTE Electric
18 I have received various promotions with increasing levels of responsibility. These
19 positions included several engineering roles at the St. Clair Power Plant beginning
20 in November of 2003, Supervisor of Chemical Engineering for DTE Electric's
21 fossil power plants in 2010, Manager of Laboratory and Field Support in 2012, Fuel
22 Supply Manager at St. Clair Power Plant in 2014, and St. Clair Power Plant
23 Maintenance Manager in 2016. In October of 2017, I was promoted to Plant
24 Manager, Greenwood Energy Center, responsible for all day-to-day operation,

Line
No.

1 maintenance, and engineering for the facility. In April 2019, I was given additional
2 responsibilities that included Peakers and Ludington. In this expanded role I added
3 to my responsibilities the operation, maintenance, and engineering of DTE
4 Electric's natural gas and fuel oil Peakers as well as responsibilities for DTE
5 Electric's interest in the Ludington Pumped Storage facility. In April of 2022, I
6 was appointed Plant Manager, Blue Water Energy Center, where I was responsible
7 for transitioning the newly constructed facility through final commissioning
8 activities to commercial operation. Following the commercial operation date, I was
9 responsible for the day-to-day operation, maintenance, and engineering of the
10 facility.

11

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

13 A5. In April 2023, I was promoted to Plant Director, Operations Performance. In this
14 role my responsibilities include periodic outage planning and execution for DTE
15 Electric's fossil power plants, strategic planning and long-term generation strategy,
16 asset maintenance planning, and oversight of the St. Clair, Trenton Channel and
17 River Rouge Power Plants during decommissioning. I also have responsibilities
18 for approving capital projects as a voting member of the Capital Governance Board.
19

Line
No.

1 **Purpose of Testimony**

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

3 A6. The purpose of my testimony is to support the reasonableness and prudence of the
4 operations and maintenance (O&M) and capital expenditures for Energy Supply
5 steam power generation, hydraulic power generation (Ludington), and other power
6 generation for the historical test year ended December 31, 2022, the 24-month
7 bridge period ending December 31, 2024, and the 12-month projected test period
8 ending December 31, 2025. Although Energy Supply currently operates and
9 maintains DTE Electric's fleet of wind and solar assets, costs of these assets are
10 managed in other regulatory proceedings. Therefore, throughout my testimony
11 when I refer to Energy Supply assets, I am referring to the fossil and energy storage
12 assets, including hydraulic storage and Battery Energy Storage Systems (BESS).
13 No part of my testimony includes Energy Supply renewable generation wind and
14 solar assets as they are handled in other regulatory filings as noted above. I also
15 address the following additional topics in my testimony:

- 16 1) I explain forecasted changes affecting generation ratings on a yearly basis for 10
17 years looking forward (2022 through 2032). The changes are associated with
18 projected retirements of current generating assets, the addition of new Energy
19 Supply assets, as well as changes to existing units.
- 20 2) I provide a review of Energy Supply coal-fired and combined cycle unit
21 availability for the most recent five years of actual performance and the next five
22 years projected. In addition to discussing availability, I will also discuss the
23 planned and unplanned outage performance for these same timeframes.

Line
No.

- 1 3) For capital expenditures, I discuss how the Environmental Protection Agency's
2 (EPA) Steam Electric Effluent Limitation Guidelines (ELG) Rule affects
3 required coal-fired generation investments.
- 4 4) I then provide details of the historical 2022 level of expenditures on a plant level
5 basis and provide forecasts of expenditures to be incurred from January 1, 2023
6 through December 31, 2025. This data shows the levels of expenditures related
7 to routine maintenance, environmental compliance requirements, and
8 expenditures related to safety and general reliability that have been and will be
9 made over the timeframes of this case. These discussions on capital
10 expenditures cover the Energy Supply generation and hydraulic plants including
11 the coal-fired and gas-fired steam units, the Ludington pumped storage units, the
12 Blue Water Energy Center combined cycle unit, the peaking units, and new
13 energy storage to be added.
- 14 5) I discuss significant reductions to capital expenditures planned for Monroe Units
15 3 and 4 in light of their accelerated retirement dates.
- 16 6) I support the multiple known and measurable changes in Energy Supply's O&M
17 expenses that will span the timeframe from the 2022 historic test year in this
18 case to the projected test year, ending December 31, 2025. These known and
19 measurable changes include:
- 20 • Retirements of St. Clair and Trenton Channel Power Plants
 - 21 • Blue Water Energy Center commercial operations
 - 22 • Slocum BESS commercial operations
 - 23 • Retirements of Northeast 11-1, River Rouge 11 1-4, Slocum 11 1-5, and St.
24 Clair 12 1-2 peakers and suspension of operation of Fermi 11-3 and Fermi
25 11-4 peakers

Line
No.

- 1 • Corporate memberships excluded from rates.

2

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

4 A7. Yes. I am sponsoring the following exhibits:

5	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
6	A-6	F1	Planned Long Range Generation Changes (Steam,
7			Hydraulic & Other)
8	A-6	F2	Energy Supply Coal and Combined Cycle Unit
9			Performance
10	A-12	B5.1	Projected Capital Expenditures – Steam, Hydraulic,
11			and Other Power Generation
12	A-12	B5.1.1	Commission-requested Monroe FGD Asset
13			Preservation Project Report
14	A-13	C5.1	Projected Operation and Maintenance Expenses –
15			Steam Power Generation
16	A-13	C5.4	Projected Operation and Maintenance Expenses –
17			Hydraulic Power Generation
18	A-13	C5.5	Projected Operation and Maintenance Expenses –
19			Other Power Generation

20

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

22 A8. Yes, they were.

23

24 **Q9. How is your testimony organized?**

25 A9. My testimony consists of the following three (3) parts:

Line
No.

- 1 Part I Energy Supply Plant Capacity and Availability
- 2 Part II Energy Supply Capital Expenditures
- 3 Part III Energy Supply Operation and Maintenance Expenses

4

5 **Part I – Energy Supply Plant Capacity and Availability**6 **Energy Supply Net Summer Installed Capacity**7 **Q10. Can you provide an overview of DTE Electric's Energy Supply assets?**

- 8 A10. As of January 1, 2022, the Company's owned fossil and hydraulic generation based
- 9 on installed summer capacity ratings totaled 9,565 MW and was comprised of:

10 Rated Capacity (Summer) as of 1/1/2022

11	Fossil Steam	6,445 MW
12	Peaking Plant	2,032 MW
13	Pumped Storage	<u>1,088 MW</u>
14	Total Fossil/Hydraulic System	<u>9,565 MW</u>

15

- 16 The Company's 6,445 MWs of fossil steam plant includes coal-fired units that
- 17 provided 5,660 MW of capacity and a gas-fired unit that provided an additional 785
- 18 MW of capacity as shown below:

19

20 Rated Capacity as of 1/1/2022

21	<u>Coal-fired Steam Plants</u>	<u>Net Summer Capability</u>	<u>No. Units</u>
22	Belle River (DTE ownership)	1,034 MW	2
23	Monroe	3,066 MW	4
24	St. Clair	1,065 MW	4
25	Trenton Channel	<u>495 MW</u>	<u>1</u>

Line
No.

1	Total Coal-fired Capacity (steam)	<u>5,660 MW</u>	<u>11</u>

2

3	<u>Gas-fired Steam Plants</u>	<u>Net Summer Capability</u>	<u>No. Units</u>

4	Greenwood	<u>785 MW</u>	<u>1</u>

5	Total Gas-fired Capacity (Steam)	<u>785 MW</u>	<u>1</u>

6

7 The Michigan Public Power Agency (MPPA) is joint owner of Belle River Power
8 Plant and its ownership entitlement is 18.61% (236 MW) of the plant. The MPPA
9 ownership of Belle River Power Plant is not included in the 1,034 MW shown
10 above.

11

12 DTE Electric's peaking plants, along with DTE Electric's ownership share of the
13 Ludington Pumped Storage facility, jointly owned with Consumers Energy, are
14 shown below:

15 Rated Capacity as of 1/1/2022

16	<u>Peaking and Pumped Storage</u>	<u>Net Summer Capability</u>	<u>No. Units</u>

17	Gas/Oil Combustion Turbines	1,904 MW	37
18	(11 locations)		

19	Diesel Generators (10 locations)	<u>128 MW</u>	<u>46</u>

20	Total Peaking Capacity	2,032 MW	83

21

22	Ludington Pumped Storage	<u>1,088 MW</u>	6

23	Total Pumped Storage/Peaking Capacity	<u>3,120 MW</u>	<u>89</u>

24

Line
No.

1 **Q11. Can you provide a summary of Exhibit A-6, Schedule F1 titled “Planned Long**
2 **Range Generation Changes (Steam, Hydraulic, & Other) Years 2022 through**
3 **2032”?**

4 A11. Exhibit A-6, Schedule F1 provides the 2022 actual generation rating changes and a
5 10-year projection of the forecasted changes at Energy Supply units through 2032.
6 Changes are based on the forecasted timing of upcoming unit retirements,
7 development of new Energy Supply assets, and modifications to existing assets.
8 This exhibit does not include new or existing renewable resources.

9

10 **Q12. Can you please explain the yearly generation facility changes shown on Exhibit**
11 **A-6, Schedule F1 for 2022-2032?**

12 A12. The changes for 2022 are shown on lines 1 through 6 of Exhibit A-6 Schedule F1.
13 In 2022, the Company retired St. Clair Units 2, 3, 6, and 7, representing a combined
14 1,065 MW of coal-fired summer-rated capacity. Trenton Channel Unit 9, a coal-
15 fired unit with a summer capacity rating of 495 MW, also retired. The Blue Water
16 Energy Center, a combined cycle gas turbine (CCGT) power plant with a summer-
17 rated capacity of 1,127 MW, commenced commercial operations in June of 2022.
18 The Ludington Unit 3 upgrade for an additional 34 MW of generation capacity was
19 also completed.

20

21 The changes for 2023 are shown on lines 8 and 9 of Exhibit A-6 Schedule F1.
22 Northeast 11–1 peaker (15 MW) experienced significant in-service damage in 2019
23 and was formally retired in 2023. Additionally, the Slocum peakers (14 MW) were
24 retired in 2023 to facilitate the construction of the new Slocum Battery Energy
25 Storage System (BESS).

Line
No.

1

2

The forecasted changes for 2024 are shown on lines 11 through 13 of Exhibit A-6 Schedule F1. The Company plans to retire the River Rouge 11 peakers and the St. Clair 12 peakers, representing 16 MW of summer peaking capacity. Additionally, the Slocum Battery Energy Storage System (BESS), with a rating of 14 MW, is projected to be completed in 2024, replacing the peakers previously located at the site that were retired in 2023.

8

9

10

11

12

The forecasted changes for 2025 are shown on lines 15-16 of Exhibit A-6 Schedule F1. The Company plans to suspend the operations of the Fermi 11-3 and 11-4 peakers, representing 25 MW of summer peaking capacity, and Belle River Unit 1 is projected to convert from coal-fired to natural gas-fired operations.

13

14

15

16

17

The forecasted changes for 2026 are shown on lines 18-19 of Exhibit A-6 Schedule F1. In 2026, the Trenton Channel 220 MW BESS is projected to commence operation and Belle River Unit 2 is projected to convert from coal-fired to natural gas-fired operations.

18

19

No changes are forecasted for 2027 in Exhibit A-6 Schedule F1.

20

21

22

23

24

25

The forecasted changes for 2028 are shown on lines 23-24 of Exhibit A-6 Schedule F1. In 2028, consistent with the final Order dated July 26, 2023, in the Company's 2022 IRP, Case No. U-21193, the Company projects retiring Monroe Units 3 and 4, representing a combined 1,535 MW of coal-fired summer-rated capacity and commencing operation of a 275 MW BESS.

Line
No.

1

2

No changes are forecasted in Exhibit A-6 Schedule F1 from 2029 through 2031.

3

4

The forecasted change for 2032 is shown on line 32 of Exhibit A-6 Schedule F1.

5

In 2032, consistent with the final Order dated July 26, 2023, in the Company's 2022

6

IRP, Case No. U-21193, the Company projects retiring Monroe Units 1 and 2,

7

representing a combined 1,531 MW of coal-fired summer-rated capacity.

8

9

Energy Supply Plant Performance

10

Q13. How is the Company's Energy Supply plant performance monitored and calculated?

11

12

A13. Energy Supply utilizes Equivalent Availability Factor (EAF), Planned Outage Factor (POF), and Random Outage Factor (ROF) to monitor overall unit performance. EAF is equal to 100 minus the POF minus ROF. Equivalent availability is equal to total possible megawatt-weeks minus planned outage megawatt-weeks minus random outage megawatt-weeks (including full and partial derates) divided by total possible megawatt-weeks. Total possible megawatt-weeks are calculated by multiplying the net demonstrated capacity of the unit by the weeks in the time-period (52 weeks per year). Planned outage megawatt-weeks refers to the equivalent number of weeks in the time-period that the unit is not available due to scheduled maintenance multiplied by the capacity that is out of service. Random outage megawatt-weeks is the number of weeks of unit unavailability caused by an outage or derate that is not planned or scheduled, multiplied by the capacity that is out of service.

24

25

Line
No.

1 **Q14. What are the major drivers of unit unavailability?**

2 A14. There are three major drivers of unit unavailability: (1) planned full unit or periodic
3 maintenance outages, (2) unplanned or random unit outages, and (3) derates or
4 partial unit outages which can be planned or unplanned.

5
6 Planned full unit outages and planned derates are those outages for which the
7 Company has developed long range maintenance plans designed to sustain unit
8 performance, install required environmental systems, and proactively address
9 emerging reliability issues. Unplanned unit outages and unplanned derates are
10 those that occur due to either reliability issues common across the industry or
11 unusual events which are unique to a specific DTE Electric plant or unit.

12

13 **Q15. Can you explain the Company's 2022 total Energy Supply plant availability**
14 **performance?**

15 A15. The EAF for Energy Supply steam, hydraulic, and other power generation assets
16 was 74.1% for the 2022 historic period. The 74.1% equivalent availability was the
17 result of a 13.2% ROF and a 12.6% POF. In 2022, Energy Supply assets included
18 Belle River, Blue Water, Greenwood, Monroe, St. Clair, Trenton Channel,
19 Ludington, and peaker power plants. Energy Supply availability for 2022 was
20 reduced by several planned major overhaul maintenance outages completed on
21 Belle River Unit 1, Monroe Unit 2, and multiple peaker units. Less comprehensive
22 planned outages were completed on many units to prepare units for or recover from
23 high peak load summer operations.

24

Line
No.

1 **Q16. What was the equivalent availability specific to the coal-fired and combined**
2 **cycle units within Energy Supply in 2022?**

3 A16. As shown on line 4 of Exhibit A-6, Schedule F2, coal-fired and combined cycle
4 plants had an equivalent availability of 72.7% in 2022 as a result of a 14.7% ROF
5 and a 12.6% POF for those units. Coal-fired plants included the Belle River,
6 Monroe, St. Clair, and Trenton Channel power plants. The Blue Water Energy
7 Center combined cycle plant is also included in the availability metrics.

8

9 **Q17. How does the forecasted future coal-fired and combined cycle unit availability**
10 **compare to the actual historical availability?**

11 A17. As shown in Exhibit A-6, Schedule F2, the average coal-fired and combined cycle
12 unit availability for 2019-2023 was 73.4% while the forecast of average coal-fired
13 and combined cycle unit availability for 2024-2028 is 80.0%. The older and less
14 reliable coal-fired power plants were retired by 2022, resulting in an increase in
15 availability for 2023 and beyond.

16

17 **Part II – Energy Supply Capital Expenditures**

18 **Q18. Can you please provide an overview of your Part II discussion?**

19 A18. Yes. In this section of my testimony, I will discuss the following:

- 20 • Capital Planning Process
- 21 • ELG Rule Compliance
- 22 • 2022-2025 Capital Projects Summary
- 23 • Non-Routine Capital Expenditures
- 24 • Routine Capital Expenditures

Line
No.

- 1 • Reductions to Monroe Unit 3 and 4 Capital Expenditures and Updates to the
- 2 Capital Projects Planned
- 3 • Allowance for Funds Used During Construction (AFUDC) Estimate
- 4 • Removal Costs, Plant in Service and CWIP schedule
- 5

6 **Capital Planning Process**

7 **Q19. Can you explain Energy Supply's capital planning process?**

8 A19. Yes. Capital projects are initiated to support safety, regulatory requirements,
9 environmental compliance, plant-level reliability plans, Original Equipment
10 Manufacturer (OEM) recommendations, or the engineering recommendations of
11 Energy Supply's equipment and system experts. Capital expenditure requests
12 require the development of a plant management approved project request that
13 includes a detailed explanation of the project and an initial estimate of the costs and
14 customer benefits associated with the project. Projects are then further developed
15 including work scope identification and ranking based on customer-centric
16 economic considerations and other important drivers such as safety requirements,
17 environmental regulations, and outage timing opportunities. The planned outage
18 schedule heavily influences capital project timing since many capital projects are
19 implemented during longer duration planned outages to minimize implementation
20 impact on plant availability. During these planned outages, inspections are
21 completed on critical systems to ensure that the outage being executed addresses
22 the work needed to sustain future unit reliability. These inspections can reveal
23 unanticipated damage because many systems cannot be thoroughly inspected or
24 evaluated until they are disassembled during an outage.

25

Line
No.

1 Once capital project requests are fully developed, they are prioritized and presented
2 for management review and approval. The review process focuses on ensuring that
3 the projects utilize the best solution to address the issue at hand and represent the
4 most cost-effective method for accomplishing the proposed work. Projects are
5 approved if they are required to meet safety requirements and/or environmental
6 compliance, are justified by an economic evaluation or represent normal/routine
7 plant component replacements required for continued plant operations that are
8 capitalized per authorized accounting policy.

9
10 In summary, the capital spending and approval process is designed to identify the
11 optimal allocation of capital resources to meet safety requirements and
12 environmental compliance while maintaining overall reliability performance and
13 minimizing costs.

14

15 **Q20. What do you mean by projects being justified by economic evaluation?**

16 A20. The prioritization of economic projects is based on an internal rate of return (IRR)
17 analysis performed comparing the costs of implementing the new project to its
18 customer benefits. Included in the analysis are projected capital expenditures,
19 future avoided outages, heat rate (efficiency), and fuel blending capabilities. Future
20 avoided plant outage impacts include the value of avoiding events such as boiler
21 tube failures, condenser or feedwater heater leaks, and turbine blade failures. The
22 IRR of the project is based on the anticipated O&M, capital expenditures, and
23 energy and capacity market value of the unit's operations with and without the
24 project being implemented over its useful life.

25

Line
No.

1 **Q21. What would be the consequences of not completing the capital projects**
2 **requested in the instant case?**

3 A21. Failure to complete the approved capital projects described in this case could
4 negatively affect plant reliability, environmental compliance, customer
5 affordability, and/or safety.

6
7 **Q22. Can you explain the governance process for approval of Energy Supply's**
8 **capital projects?**

9 A22. The capital governance process includes the documentation of project assumptions,
10 calculation of costs and customer benefits, and a rigorous internal review. Projects
11 costing less than \$250,000 are approved by plant management, utilizing a project
12 appropriation form, within a budget established based on historic plant
13 expenditures. These projects generally do not require engineering and often reflect
14 replacement-in-kind.

15
16 Projects that cost greater than \$250,000 but less than \$10 million and/or projects
17 that require engineering are approved by the Energy Supply Capital Governance
18 Board (CGB) which consists of plant directors, the Director of Engineering, and
19 the Vice President of Energy Supply. A Project Approval Team (PAT) form is
20 utilized to record CGB approvals.

21
22 Projects greater than \$10 million require senior corporate executive approval, while
23 projects greater than \$50 million require approval by the Finance Committee of
24 DTE Energy's Board of Directors. All projects greater than \$10 million must be

Line
No.

1 authorized by a Capital Appropriations Request Form (CARF) approved by the
2 appropriate Company representatives.

3

4 **ELG Rule Compliance**

5 **Q23. How does the EPA's Steam Electric ELG Rule affect the Company?**

6 A23. As discussed in more detail by Company Witness Lee, the EPA's ELG Rule
7 regulates how electric utilities must manage certain wastewaters. On October 13,
8 2020, the EPA finalized the ELG Reconsideration Rule which revised some
9 requirements from the 2015 ELG Rule and added time-based options for complying
10 with the updated requirements for Bottom Ash Transport Water (BATW) and Flue
11 Gas Desulfurization (FGD) wastewater. Subsequently, on May 30, 2023, the EPA
12 published a Direct Final Rule which extended the deadline for units to opt-in to the
13 cessation of coal compliance subcategory from the 2020 ELG Rule, which allows
14 for operation of a unit until end of 2028 in lieu of installing a technology-based
15 compliance option. Bottom ash transport water cannot be discharged to the
16 environment after December 31, 2025, from a coal-fired power plant unless the
17 plant committed to ceasing coal-fired operations by the end of 2028, by opting into
18 the cessation of coal compliance subcategory. Regarding FGD wastewater streams,
19 plants with FGD systems can comply with one set of limits by December 31, 2025
20 or comply with a set of more stringent limits by December 31, 2028 if the plant
21 plans to continue coal-fired operations past 2028. Fly ash transport water (FATW)
22 discharge limitations were not altered in the Reconsideration Rule and Direct Final
23 Rule and continued to have a December 31, 2023 compliance date.

24

25 **Q24. Did the Company submit any filings under the ELG Reconsideration Rule?**

Line
No.

1 A24. Yes. To utilize the ELG Reconsideration Rule's time-based options, companies
2 were required to submit a Notice of Planned Participation (NOPP) to their state
3 permitting agency. The Company filed NOPPs for Monroe and Belle River Power
4 Plants. Please refer to additional testimony for Monroe and Belle River Power
5 Plants below, as well as Company Witness Lee's testimony, for more information.

6

7 **Q25. Has the Company made a formal commitment regarding how Belle River**
8 **Power Plant will comply with ELG Rules?**

9 A25. Yes. The NOPP that DTE Electric filed with the Michigan Department of
10 Environment, Great Lakes, and Energy (EGLE) on October 13, 2021 indicated a
11 commitment to cease coal-fired operations at Belle River Power Plant. The fuel
12 conversion at Belle River qualifies for ELG compliance as it results in ceasing coal-
13 fired operations. This decision allows the Company to avoid installing new ELG-
14 compliant bottom ash transport technology by the end of 2025.

15

16 **Q26. How did the Company comply with the FATW-portion of the ELG Rule at**
17 **Monroe Power Plant?**

18 A26. The FATW-portion of the ELG Rule required companies to cease water discharges
19 related to the transport of fly ash by the end of 2023. A project to install piping and
20 silos and other infrastructure for the dry transport of fly ash from Monroe Power
21 Plant boilers to a permitted storage area was completed in 2023, meeting the
22 required compliance date.

23

24 **Q27. How will the Company comply with the BATW-portion of the ELG Rule at**
25 **Monroe Power Plant?**

Line
No.

1 A27. Monroe Units 1 and 2 are required to comply with the BATW-portion of the ELG
2 Rule by the end of 2025. The Company plans to terminate the use of water for
3 bottom ash transport on Monroe Units 1 and 2. In place of water conveyance, a dry
4 drag chain conveyor system will be installed. This project was approved by the
5 Company in 2022 and is fully underway and will meet the required compliance
6 date.

7

8 Monroe Units 3 and 4 will not be required to terminate the use of water for bottom
9 ash transport by the end of 2025. The Company submitted an NOPP for BATW on
10 Monroe Units 3 and 4 and will comply with the BATW-portion of the ELG Rule
11 by retiring Monroe Units 3 and 4 by the end of 2028, thereby eliminating their
12 production of BATW and the need and expense to install a new transport system.

13

14 **Q28. How does the Company plan to comply with the FGD wastewater-portion of**
15 **the ELG Rule at Monroe Power Plant?**

16 A28. Monroe Power Plant is required to comply with the FGD wastewater-portion of the
17 ELG Rule by the end of 2025, unless the Company participates in the Voluntary
18 Incentives Program (VIP) contained in the 2020 ELG Rule. The VIP allows
19 compliance to be achieved by the end of 2028 if the Company agrees to meet more
20 stringent FGD wastewater effluent limitations. The Company filed a VIP NOPP in
21 October 2021, allowing it to evaluate alternative compliance technologies for
22 Monroe Units 1 and 2.

23

24 The retirements of Monroe Units 3 and 4 in 2028 will eliminate the production of
25 FGD wastewater on those units, thereby eliminating the need and expense to install

Line
No.

1 FGD wastewater treatment systems on those units. Consequently, the Company
2 filed a cessation of coal compliance subcategory NOPP in April 2023.

3

4 **2022-2025 Capital Projects Summary**

5 **Q29. Can you provide a high-level discussion of the routine and non-routine capital**
6 **expenditures being made by the Company for steam, hydraulic, and other**
7 **power generation during the historical year 2022, the bridge period and the**
8 **projected test period ending December 31, 2025?**

9 A29. The Company's Energy Supply group makes routine ongoing expenditures across
10 its existing generation fleet (steam, hydraulic, and other power generation) to
11 maintain safe, environmentally compliant, reliable, and efficient operations. Most
12 of these routine expenditures are primarily for Monroe and Belle River Power Plant
13 projects. To a lesser degree, there are routine capital expenditures for the remaining
14 assets including Blue Water Energy Center, Greenwood Energy Center, and
15 peakers.

16

17 Non-routine capital project expenditures are driven by steam power generation unit
18 upgrades with a heavy focus on environmentally mandated work at Monroe Power
19 Plant. Other major non-routine capital projects included in the instant case are
20 related to decommissioning and environmental remediation projects at retired coal
21 plants, construction of Blue Water Energy Center, and new utility scale energy
22 storage systems.

23

24 **Q30. Can you explain Exhibit A-12, Schedule B5.1 entitled, "Projected Capital**
25 **Expenditures Steam, Hydraulic and Other Power Generation" in more detail?**

Line
No.

1 A30. Exhibit A-12, Schedule B5.1 is a 9-page exhibit. Page 1 summarizes both “routine”
2 and “non-routine” capital expenditures for 2022 (the historical actual test period)
3 through the bridge period and the 12 months ending December 31, 2025 (the
4 projected test period) for Steam Power Generation, Hydraulic Power Generation
5 (Ludington Pumped Storage), and Other Power Generation. Page 2 provides
6 additional detail for major non-routine capital expenditures for Steam, Hydraulic,
7 and Other Power Generation. Page 3 summarizes routine Steam, Hydraulic, and
8 Other Power Generation capital expenditures by plant site and major category.
9 Pages 4 through 7 provide additional detail for the routine maintenance projects
10 with expenditures of greater than \$1 million for 2022 through December 31, 2025.
11 Page 8 summarizes AFUDC included in the routine and non-routine capital
12 expenditures. Finally, page 9 summarizes the plant in service and CWIP
13 assumptions included in the capital forecast.

14
15 **Q31. Can you provide additional details concerning Exhibit A-12, Schedule B5.1,**
16 **page 1 of 9 entitled, “Projected Capital Expenditures Steam, Hydraulic, and**
17 **Other Power Generation”?**

18 A31. Yes. Line 2, Routine Steam Power Generation, includes capital expenditures
19 necessary to operate and maintain Energy Supply’s fossil steam power plant sites.
20 Included are projects related to safety, boiler and turbine work, cables and controls,
21 balance of plant projects and maintenance of environmental control systems.
22 Safety expenditures include the capital projects necessary to maintain a safe work
23 environment and meet applicable safety regulations and standards. Boiler and
24 turbine work include the capital expenditures intended to maintain boiler or turbine
25 operations, replace unreliable systems or equipment, support heat rate (efficiency),

Line
No.

1 and/or address operating and maintenance problems related to the boiler and turbine
2 systems. Examples of these projects include replacement of worn or damaged
3 turbine blades, air heater baskets, and boiler tube sections such as waterwalls,
4 reheaters, superheaters, and economizers. Cables and controls expenditures include
5 the capital expenditures to replace or improve distributed control systems, large
6 power cables, main unit transformers, and electrical switchgear. The balance of
7 plant area expenditures includes the capital associated with mobile equipment,
8 station air compressors, general service water systems, fuel handling equipment and
9 systems, and plant vehicles and computers. Routine environmental expenditures
10 include the capital necessary to maintain operations of existing environmental
11 control and monitoring equipment. An example of routine environmental
12 expenditures is the ongoing replacement of the Selective Catalytic Reduction
13 (SCR) catalyst beds installed at Monroe Power Plant to comply with nitrogen
14 oxides (NOx) emissions limits. These routine environmental capital expenditures
15 associated with existing environmental systems differ from the non-routine
16 environmental capital expenditures required to install any future new
17 environmental systems.

18

19 Line 3, Non-Routine Steam Power, includes capital expenditures related to
20 environmental compliance projects, site decommissioning, environmental
21 remediation, and required equipment modifications related to retired power
22 generation assets, as well as other plant level projects such as physical and cyber
23 security at generation sites.

Line
No.

1 Line 6, Routine Hydraulic Power Generation, includes the Company's share of the
2 routine capital expenditures necessary to operate and maintain the Ludington
3 Pumped Storage facility.

4

5 Line 7, Non-Routine Hydraulic Production Plant, includes the Company's share of
6 the capital expenditures related to the efficiency upgrade project at the Ludington
7 Pumped Storage facility. This multi-year project included installation of new
8 higher efficiency hydraulic turbines, main unit transformers, and upgraded
9 generators on all six units.

10

11 Line 10, Routine Other Power Generation, includes capital expenditures related to
12 maintaining peaker and combined cycle operations, including routine overhauls.

13

14 Line 11, Non-Routine Other Power Generation, primarily includes capital
15 expenditures related to the development and construction of the Blue Water Energy
16 Center (a 1,127 MW (summer-rated capacity) CCGT plant) and the development
17 of new BESSs.

18

19 Lines 15 and 16 include Monroe regulatory asset routine and non-routine capital
20 expenditures. Consistent with the Order in the Company's 2022 IRP filing, Case
21 No. U-21193, the Company is including 2025 and all future Monroe capital
22 expenditures in the regulatory asset.

Line
No.

1 **Non-Routine Capital Expenditures**

2 **Q32. Can you summarize Exhibit A-12, Schedule B5.1, page 2 of 9 entitled,**
3 **“Projected Capital Expenditures Steam, Hydraulic, and Other Power**
4 **Generation – Non-Routine”?**

5 A32. Page 2 of Exhibit A-12, Schedule B5.1 provides project level detail for non-routine
6 capital expenditures completed and planned for Steam Production, Hydraulic, and
7 Other Power Generation from 2022 through December 31, 2025.

8
9 **Q33. Can you explain line 2 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

10 A33. Line 2 (Belle River Fuel Conversion) represents a project to convert the Belle River
11 Power Plant’s fuel source from coal to natural gas, consistent with the Company’s
12 approved 2022 IRP in Case No U-21193. The Order in Case No. U-21193 also
13 included preapproval of the Belle River Fuel Conversion project.

14
15 In 2022, \$1.4 million was spent on this project. The Company approved the funding
16 and execution of this project in September 2022. An Owner’s Engineer (OE) firm
17 was contracted to provide engineering support, bid specification support, and
18 technical review for the duration of the project. A request for proposal (RFP) to
19 develop project scope, schematic design, and budgetary pricing was issued to
20 support 2025 and 2026 gas conversions on Belle River Units 1 and 2, respectively.

21
22 For 2023, the project planned expenditures are \$2.2 million and includes selection
23 of an engineering, procurement, and construction (EPC) contractor for the fuel
24 conversion of Belle River Units 1 and 2 that can meet the planned timelines. Work
25 includes the development of an EPC bid specification that included the engineering

Line
No.

1 design, material procurement, and installation of the natural gas systems for both
2 units. Material procurement includes components for burner and ignitor
3 modifications, ductwork modifications, air heater modifications, low and high-
4 pressure gas reducing skids, a gas detection monitoring system, gas yard
5 equipment, and components for associated electrical and controls upgrades.
6 Additionally, a limited notice to proceed was issued in December 2023 to the
7 selected EPC contractor.

8
9 In 2024, \$39.3 million is projected to continue material procurement and complete
10 detailed design, including erection arrangements and the controls upgrade
11 requirements.

12
13 In 2025, \$41.8 million is projected to be spent on this project. 2025 work scope
14 includes installation of a natural gas pipeline from a nearby high-pressure interstate
15 pipeline to the power plant, constructing the in-plant gas piping system, and
16 controls systems for Belle River Unit 1, and retrofitting Belle River Unit 1 with
17 natural gas burners in its fall periodic outage.

18
19 In 2026, which is beyond the projected test year in the instant case, the in-plant gas
20 piping system and controls systems for Belle River Unit 2 will be constructed and
21 the unit will be retrofitted with natural gas burners in its fall periodic outage.

22

23 **Q34. Can you explain line 3 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

24 A34. Line 3 (Belle River Bottom Ash Basin Modification (CCR)) represents a project to
25 retrofit the north and south bottom ash basins at Belle River Power Plant with CCR

Line
No.

1 Rule-compliant liner systems and to close the diversion basin by removal of all ash
2 from the basin. The removed ash was transported to and disposed of at the Range
3 Road Landfill. The Company spent \$60 thousand in 2022 for project engineering.
4 Project construction was initiated and was completed in 2023 for \$3.4 million. This
5 project was required by the EPA's CCR Rule as discussed in Witness Lee's
6 testimony.

7

8 **Q35. Can you explain line 4 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

9 A35. Line 4 (Monroe Dry Fly Ash Conversion (ELG)) represents a project to convert the
10 existing wet fly ash handling system at Monroe Power Plant to a dry system on all
11 four Monroe Power Plant units. The EPA's fly ash ELG rule promulgated in 2015
12 required all liquid discharges to the environment from fly ash transport systems to
13 cease by December 31, 2023. Conversion to a dry fly ash handling system required
14 installation of new equipment to pneumatically transport ash from each generating
15 unit's precipitator to new storage silos. The project included installation of
16 transport piping from the unit precipitator hoppers to the local unit silos and
17 installation of transport piping from the local unit silos to two central storage silos.
18 Blowers were installed to convey the fly ash to the respective ash silos. The
19 Company approved the funding and execution of this project in March 2020.

20

21 In 2022, \$20.0 million was spent to engineer and construct a local ash silo for each
22 of the four units, receive all long lead material, and complete the silos and
23 interconnection piping systems for the four Monroe units. The equipment tie-in was
24 completed on Monroe Unit 2 during an outage that ended in December 2022.

25

Line
No.

1 In 2023, \$20.8 million was spent to tie-in new fly ash handling systems on Monroe
2 Units 1 and 3 in spring 2023 and Monroe Unit 4 in fall 2023.

3

4 In 2024, \$1.2 million is projected for final site work, project demobilization, and
5 performance testing. As required under the ELG Rule, the new fly ash handling
6 systems were operational by the end of 2023.

7

8 **Q36. Can you explain lines 5 and 47 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

9 A36. Lines 5 and 47 (Monroe Bottom Ash Conversion (ELG)) represent a project to
10 install an ELG-compliant bottom ash transport system that must be completed at
11 Monroe Power Plant Units 1 and 2 by the December 31, 2025 EPA deadline. The
12 Company approved the funding and full execution of this project in December
13 2022. The project scope includes removal of the wet bottom ash collection systems
14 and major modifications to the boiler bottom hopper areas to permit installation of
15 dry drag chain conveyor systems for ash removal. Project scope also includes the
16 integration of the economizer ash handling systems into the dry fly ash handling
17 systems utilizing dry flight conveyors. Once removed from the individual boilers,
18 the bottom ash is moved outside the plant wall and into bunkers that function as the
19 feed point for loading trucks with bottom ash to be sold or disposed of off-site.

20

21 The Company spent \$4.2 million in 2022 to engineer ELG-compliant systems and
22 procure long-lead materials.

23

24 For 2023, \$11.4 million was projected to be spent to perform final engineering, bid
25 project construction, and continue material procurement in support of the Unit 1

Line
No.

1 and Unit 2 new bottom ash transport systems. In the Company's previous electric
2 rate case, Case No. U-21297, the forecast had included the completion of
3 engineering, bidding and award of project construction, and tie-in of new systems
4 on Monroe Unit 3 and Unit 4 for converting the economizer ash transport systems.
5 This work scope was not executed because the EPA ELG Direct Final Rule issued
6 in May 2023 allowed Monroe Unit 3 and Unit 4 to retire by the end of 2028 without
7 installing the new bottom ash handling systems otherwise required under the ELG
8 Rule.

9
10 In 2024, \$26.1 million is projected to award project construction and complete the
11 installation of a common Unit 1-2 bunker and drag chain conveyor system. The
12 new bottom ash handling system tie-in outage and connection to the new dry
13 economizer ash transport system on Monroe Unit 2 will also be done in a fall 2024
14 outage.

15
16 In 2025, \$23.1 million is projected to be spent for the new bottom ash handling
17 systems that will be connected to Monroe Unit 1 in the fall of that year.
18 Additionally, the new economizer ash transport system will be installed on Monroe
19 Unit 1 in the fall. Included in this \$23.1 million is \$4.3 million of project costs that
20 were prudently incurred prior to issuance of the May 30, 2023 EPA Direct Final
21 Rule which extended the deadline for plants to opt-in to the 2028 early retirement
22 provision promulgated in the 2020 ELG regulation. In the Company's previous
23 electric rate case, Case No. U-21297, Staff Witness Kindschy acknowledged that
24 the Company "may have incurred some capital expenditures in 2023 for this project
25 prior to being able to opt-in to a 2028 retirement, and those capital expenditures can

Line
No.

1 be included in the Company's next rate case for review and recovery."¹ The \$4.3
2 million that was prudently incurred prior to issuance of the Direct Final Rule is
3 included in line 5 of Exhibit A-12, Schedule B5.1, page 2 of 9 as a credit to the
4 conversion project and is included in line 47 of Exhibit A-12, Schedule B5.1, page
5 2 of 9 for recovery through the regulatory asset. In accordance with the Company's
6 2022 IRP Order, recovery of Monroe Power Plant capital investments on this
7 project made after January 1, 2025 will be processed through a regulatory asset,
8 shown on line 47 of Exhibit A-12, Schedule B5.1, page 2 of 9.

9

10 As required under the ELG Rule, all the new dry bottom ash and economizer ash
11 handling systems on Monroe Units 1 and 2 will be operational by the end of 2025.
12 This work is required to maintain environmental compliance and allow the units to
13 continue to provide power for customer benefit.

14

15 **Q37. Can you explain lines 6 and 48 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

16 A37. Lines 6 and 48 (Monroe FGD Wastewater (ELG)) represent a project to develop an
17 ELG-compliant flue gas desulfurization (FGD) wastewater discharge treatment
18 system at Monroe Power Plant. The Company spent \$0.3 million in 2022 to
19 perform technology evaluations and initial site engineering scoping efforts. In
20 2023, \$0.5 million of expenditures were projected to evaluate compliance
21 technologies for Monroe Units 1 and 2 and this evaluation will continue in 2024
22 and 2025 for \$1.0 million each year. In accordance with the Company's 2022 IRP
23 Order, recovery of Monroe Power Plant investments on this project made after

¹ Case No. U-21297 Kindschy, 7T 4512

Line
No.

1 January 1, 2025 will be processed through a regulatory asset, shown on line 48 of
2 Exhibit A-12, Schedule B5.1, page 2 of 9.

3

4 **Q38. Can you explain line 7 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

5 A38. Line 7 (Monroe Dry Fly Ash Haul Road) represents a project that constructed a
6 new asphalt road from Waters Edge Drive to the Monroe Power Plant vertical
7 extension landfill. The Company spent \$0.3 million to complete the new road in
8 the first quarter of 2022. The new road reduces heavy truck traffic on public roads
9 traversing residential areas and additionally minimizes related fugitive dust
10 emissions.

11

12 **Q39. Can you explain lines 8-13 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

13 A39. Lines 8-13 (Site Security Projects and NERC Compliance Projects) represent
14 projects required to improve power plant security. General site access security
15 improvements as well as security enhancements for critical equipment are being
16 implemented to mitigate security threats. In addition to physical security, North
17 American Electric Reliability Corporation Critical Infrastructure Protection
18 (NERC-CIP) compliance requires the Company to protect its cyber assets to
19 minimize the risks to the electrical grid. The need for increased physical and cyber
20 security for our electric assets are increasingly evident as seen in recent events at
21 other utilities. NERC-CIP-003 was originally issued in 2010 and has undergone
22 updates in 2014, 2016, and 2020 to include additional standards the Company needs
23 to meet. NERC-CIP-003 requires the Company to control and track physical access
24 to any NERC sensitive site. In order to be compliant with the CIP standard, the
25 Company reviewed physical access at all power plants and developed projects to

Line
No.

1 mitigate risks. Risks to the bulk electric system continue to increase. As a result,
2 some project information, most noticeably site locations, must be tightly restricted
3 to maintain the integrity of these measures. Project major work efforts, timelines,
4 and expenditures are being provided as discussed below.

- 5 • Line 8 (Site Security Project 11504) represents a project to install a security
6 station at a power plant site. The work includes modifying utilities, adding
7 road lanes and signage, and installing security barriers and a security
8 building. In 2022, \$2.8 million was spent to complete engineering, procure
9 long lead materials, and bid and award construction. For 2023, \$2.2 million
10 was projected to be spent to continue material procurement and initiate
11 construction including relocation of transmission lines and Company
12 primary utility lines from the power plant site to an adjacent right-of-way.
13 In 2024, \$5.4 million is the projected expenditures required to complete
14 construction of project.

- 15 • Line 9 (Site Security Project 18700) represents a completed project that
16 installed badge card readers at a power plant in January 2023. In 2022, \$15
17 thousand was spent on door locks. In 2023, \$52 thousand was spent on
18 procuring badge readers and installation of the equipment to complete the
19 project.

- 20 • Line 10 (Site Security Project 18906) represents a project to install a site
21 entrance security building at a power plant. The Company spent \$1
22 thousand in 2022 and planned to spend \$0.8 million in 2023 for engineering,
23 design, and procurement of the security building and to begin concrete
24 foundation construction. The Company plans to spend \$0.3 million in 2024

Line
No.

1 to complete the installation of the security building and tie-in of building
2 utilities.

3 • Line 11 (Site Security Project 20061) represents a project to install a site
4 security fence at a satellite property supporting power plant operations.
5 Prior to the installation of the fence, there was no physical barrier to prevent
6 trespassers from accessing the property. The Company spent \$0.2 million
7 in 2023 to complete this work.

8 • Line 12 (NERC Compliance Project 18885) represents a project to install a
9 NERC-compliant perimeter fence at a power plant for expenditures of \$0.6
10 million in 2022 and \$1.1 million in 2023. The need for the new fence was
11 triggered by the recent retirement and decommissioning of a power plant
12 which was previously providing site security within its protected area.

13 • Line 13 (NERC Compliance Project 19895) represents a project that
14 restored a NERC-compliant perimeter fence in 2023 for \$7 thousand.

15

16 **Q40. Can you explain lines 14-17 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

17 A40. Lines 14-17 (Sibley Quarry Landfill Modification (CCR), Sibley Quarry Conveyor
18 Installation (CCR), Sibley Quarry Infrastructure Modification (CCR), and Sibley
19 Quarry Landfill Dewatering and Discharging Line) includes costs associated with
20 site improvements required to allow safe and efficient acceptance of the significant
21 quantities of coal combustion residuals (CCR) waste material that are being
22 removed from Monroe Power Plant. Approximately 1 million cubic yards of
23 bottom ash from the Monroe Power Plant inactive bottom ash basin is being
24 transported to Sibley Quarry to meet the EPA's CCR regulation. The improved

Line
No.

- 1 system will continue to be used after the completion of the Monroe Bottom Ash
2 Basin Closure (CCR) project for continuing waste disposal activities.
- 3 • Line 14 (Sibley Quarry Landfill Modification (CCR)) – The Company spent
4 \$5.6 million in 2022 to install a drain piping shaft (chimney drain) and
5 create a new landfill operation fill plan. In 2023, \$1.8 million was spent to
6 complete the project by installing a filtration system around the drain piping
7 shaft and to relocate equipment to the current ash waste elevation.
8 Approximately 23,000 cubic yards of material had to be moved so that stone
9 could be placed for the chimney drain. Approximately 125,000 cubic yards
10 of course aggregate limestone and approximately 40,000 cubic yards of
11 crushed limestone was installed for the 18-ft diameter, 105-ft high chimney
12 drain construction. The Company plans to spend \$8 thousand in 2024 for
13 final project closeout including final paperwork and as-built drawings. This
14 project is required to allow continuing acceptance of bottom ash removed
15 due to the closure of the Monroe bottom ash basin while continuing
16 compliance with the provisions of Part 115, Solid Waste Management, of
17 the Natural Resources and Environmental Protection Act, 1994 PA 451, as
18 amended, and its Solid Waste Disposal Area Operating License number
19 9602.
 - 20 • Line 15 (Sibley Quarry Conveyor Installation (CCR)) – The Company spent
21 \$0.4 million in 2022 to complete engineering and installation of a new
22 conveyor system that transports material from the designated truck
23 unloading area to the bottom of the quarry.
 - 24 • Line 16 (Sibley Quarry Infrastructure Modification (CCR)) – The Company
25 spent \$1.8 million in 2022 to engineer and construct a road, truck unloading

Line
No.

1 pad, and temporary office to support the increasing levels of activity the site
2 will experience in support of the Monroe ash removal tasks supporting CCR
3 and ELG requirements. The Company spent \$9 thousand in 2023 for final
4 project close out costs.

- 5 • Line 17 (Sibley Quarry Landfill Dewatering and Discharging Line) – The
6 Company spent \$1.8 million in 2022 to replace a portion of the piping that
7 transports accumulated ground water out of the Sibley Quarry to the Detroit
8 River in compliance with its National Pollutant Discharge Elimination
9 System (NPDES) permit. The replaced portion of pipe is approximately
10 4,400 linear feet. The previous discharge piping was failing and required
11 replacement. The Company spent \$32 thousand in 2023 for project closeout.

12

13 **Q41. Can you explain line 20 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

14 A41. Line 20 (Monroe Bottom Ash Basin Closure (CCR)) represents a project to remove
15 all bottom ash from the inactive bottom ash basin at Monroe Power Plant to meet
16 the EPA's CCR regulation. This project includes the removal of approximately 1
17 million cubic yards, equal to over 1 million tons, of bottom ash from the Monroe
18 inactive bottom ash basin and its transportation to Sibley Quarry. This project
19 typically utilizes up to 10 trucks per day, each able to transport approximately 40
20 tons of bottom ash per load. Each truck averages five loads per day for the 46-mile
21 roundtrip commute between Monroe Power Plant and Sibley Quarry. The trucks
22 only operate from March to November because cold winter weather is not suitable
23 for bottom ash material dewatering required for transport.

24

Line
No.

1 The project received Company approval in December 2019. The final EPA CCR
2 Rule requires closure to be initiated as soon as technically feasible, but no later than
3 April 11, 2021 and be completed within five years. Closure was initiated on
4 October 21, 2020.

5

6 In 2022, \$15.4 million was spent to complete the transport of 0.6 million cubic
7 yards of bottom ash from Monroe Power Plant that began in 2021.

8

9 For 2023, \$14.6 million was projected to be spent to continue bottom ash material
10 removal from the Monroe basin and its transportation to Sibley Quarry.

11

12 In 2024, \$11.9 million is projected to be spent to complete the bottom ash removal
13 and transportation. The closure of the Monroe bottom ash basin is expected in the
14 summer of 2024. Company Witness Lee describes the Company's closure plans
15 for multiple CCR sites in further detail in his direct testimony.

16

17 **Q42. Can you explain lines 21 and 49 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

18 A42. Lines 21 and 49 (Monroe Fly Ash Basin Closure (CCR)) represent a project
19 required by federal and state regulations. The existing Monroe Power Plant fly ash
20 basin will cease operations and be closed in place by dewatering the pond, grading
21 the existing fly ash, and installing an impervious synthetic membrane cover. The
22 existing fly ash basin utilizes a 400-acre pond with water depths up to 40 feet to
23 contain approximately 25 million cubic yards of fly ash. The Company spent \$0.5
24 million in 2022 to complete studies for conceptual compliance with the regulatory
25 requirements and selection of the detailed engineering and design contractor.

Line
No.

1 For 2023, \$4.5 million was projected to be spent to begin engineering and design.
2 During 2023, the engineering and design contractor initiated the dewatering system
3 design and capping plan, existing site documents were updated, field sampling of
4 soils was performed, site topography was surveyed, and a site grading plan was
5 established. Significant work effort was required to prepare the large number of
6 permits required by various municipalities, agencies, and authorities including U.S.
7 EPA, Michigan EGLE, Monroe County Drain Commission, Monroe County Road
8 Commission, and Monroe Township. The operating plan license agreement for the
9 basin closure project was prepared and filed with Michigan EGLE in 2023.

10

11 In 2024, \$5.0 million will be spent to continue engineering and design and develop
12 a request for proposal to perform the basin closure. Engineering and design scope
13 in 2024 will include fly ash basin dewatering and a water treatment system that
14 complies with all applicable environmental limits. Additionally, the engineering
15 and design contractor will develop an RFP to solicit bids from construction
16 management firms for project execution. The RFP will be issued in the fourth
17 quarter 2024.

18

19 In 2025, \$25.0 million is projected to award the ash basin closure construction
20 contract and begin project construction. In accordance with the Company's 2022
21 IRP Order, recovery of Monroe Power Plant investments for this project made after
22 January 1, 2025 will be through a regulatory asset, shown on line 49 of Exhibit A-
23 12, Schedule B5.1, page 2 of 9. This project is required by the EPA's CCR Rule
24 as discussed in Witness Lee's testimony.

25

Line
No.

1 **Q43. Can you explain line 22 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

2 A43. Line 22 (St. Clair Bottom Ash Basin Closure (CCR)) represents a project to clean
3 and close the St. Clair bottom ash basins by removal of all the CCR material,
4 decontamination, disposal, and basin backfill. The St. Clair bottom ash basins were
5 subject to forced closure per the CCR Rule requiring them to cease receipt of waste
6 and initiate closure as soon as technically feasible but by no later than April 11,
7 2021. As discussed in Witness Lee's testimony, the Company submitted a Part A
8 Rule demonstration for the St. Clair bottom ash basins, requesting an alternative
9 closure deadline based on cessation of coal-fired generation operations in spring of
10 2022, and a commitment to complete closure of the basins by October 17, 2023.
11 The Company initiated closure on September 1, 2022 and withdrew the requested
12 approval for a Part A Rule demonstration.

13

14 In 2022, \$7.9 million was spent to complete the detailed engineering, analysis of
15 soil borings, and elimination of source lines, followed by removal and
16 transportation of bottom ash from the basins to Range Road Landfill and backfill
17 the basins.

18

19 In 2023, \$0.4 million was spent on final project closure costs, including final
20 disposal of bottom ash, final backfilling, and issuance of a closure report. Basin
21 closure was completed in the first quarter of 2023.

22

23 **Q44. Can you explain lines 23-28 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

24 A44. Lines 23-28 detail steam plant removal costs associated with the retirement and
25 decommissioning of power generation assets at Harbor Beach, Conners Creek,

Line
No.

1 River Rouge, St. Clair, and Trenton Channel Power Plants. Removal of retired
2 steam generating units involves three primary activities, namely decommissioning,
3 decontamination, and demolition. Decommissioning activities include the cost to
4 isolate all unit systems and equipment to prepare them for removal from the site.
5 This includes electrical, mechanical, plant controls, water and gas service
6 shutdown, and electrical isolation from the transmission system. Decontamination
7 includes disposing of hazardous materials (including draining oils, chemicals, and
8 other fluids), cleaning tanks and pipelines, and removal of batteries and battery
9 systems. Demolition includes asbestos and lead abatement, tearing down buildings,
10 and removing and remediating the coal pile, ash basins, and ponds.

11

12 **Q45. Can you explain line 23 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

13 A45. Line 23 (Harbor Beach Decommissioning) is a project that finalized all site
14 activities associated with the decommissioning and subsequent demolition of the
15 Harbor Beach Power Plant. The Company spent \$17 thousand in 2022 for
16 monitoring the site developer's compliance to the sales contract terms.

17

18 **Q46. Can you explain line 24 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

19 A46. Line 24 (Conners Creek Seawall) was a project that restored the integrity of the
20 seawall at the Conners Creek Power Plant site through installation of new sheet
21 piling and associated shoreline repairs. The work was required to restore the
22 integrity of the site waterfront to address rising water levels and the existing
23 seawall's deteriorating condition that included separated tiebacks, undulating
24 pilings, and corroded piles. Without this work the shoreline was at risk for
25 sloughing into and impacting the Detroit River. The project was completed with

Line
No.

1 an expenditure of \$8.1 million in 2022 while fulfilling the permitting requirements
2 of the US Army Corps of Engineers and Michigan EGLE.

3

4 **Q47. Can you explain line 25 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

5 A47. Line 25 (River Rouge Decommissioning) is a project to fully decommission and
6 remove all plant structures including waste products from the site that has been in
7 operation for approximately 70 years. In the instant case, capital expenditures for
8 the River Rouge Power Plant decommissioning project support achieving a cold,
9 dark, and dry status by the end of 2024. This terminology refers to a state in which
10 the facility does not require heat or power, and all fluids have been removed from
11 their respective tanks, reservoirs, and piping systems. Project approval was
12 received from the Company in January 2023. The Company will address and
13 request the remaining decommissioning expenditures beyond achieving a cold,
14 dark, and dry state in a future rate case.

15

16 In 2022, \$13.0 million was spent to complete work that began in 2021 involving
17 environmental and site assessments. The Company also began plant electrical grid
18 isolation, removed plant natural gas feeds, performed industrial cleaning that
19 included removal of coal, oil, and chemicals from the site. The Company began
20 work in 2022 towards achieving a cold, dark, and dry state for the plant.
21 Additionally, plant utilities, such as city water and natural gas supply, have been
22 separated from the power plant proper and site outbuildings.

23

24 In 2023, \$21.1 million was spent to start asbestos abatement, environmental clean-
25 up, equipment removal, and continue electrical isolation of the power plant and site

Line
No.

1 outbuildings. Independence Demolition of Michigan was selected for initial work
2 activities.

3

4 In 2024, \$12.8 million is projected to be spent to complete electrical isolation of
5 the power plant and outbuildings by end of second quarter of 2024 and establish a
6 construction power feed for construction and various plant assets. Electrical
7 isolation of the plant will complete the process of making the plant cold, dark, and
8 dry.

9

10 **Q48. Can you explain line 26 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

11 A48. Line 26 (St. Clair Decommissioning) is a project to decommission St. Clair Power
12 Plant, which was in operation for approximately 70 years. The St. Clair
13 decommissioning was originally planned as a single project to achieve site
14 demolition and final site grading. Due to the fact that coal handling equipment,
15 boat unloading, firefighting, and control systems located on St. Clair property and
16 within the St. Clair Power Plant proper must be kept in-service until Belle River
17 Power Plant ceases coal-fired operations at the end of 2026, it was decided to
18 perform the St. Clair demolition project in two phases. Full Company authorization
19 for the first St. Clair decommissioning project to achieve cold, dark, and dry status
20 by the end of 2024 was received on March 22, 2023. The project scope discussed
21 below is associated with the first project. The Company will address and request
22 the second project in a future rate case.

23

24 In 2022, \$9.9 million was spent to sample for asbestos, lead, and PCBs, and to
25 define site conditions. The Company also performed decontamination work,

Line
No.

1 including the draining of oils, vacuuming of ash, washdown of boilers, and removal
2 of chemicals, and started evaluating the work required to electrically separate the
3 plant from the electrical grid. Engineering of systems to isolate plant water
4 connections to the environment was also completed, while still maintaining
5 operations of environmental systems, such as wastewater monitoring and oily waste
6 treatment.

7
8 For 2023, \$21.9 million was projected to be spent to continue work to achieve a
9 cold and dry state in the plant and start asbestos abatement. Environmental clean-
10 up and equipment removal in exterior outbuildings along with their demolition will
11 be initiated. All basins will also be emptied, cleaned and filled in 2023.

12
13 In 2024, \$13.0 million is projected to be spent to complete electrical isolation of
14 the plant from the electrical grid and continue abatement and demolition of exterior
15 outbuildings, namely structures associated with cooling water outfalls. Completion
16 of the electrical isolation work will place the plant in a dark state, completing all
17 cold, dark, and dry scope in the first project to decommission the St. Clair Power
18 Plant.

19

20 **Q49. Can you explain line 27 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

21 A49. Line 27 (Trenton Channel Decommissioning) is a project to fully decommission
22 and remove all plant structures including waste products from the Trenton Channel
23 Power Plant site that has produced power for approximately 100 years.

24

Line
No.

1 In 2022, \$10.0 million was spent to perform industrial cleaning, remove coal, oil,
2 chemicals, lead, and asbestos, and initiate electrical isolation of the power plant.
3 Additionally, the plant's natural gas feed was removed. All of these efforts were
4 required to reach a cold, dark, and dry state for the plant. The Company also
5 completed environmental and site assessments and developed a bid specification for
6 site demolition and grading.

7
8 For 2023, \$48.7 million was projected to be spent to continue decommissioning
9 efforts. Work completed in 2023 included awarding of a demolition contract to
10 Independence Demolition of Michigan, initiation of asbestos abatement and
11 environmental clean-up. Equipment removal in plant outbuildings along with their
12 demolition and the plant's electrical isolation was initiated. Electrical isolation of
13 the plant was completed and the plant reached a cold, dark, and dry state. The
14 project received full project approval by the Company in January 2023.

15
16 In 2024, \$35.0 million is projected to be spent to continue asbestos abatement,
17 removal of equipment inside the plant, and removal of stacks and the main turbine
18 house through explosive demolition. Filling of all basins will be initiated along
19 with the demolition of plant outbuildings in 2024. The stacks are scheduled to be
20 demolished in March 2024 and the main turbine house will be demolished in May
21 2024. The Company will also begin final site grading and soil remediation
22 activities.

23

Line
No.

1 In 2025, \$6.9 million is projected to be spent to conclude soil remediation and
2 complete final site grading. Performing these activities in the second quarter of
3 2025 will complete the decommissioning process.

4

5 **Q50. Can you explain line 28 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

6 A50. Line 28 (Trenton Channel Sea Wall) represents a project to restore the integrity of
7 the seawall at the Trenton Channel Power Plant and the installation of a pedestrian
8 greenway path along the Detroit River while meeting the permitting requirements
9 of the US Army Corps of Engineers, Michigan EGLE, and the City of Trenton. The
10 work includes removal of deteriorated sheet piles, maintenance of existing piles and
11 installation of new piles along the Detroit River and Slocum Canal shorelines.
12 Without this work, the shoreline was at risk for sloughing into and contaminating
13 the Detroit River and Slocum Canal. Development of the pedestrian greenway path
14 was stipulated in the approved demolition permit and will be installed along the
15 Detroit River riverfront after the power plant is demolished and site grading is
16 finalized.

17

18 In 2023, \$0.4 million was spent to begin engineering and design of the seawall,
19 natural shoreline, and greenway path.

20

21 In 2024, \$1.0 million is projected to be spent to complete engineering and design
22 of the seawall and begin engineering and design of the greenway path.

23

Line
No.

1 In 2025, \$9.5 million is projected to be spent to complete construction of the
2 seawall for the riverfront and canal and complete engineering, design and
3 construction of the greenway path by the end of 2025.

4

5 **Q51. Can you explain line 32 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

6 A51. Line 32 (Ludington Upgrades) represents an efficiency upgrade project at the
7 Ludington Pumped Storage Facility that was being managed by Consumers Energy,
8 Ludington's majority owner. The projected expenditures represent DTE Electric's
9 49 percent share of project costs. The upgrades of the six Ludington generating
10 units began in 2013. Ludington Unit 3, the final unit upgraded, had its work
11 completed for \$10.0 million in 2022 and \$1.5 million in 2023. Ludington Unit 3
12 returned to service on 2022, with a 34 MW increase of rated capacity now at 187
13 MW (DTE Electric's ownership percentage).

14

15 **Q52. Can you explain line 35 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

16 A52. Line 35 (Blue Water Energy Center (CCGT)) represents a project to build a 1,127
17 net MW (summer-rated capacity) CCGT generating plant on 40 acres of Company
18 property adjacent to the existing Belle River Power Plant. This location was
19 strategically selected due to its proximity to transmission lines and high-pressure
20 natural gas pipeline infrastructure. The plant completed construction and became
21 commercially operational in June of 2022. The unit generated 4,593 GWh during
22 its first seven months of operation at an ROF less than 5% and a net heat rate of
23 only 6,492 BTU/kWh.

24

Line
No.

1 On April 27, 2018, the MPSC issued an Order in Case No. U-18419 approving DTE
2 Electric's construction of this plant and authorized the Company to recover up to
3 \$951.8 million in costs for the plant through future rates.

4

5 In 2022, \$11.8 million was spent to support plant startup, testing, and
6 commissioning.

7

8 For 2023, the Company expected a net credit to the project in the amount of \$4.5
9 million, primarily driven by a \$1.4 million credit in March 2023 for a refund from
10 ITC that came in higher than anticipated due to an interest rebate and a \$3.2 million
11 credit in June 2023 for a Canadian tax refund on natural gas purchased to support
12 startup testing.

13

14 In 2024, \$6.0 million is projected to be spent to complete punch list items and as-
15 built drawings.

16

17 Final project costs are awaiting completion of final punch list items and as-built
18 drawings in 2024. The Company currently projects total project costs of \$946.5
19 million, which is below the \$951.8 million approved by the Commission. This is
20 an outstanding outcome, especially given the fact the project was constructed in the
21 midst of the COVID-19 pandemic.

22

23 **Q53. Can you explain line 36 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

24 A53. Line 36 (BWEC Transmission Upgrades) represents transmission upgrades
25 required for BWEC to acquire MISO generator interconnection rights. Since

Line
No.

1 transmission network upgrades were excluded from the \$951.8 million approved
2 for the construction of BWEC in MPSC Case No. U-18419, this project is distinct
3 from line 35 (Blue Water Energy Center (CCGT)).

4

5 In 2022, \$5.5 million was booked for ITC transmission tower modifications. Due
6 to the transmission line routing from the plant's electrical mat to the ITC substation,
7 existing ITC transmission towers and their connecting transmission lines were
8 raised to accommodate the installation of the dedicated BWEC transmission lines
9 crossing under them.

10

11 In 2023, a refund of \$4.8 million was credited back against the \$9 million paid in
12 2021 for the Benton Harbor transformer project. This credit was received after new
13 generating projects completed by other companies requested rights to and
14 compensated the Company for utilizing part of the grid transmission capabilities
15 previously funded by the Company through this project.

16

17 **Q54. Can you explain line 37-39 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

18 A54. Lines 37-39 (Blackstart Projects 1-3) represent projects that support the North
19 American Electric Reliability Corporation (NERC) black start plan. Each region
20 designates certain generating plants as black start units. A black start unit is one
21 that can startup utilizing only its own internal power without support from the grid
22 in the event of a major grid blackout, such as the 2003 blackout. This capability is
23 critical to reestablishing grid integrity and restarting non-black start capable power
24 plants following a grid blackout. In the Company's previous rate case, Case No.
25 U-21297, ITC explained, "NERC requires each transmission operator to have a

Line
No.

1 system restoration plan (SRP) and that a black start unit is an SRP” and that, “it is
2 critical to the safety and reliance of the grid.”² ITC further cautioned that black
3 start resources are being lost through conventional generation retirements and that
4 the Company’s investments in the black start resources will ensure a resilient SRP.
5 The black start unit project details disclosed are limited to maintain the integrity of
6 these critical sites. ITC echoed this need for limited disclosure in the previous rate
7 case, explaining, “the fact that some people outside the Company may have
8 information regarding the black start resource projects (and [are] required to
9 safeguard such information) does not vitiate the need for confidentiality and
10 sensitive treatment of these projects.”³ The Commission was persuaded of the
11 importance of these projects in maintaining grid security in their Final Order dated
12 December 1, 2023⁴, in Case No U-21297. Project major work efforts, timelines,
13 and expenditures are discussed in detail below.

- 14
15 • Line 37 (Blackstart Project 10570 & 20255) represents a project that
16 provides fuel and controls systems capabilities to enable a peaker site to
17 startup without power from the grid. The project received Company
18 approval in 2021.

19
20 In 2022, \$20.7 million was spent to complete design and initiate
21 construction of fuel system modifications, develop, award, and initiate
22 execution of mechanical erection contracts, and finalize the electrical
23 erection specifications.

² December 1 order, page 42

³ December 1 order, page 43

⁴ December 1 order, page 43

Line
No.

1

2

For 2023, \$10.4 million was projected to be spent to complete the fuel system modifications and testing and to install major electrical components.

4

5

In 2024, \$2.2 million is projected to be spent to complete all construction activities, commission the installed equipment, and perform final project closeout activities including drawing updates.

6

7

8

9

- Line 38 (Blackstart Project 17611) represents a project that provides an existing site new equipment and controls that enable the peaker site to startup without power from the grid. The project received Company approval in June 2022.

10

11

12

13

14

In 2022, \$0.1 million was spent on project management activities.

15

16

In 2023, \$2.0 million was spent to bid and procure switchgears and two generators and to complete engineering efforts.

17

18

19

In 2024, \$6.1 million is projected to be spent to complete all construction activities and commission the installed equipment.

20

21

22

- Line 39 (Blackstart Project 18320) represents a project that provides an existing site equipment and controls that enable the peaker site to startup without power from the grid. The project received Company approval in January 2023.

23

24

25

Line
No.

1 In 2022, \$1.1 million was spent to initiate the project, bid and award
2 engineering, and procure the diesel generators and automatic transfer
3 switch.

4

5 For 2023, \$4.0 million was projected to be spent to bid and award equipment
6 installation, receive project materials, perform the equipment installation,
7 and commission the installed equipment. This allows the unit to return to
8 service until final long lead material is received in 2024.

9

10 In 2024, \$0.4 million is projected to be spent to receive final long lead
11 transfer switch, complete equipment installation, commission, and close out
12 the project.

13

14 **Q55. Can you explain line 40 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

15 A55. Line 40 (Slocum Battery Pilot) represents a project to replace the diesel-fueled
16 peakers at the Company's Slocum peaker site located in the City of Trenton with a
17 14 MW / 56 MWhr lithium-ion (Li-ion) BESS. The BESS will store excess energy
18 that is generated on the grid during off-peak hours. This energy will then be
19 available for dispatch during higher-priced peak hours.

20

21 In 2022, \$7.6 million was spent for vendor selection and initial engineering work.
22 These work activities included a bid specification and RFP for major equipment.
23 Vendors for major equipment were selected and progress payments for long lead
24 materials (i.e., batteries and transformer) were initiated. Those progress payments
25 included two payments to the transformer supplier and one payment to the battery

Line
No.

1 supplier. Delivery of all major equipment is scheduled to occur between the first
2 quarter and third quarter of 2024.

3

4 In 2023, \$10.1 million was spent to finish engineering, continue the procurement
5 of materials, complete the construction bid package, and issue and award an RFP
6 for construction. Additionally, the existing diesel peakers and their supporting
7 equipment were decommissioned and removed from the site.

8

9 In 2024, \$26.8 million is projected to be spent to support a 2024 installation and
10 startup of BESS commercial operations in November 2024.

11

12 In 2025, \$0.1 million is projected to be spent for final project closeout costs.

13

14 **Q56. What is the Slocum Battery Pilot anticipated total project cost?**

15 A56. The Slocum Battery Pilot project costs are projected to be \$44.7 million. That
16 amount has increased from prior projections primarily due to increases in lithium
17 costs and actual construction bids received. Despite the cost increases, the Slocum
18 battery pilot continues to provide the Company valuable insights and learnings on
19 a small-scale project which will help the Company, contractors, and local
20 municipalities succeed on the planned larger scale upcoming projects.

21

22 **Q57. Can you explain line 41 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

23 A57. Line 41 (Trenton Channel Energy Center BESS) represents expenditures associated
24 with a 220 MW / 880 MWhr Li-ion BESS build, consistent with the build plan
25 approved in the Company's 2022 IRP Order. The forecast includes the

Line
No.

1 expenditures needed for engineering and long lead material procurement to support
2 a 220 MW BESS starting commercial operations in 2026. The project received full
3 internal Company approval in October 2023.

4

5 In 2023, \$5.3 million was spent to bid and award equipment, and procure long lead
6 materials (i.e., electrical breakers and transformer).

7

8 In 2024, \$120.7 million is projected to be spent to take delivery of major electrical
9 equipment and begin site preparation and construction in the fourth quarter of 2024.

10 The Company executed contracts with the EPC contractor and battery vendor in
11 January 2024, and these were submitted to the MPSC as noted below.

12

13 In 2025, \$291.9 million is projected to be spent to take delivery of batteries and
14 electrical collection equipment for the battery inverters and complete construction
15 of the substation and BESS electrical switchyard.

16

17 As required in the Company's 2022 IRP Case No. U-21193, contracts totaling \$334
18 million, which represents nearly 80% of the total projected spend for this project,
19 were approved by the Commission in March 2024 in Case No. U-21566. The
20 remaining 20% of project costs, totaling \$89 million, include interconnection costs
21 and permits (\$23 million), BESS commodities and environmental remediation (\$10
22 million), subgrade stabilization and fire suppression (\$10 million), auxiliary
23 transformer (\$2 million), DTE labor (\$3 million), owner's engineer and expert
24 support costs (\$6 million), project overheads (\$16 million), and AFUDC (\$19
25 million). The Company plans for the Trenton Channel Energy Center BESS to

Line
No.

1 reach commercial operations in March 2026. Therefore, it is classified as
2 construction work in progress (CWIP) through the projected period of this case. As
3 explained by Witness Uzenski, projects in CWIP with an AFUDC offset do not
4 impact the revenue requirement.

5

6 **Q58. Can you explain line 42 of Exhibit A-12, Schedule B5.1, page 2 of 9?**

7 A58. Line 42 (Northeast 11-1 Decommissioning) represents a project to decommission
8 the Northeast 11-1 peaker unit that retired in 2023.

9

10 For 2023, \$0.3 million was projected to be spent to electrically disconnect the
11 generator from the electrical grid, drain lube oil from the generator, and begin
12 engineering of the decommissioning project. Engineering work will include
13 environmental protections, isolation of fuel source, disabling of the fire protection
14 system, and plant controls systems modifications.

15

16 In 2024, \$0.3 million is projected to be spent to complete engineering of the
17 decommissioning and execute the separation work needed on the peaker unit.

18

19 **Routine Capital Expenditures**

20 **Q59. What information is provided on page 3 of Exhibit A-12, Schedule B5.1?**

21 A59. Page 3 provides a summary of the routine capital expenditures for steam power,
22 hydraulic power (Ludington), and other power generation facilities from the
23 beginning of 2022 through December 31, 2025, broken down by site and by major
24 spending category. Routine capital projects include projects to maintain plant
25 reliability, maintain environmental compliance, provide safe operation of

Line
No.

1 equipment, and improve efficiency, all with a focus on providing the customer
2 affordable, low-cost generation. The Company has included all Monroe routine
3 2025 expenditures in a regulatory asset shown on Exhibit A-12, Schedule B5.1,
4 page 3, line 13, consistent with the Commission's final Order in the Company's
5 2022 IRP filing, Case No. U-21193.

6

7 **Reductions to Monroe Unit 3 and 4 Capital Expenditures and Updates to the Capital**

8 **Projects Planned**

9

10 **Q60. What types of work do typical Monroe Power Plant major periodic outages**
11 **include?**

12 A60. Monroe units are brought offline once every four years for approximately three
13 months to perform major periodic outages. During these outages, major
14 maintenance is performed on the unit's systems, such as the boiler and steam
15 turbines, to ensure future safe, reliable, efficient, and environmentally compliant
16 operations.

17

18 **Q61. As Monroe Units 3 and 4 approach retirement scheduled for the end of 2028,**
19 **how has the Company modified its periodic outage capital expenditure plans?**

20 A61. Prior to the Company's 2022 IRP in which the Company advanced the timing of
21 the retirement of Monroe Units 3 and 4 from 2040 to 2028, the Company was
22 anticipating investing over \$200 million of capital expenditures during the Monroe
23 Unit 3 2024 and Monroe Unit 4 2025 periodic outages to replace sections of boiler,
24 replace turbine rotors and blades, and perform other maintenance critical for
25 extended unit operation. Given the limited timeframes between the upcoming

Line
No.

1 Monroe Unit 3 and 4 periodic outages and their pending retirements in 2028, the
2 Company has scaled back or eliminated many capital projects previously planned
3 to support operations until 2040. The planned scope reductions will lower routine
4 large capital expenditures by approximately 50 percent, to just over \$100 million
5 for the Monroe Unit 3 and 4 periodic outages in 2024 and 2025. In addition to this
6 reduction in Monroe Unit 3 and 4 routine capital project periodic outage
7 expenditures, an additional \$100 million of regulatory-mandated non-routine ELG-
8 related investments for these units is no longer required and customers have been
9 saved the expenditures.

10

11 **Q62. Has the Company discussed changes in capital projects on Monroe Units 3 and**
12 **4 under a 2028 retirement in a previous filing?**

13 A62. Yes. In the Company's 2023 electric rate case, MPSC Case No. U-21297, the
14 Company delineated the avoidable and unavoidable capital expenditures that would
15 be possible if Monroe Units 3 and 4 were to retire in 2028. Since that filing, further
16 information has come to light that has resulted in updates to the scope and costs of
17 the unavoidable capital investment requirements for the upcoming Monroe Unit 3
18 and 4 periodic outages.

19

20 **Q63. What routine capital project scope planned for the Monroe Unit 3 periodic**
21 **outage in 2024 required updating since the last rate case, Case No. U-21297?**

22 A63. Since the initial filing of the last rate case, nine projects have been cancelled on
23 Monroe Unit 3 with seven other projects being executed as previously planned.
24 Recent unit equipment inspections and failures have also triggered the Company to
25 move forward with two capital projects not previously anticipated to be required

Line
No.

1 under a 2028 retirement. These projects now deemed as required at this time
2 include the Air Heater Cold-End Basket Replacement Project and the Horizontal
3 Reheat Tube Replacement Project. Additionally, the Company has determined that
4 the turbine valve project should fully overhaul all eight governor valves based on
5 age and condition of internal parts and four throttle valves due to valve seats
6 cracking and weld failures. The original turbine valve project anticipated requiring
7 only limited inspections and repairs of some of the valves which previously made
8 that portion of the work an O&M expense instead of a capital asset replacement.
9 Finally, the Company has reduced the Unit 3 DCS project by approximately 40
10 percent to focus on only completing work scope critical for continued unit
11 operations until retirement of the unit at the end of 2028. I elaborate on these
12 project justifications and further explain these updates below.

13

14 **Q64. What is the current condition of the Monroe Unit 3 air heater cold-end**
15 **baskets?**

16 A64. The Monroe Unit 3 air heater cold-end baskets were installed in 2015 and have a
17 typical life expectancy of 7-10 years. The existing baskets are failing due to
18 material loss caused by normal operational corrosion. Recent inspections show 30
19 percent of the basket material has been lost. If the air heater baskets are not
20 replaced, continued material loss will cause air heater imbalances requiring unit
21 outages to clean and balance the air heater, while risking likely drive gear failures.
22 A gear drive failure will cause the unit to be in a multi-week forced outage until
23 repairs to the air heater(s) are completed. The plant has already experienced two
24 air heater failures in recent years on Monroe Unit 2, in which elements fell out and
25 jammed the air heater drive resulting in multi-week forced outages. Additionally,

Line
No.

1 not performing the project would increase the heat rate of future operations.
2 Furthermore, the discounted payback for the project was calculated to be 2.2 years,
3 well within the projected operating life of the unit. Alternatively, if this project was
4 not completed, in addition to the costs associated with cleaning and balancing the
5 air heaters, the forecasted costs to customers from each air heater failure event
6 between 2024 and 2028 would be \$0.5 million in repair costs and over \$3 million
7 in purchase power expense during a 2-week forced outage repair.

8

9 **Q65. What is the current condition of the Monroe Unit 3 horizontal reheater?**

10 A65. The Monroe Unit 3 horizontal reheater is original to the unit and is failing due to
11 oxygen pitting corrosion and fly ash erosion. Since Monroe Unit 3's last periodic
12 outage in 2019, the unit experienced nineteen horizontal reheater tube leaks, forcing
13 the unit offline for multiple weeks to perform repairs. During inspection of the
14 failed reheater tubes, oxygen pitting damage was found. The Company plans to
15 replace 4,000 linear feet of tubes in the most heavily damaged areas to minimize
16 future horizontal reheater tube leaks until the unit's 2028 retirement. Without the
17 project, the Company anticipates at least one additional tube leak outage requiring
18 extensive repairs each year. Reheater repairs are difficult and often lengthy because
19 tight tube spacing can necessitate cutting away undamaged tubes to gain access to
20 complete required repairs and then restoring those removed tubes to complete the
21 repair effort. Additionally, such tube failures often cause collateral damage to
22 surrounding tubes. The discounted payback for the project was calculated to be 1.8
23 years, well within the projected operating life of the unit. Alternatively, if this
24 project was not completed, the forecasted costs to customers from each horizontal
25 reheater tube leak event between 2024 and 2028 would be \$0.5 million in repair

Line
No.

1 costs and over \$3 million in purchase power expense during a 2-week forced outage
2 repair.

3

4 **Q66. What scope was added to the Monroe Unit 3 Turbine Valves project in the**
5 **2024 periodic outage since the last rate case, Case No. U-21297?**

6 A66. In 2023, further analysis of turbine valve scope was completed, leading to updated
7 repair plans for the governor valves and throttle valves.

8

9 That further analysis included a review of age and condition of internal valve
10 components which indicated that the eight governor valves needed to have their
11 stems, bushing, and seats replaced. This scope of work will ensure proper operation
12 of this critical safety system that is required for turbine control and safe shutdown.

13

14 Additionally, the Company plans to overhaul all four Monroe Unit 3 throttle valves
15 due to the valve seat failures observed in 2022 at Belle River Power Plant. Over
16 many years of normal operations at high temperatures (1000°F), valve seats
17 containing stellite alloys become brittle, crack, and fail, causing damage to
18 downstream turbine blades. Thus, the Company plans to proactively replace the
19 throttle valve seats before turbine damage occurs.

20

21 Without routine overhaul of these valves, there is risk of the valves not functioning
22 properly, leading to damage to the unit's turbines or an overspeed condition
23 resulting in catastrophic turbine failure. Accordingly, this project is classified as a
24 safety project.

25

Line
No.

1 **Q67. What is the status of the Monroe Unit 3 DCS and Control Room upgrade**
2 **project?**

3 A67. The Monroe Unit 3 DCS and Control Room project cost has been reduced from
4 \$5.0 million to \$3.1 million. In the Company's 2023 main electric rate case, Case
5 No. U-21297, the costs for this project were excluded from the approved revenue
6 requirement because the Company was reviewing the need for the upgrades and the
7 necessity for the project was less certain. During 2023, the Company reduced the
8 project scope to one that is solely focused on critical work necessary to support
9 continued operations. Scope removed from the project included demolition of
10 original alarm panels, integration of a display that monitors and controls electrical
11 control positions throughout the unit, and furniture replacements. Without at a
12 minimum performing this scaled-down project, the Company expects chronic
13 controls component failures to cause derates and outages equivalent to multiple
14 outage days per year. The discounted payback for the project was calculated to be
15 2.2 years, well within the projected operating life of the unit. Additionally, the
16 project maintains consistency in the control systems design and function across all
17 four units at Monroe. This continuity of design and function is critical to avoid
18 human performance errors as operators routinely move from unit to unit.

19

20 **Q68. Besides scope updates to Monroe Unit 3 periodic outage projects, what**
21 **additional updates has the Company included in the filing of the instant rate**
22 **case?**

23 A68. The Company has updated cost projections based on the latest information
24 available. For two projects, the Monroe Unit 3 Coal Mill Classifiers project and
25 the Monroe Unit 3 Waterwall Tubes project, costs to complete the projects are

Line
No.

1 forecasted to be approximately \$1 million more for each individual project than the
2 scaled down costs estimated in Case No. U-21297.

3

4 **Q69. Why did Monroe Unit 3 Coal Mill Classifier project cost projections increase**
5 **since Case No. U-21297?**

6 A69. In Case No. U-21297, the Company inadvertently presented only contractor labor
7 costs as unavoidable costs related to the scaled down version of the Unit 3 Coal
8 Mill Classifier project and did not include materials and overheads to perform the
9 scaled down version of the project. Accordingly, project costs in the instant case
10 now include \$0.6 million for materials and \$0.7 million of overheads (indirect and
11 shared costs). The scope remains consistent with the scaled down version of the
12 project described in Case No. U-21297 and includes replacement of the upper and
13 lower bearings based on OEM recommendations, as opposed to the previously
14 planned full classifier overhaul project that was projected to exceed \$5 million.
15 Alternatively, if the bearings are not replaced, each bearing that fails will require
16 the respective coal mill to be forced offline for emergent repair and result in a
17 derated capacity for the unit. The discounted payback for the project was calculated
18 to be 2.0 years, well within the projected operating life of the unit.

19

20 **Q70. Why did Monroe Unit 3 Waterwall Tubes project cost projections increase**
21 **since Case No. U-21297?**

22 A70. In 2023, the Company procured the waterwall materials and evaluated installation
23 labor bids for the Monroe Unit 3 Waterwall Tubes project. While the Commission
24 excluded 50 percent of the project costs from rate base in Case No. U-21297 based
25 on MPSC Staff's assumptions that costs would reduce 50 percent if the square

Line
No.

1 footage being replaced was reduced by 50 percent, the actual bids received did not
2 provide the 50 percent reduction assumed by the MPSC Staff. The cost projection
3 for the revised project now totals \$13.6 million, consisting of \$8.8 million for
4 installation labor, \$1.1 million for scaffolding, \$0.5 million for materials, \$0.7
5 million in shared costs, \$0.4 million for inspections, \$0.3 million in other contract
6 labor (including abatement, air monitoring, engineering, electrical, and industrial
7 cleaning), \$0.3 million in DTE Electric labor, and \$1.5 million for overheads. The
8 scope in the instant case remains consistent with the scaled down version of the
9 project described in Case No. U-21297 and includes replacement of 2,000 square
10 feet of waterwall panels, as opposed to a full, 4,000 square foot replacement project
11 that was projected to cost \$19 million. Based on tube thickness measurements and
12 tube wastage trends, in addition to data from other failure modes, Monroe Unit 3's
13 boiler will experience multiple tube leak forced outages annually if the scaled back
14 waterwall replacement project is not completed. The costs to customers from each
15 waterwall tube leak event between 2024 and 2028 is approximately \$0.4 million in
16 repair costs and \$1-2 million in purchase power expense during each 1-week forced
17 outage repair. The discounted payback for the project was calculated to be 2.7
18 years, well within the projected operating life of the unit.

19

20 **Q71. What projects had their scope updated since the last case, Case No. U-21297,**
21 **for the Monroe Unit 4 periodic outage in 2025?**

22 A71. In 2023, the Company further reviewed and reduced the Unit 4 DCS Project scope
23 to minimize scope to only that scope of work critical for continued operation to
24 retirement. Additionally, the need for a reasonable amount of preventative
25 maintenance continues to be validated. For example, the Monroe Unit 4 south

Line
No.

1 boiler feed pump condenser project was originally scheduled to be completed in
2 2025 but required execution in 2023 on an emergency basis.

3

4 **Q72. What is the status of the Monroe Unit 4 DCS and Control Room project?**

5 A72. Consistent with the prior discussion involving the Monroe Unit 3 DCS and Control
6 Room project above (Q/A 67), the Monroe Unit 4 DCS and Control Room project
7 has been reduced to \$2.6 million which is the amount necessary to support
8 continued operation and address major reliability risks associated with obsolete
9 equipment which is no longer supported by vendors. Without performing this
10 scaled-down project, the Company expects chronic controls component failures
11 resulting in derates and outages equaling multiple outage days per year. The
12 discounted payback for the project was calculated to be 2.5 years, well within the
13 projected operating life of the unit. Additionally, the project maintains consistency
14 in the control systems design and function amongst all four units at Monroe. This
15 continuity of design and function is critical to mitigating the risk of human
16 performance errors for the operators running the units.

17

18 **Q73. Why did the Monroe Unit 4 south boiler feed pump turbine (SBFPT)**
19 **condenser require retubing in 2023?**

20 A73. The south boiler feed pump turbine condenser required retubing in 2023 because in
21 February of 2023 a large number of condenser tubes developed leaks in this
22 equipment which was original to Monroe Unit 4. Over time, the condenser required
23 39 percent of its cooling water tubes to be plugged to stop leaks caused by ammonia
24 grooving, erosion, and stress corrosion cracking. After tubes are plugged, water
25 velocities through the remaining tubes increase causing additional wear. The old

Line
No.

1 condenser was not capable of providing the heat transfer required to operate the
2 boiler feed pump turbine at full capacity without causing turbine blade damage due
3 to increased back-pressure. Without the condenser in-service, the unit is limited to
4 half load operations. The discounted payback for the project was calculated to be
5 1.5 years, well within the projected operating life of the unit.

6

7 **Routine Capital Expenditures - Steam Power Generation**

8 **Q74. What were the Company's routine capital expenditures completed in 2022 for**
9 **Steam Power Generation?**

10 A74. During 2022, the Company's Energy Supply group routine capital expenditures
11 related to Steam Power Generation were \$219.0 million as shown on Exhibit A-12,
12 Schedule B5.1, page 3 of 9, line 7, column (b). These expenditures included the
13 following projects that individually exceeded \$1 million as detailed on page 4 of
14 Exhibit A-12, Schedule B5.1:

- 15 • The Belle River Unit 1 low pressure (LP) turbine rotors and blades were
16 replaced for \$5.4 million (Exhibit A-12, Schedule B5.1, page 4, line 1).
17 Inspections had identified blade erosion and rotor cracking that needed to be
18 addressed to ensure continued safe and reliable operation of the LP turbines.
- 19 • The Belle River Unit 1 turbine valve actuators were replaced for \$4.0 million
20 (Exhibit A-12, Schedule B5.1, page 4, line 2). The original actuators
21 provided by the OEM have been replaced across the industry due to
22 maintenance issues, lack of spare parts, and an absence of qualified
23 companies capable of repairing them. The replacements were required to
24 ensure the continued reliable operation of this system that controls turbine

Line
No.

- 1 loading. Failure of these valves to properly operate would impact the ability
2 to properly control unit output.
- 3 • Waterwall tubes were replaced on Belle River Unit 1 for \$3.8 million
4 (Exhibit A-12, Schedule B5.1, page 4, line 3). The project replaced 2,100
5 square feet of boiler waterwall panels damaged by the ordinary wear and tear
6 of quench cracking and soot blower erosion to support continued reliable
7 boiler operation.
 - 8 • Belle River Unit 1 high pressure (HP) turbine blades were replaced for \$3.4
9 million (Exhibit A-12, Schedule B5.1, page 4, line 4). During disassembly
10 of the HP turbine stop valves at the start of the 2022 periodic outage, it was
11 discovered that stop valve disk wear-resistant stellite coatings had failed and
12 likely entered the HP turbine. During the previous 2016 periodic outage, the
13 valves were inspected and had shown no indications of dis-bonding failures.
14 Further turbine inspections revealed that 11 rows of rotating and stationary
15 blades of the HP Turbine were suffering from foreign object damage and
16 needed to be replaced. By addressing the damage during this periodic
17 outage, the Company was able to potentially avoid a future significant forced
18 outage likely in excess of 90 days to complete the repair.
 - 19 • Underground electrical cables (each approximately 1-mile long) from Belle
20 River Unit 1 to the condenser cooling water intake structure located on the
21 St. Clair River were replaced for \$2.8 million (Exhibit A-12, Schedule B5.1,
22 page 4, line 5). The intake structure equipment provides water from the river
23 to the plant. Testing of the power feed cables following recent failures had
24 indicated degradation of the cables, necessitating replacement to ensure
25 continued safe and reliable operation.

Line
No.

- 1 • The Belle River Unit 1 boiler ignitor system was replaced for \$2.2 million
2 (Exhibit A-12, Schedule B5.1, page 4, line 6). The ignitor system was
3 replaced to address the operational issues that have developed into safety
4 concerns for the operators working the burner decks. The ignitors on Unit 1
5 are original equipment and have been in service since 1984. The
6 performance of the ignitor components has degraded, frequently failing to
7 insert when required, which then requires the operator to manually position
8 these components. This puts the operator at risk to mechanical and electrical
9 hazards.
- 10 • The Belle River Unit 1 HP turbine valves were rebuilt for \$2.1 million
11 (Exhibit A-12, Schedule B5.1, page 4, line 7) as part of the normal scheduled
12 work on these valves to ensure continued proper operations. The stellite
13 coatings on the valve seat disks were found to be delaminated, releasing
14 foreign material into the turbine requiring extensive HP turbine blade
15 repairs, as discussed above. The HP turbine stop valves and control valves
16 must operate properly to provide overspeed protection for the turbine and
17 prevent possible catastrophic failure.
- 18 • Belle River Unit 1 primary air heater baskets were replaced for \$2.0 million
19 (Exhibit A-12, Schedule B5.1, page 4, line 8). As air heater baskets
20 deteriorate with age, the basket plates become loose and can drop into the
21 moving ductwork and prevent the air heater from rotating. Without a
22 properly functioning air heater, the unit cannot operate. Additionally, the
23 basket replacements improve boiler efficiency.
- 24 • A portion of the horizontal middle reheater on Belle River Unit 1 was
25 replaced for \$1.4 million (Exhibit A-12, Schedule B5.1, page 4, line 9). The

Line
No.

1 horizontal reheater is located within the downdraft section of the boiler.
2 These tubes were replaced due to preferential corrosion of original
3 construction shop welds that were compromised by acidic corrosion taking
4 place during boiler washes that remove ash and slag accumulations
5 associated with utilization of low sulfur western fuel at the plant. These
6 tubes required replacement to avoid tube failure outages.

7 • Belle River Unit 1 generator phase bushings were replaced for \$1.2 million
8 (Exhibit A-12, Schedule B5.1, page 4, line 10). In early 2020, the plant
9 discovered that the Z-phase generator bushing (insulator) seal had failed and
10 was leaking hydrogen. Inspection of the remaining five (5) generator
11 bushings identified signs of deterioration requiring replacement to prevent a
12 failure that would release hydrogen into the plant and force a unit outage.

13 • \$1.1 million was spent to rebuild the purple coal mill on Belle River Unit 1
14 due to service hours and lube oil analysis indications of deteriorating internal
15 components (Exhibit A-12, Schedule B5.1, page 4, line 11). Due to the
16 abrasiveness of coal, coal mill parts experience significant wear in the
17 process of converting lump coal to a fine powder consistency suitable for
18 boiler combustion and need to be disassembled, repaired, and components
19 replaced approximately every 10 years. Purple coal mill was last overhauled
20 in 2012 and was due for this work.

21 • Two (2) induced draft (ID) fan motors on Belle River Unit 1 were replaced
22 for \$1.0 million (Exhibit A-12, Schedule B5.1, page 4, line 12). These
23 motors require overhaul/replacement approximately every 10 years and the
24 motors were due for this work.

Line
No.

- 1 • In preparation for the Belle River Unit 2 planned outage in 2024, \$2.9
2 million was spent to engineer and procure replacement LP turbine rotors and
3 blades (Exhibit A-12, Schedule B5.1, page 4, line 13). Inspections identified
4 blade erosion and rotor cracking that needed to be addressed to ensure
5 continued safe and reliable operation of the LP turbines.
- 6 • The Belle River fuel supply east main coal pile project was completed for
7 \$2.3 million (Exhibit A-12, Schedule B5.1, page 4, line 14). The east main
8 coal pile was used to fuel both St. Clair Power Plant and Belle River Power
9 Plant. When St. Clair Power Plant retired in 2022, the existing equipment
10 required modification to eliminate the risk of safety hazards (fires) due to
11 combustible dust and coal accumulation stranded in the equipment no longer
12 in operation. This modification required the removal of non-operational
13 diverter gates and chutes, removal of dust collector ductwork and installation
14 of new ductwork, installing a new metal (tramp iron) detection system,
15 removal of two abandoned coal bins and four slide gates, installation of a
16 new transfer chute, new instrumentation, and a new dust suppression system.
17 Isolating the abandoned St. Clair Power Plant conveyor systems through
18 installation of barriers was required to prevent coal and combustible dust
19 from entering the retired St. Clair Power Plant fuel system where it would
20 create a risk of fire or explosion.
- 21 • \$1.8 million was spent to replace the Belle River fuel supply DCS consoles
22 (Exhibit A-12, Schedule B5.1, page 4, line 15). The previous system was
23 obsolete and required an upgrade to ensure reliable communication and
24 eliminate compatibility issues with the Belle River Power Plant DCS.

Line
No.

1 Additionally, this ten-year-old equipment was no longer supported by the
2 vendor.

3 • Belle River 3TH-8 fuel supply dust collector was replaced for \$1.7 million
4 (Exhibit A-12, Schedule B5.1, page 4, line 16). The dust collector in the fuel
5 supply system collects dust that is inherent to the transportation of coal via
6 conveyor belts. The dust is collected from multiple points along the fueling
7 system via several large ducts that are under vacuum. The dust collector
8 filters the dust laden air, allowing the clean air to exhaust back to the
9 atmosphere, while the coal dust is transported by screw conveyors back to
10 the conveyor belts. The replacement mitigates combustible dust and
11 complies with the National Fire Protection Association (NFPA) combustible
12 dust guidelines.

13 • \$1.7 million was spent to begin separation of St. Clair Power Plant from the
14 Fuel Supply system (Exhibit A-12, Schedule B5.1, page 4, line 17). There
15 are a number of systems in the St. Clair Fuel Supply system that are
16 interrelated with the Belle River Power Plant as all coal deliveries to Belle
17 River are unloaded at and pass through the St. Clair Power Plant fuel supply
18 system. Although St. Clair Power Plant retired in 2022, these interrelated
19 systems must remain functional to continue fueling the Belle River Power
20 Plant until its ultimate conversion to operation on natural gas. The project
21 scope was to completely separate St. Clair Power Plant from the Fuel Supply
22 System that will continue to be operated in support of Belle River Power
23 Plant. The scope of the separation effort included fire protection, general
24 service water, wastewater, stormwater, low voltage electrical, and medium
25 voltage electrical switchgear systems.

Line
No.

- 1 • The Belle River fuel supply CV2 to CV4 transfer chute was replaced for \$1.3
- 2 million (Exhibit A-12, Schedule B5.1, page 4, line 18). This chute was
- 3 replaced to prevent combustible coal and dust accumulation that would
- 4 become a safety hazard.
- 5 • In preparation of the Greenwood Unit 1 outage in 2025, \$7.6 million was
- 6 spent on engineering and initial material procurement efforts for LP turbine
- 7 rotors and blades (Exhibit A-12, Schedule B5.1, page 4, line 19). Stress
- 8 corrosion cracking of multiple blade root connections needs to be addressed
- 9 to ensure continued safe and reliable operation of the LP turbines.
- 10 • The Greenwood Unit 1 north induced draft (ID) fan was overhauled for \$1.0
- 11 million (Exhibit A-12, Schedule B5.1, page 4, line 20). Inspections
- 12 conducted following an instance of abnormal vibration levels revealed
- 13 bearing wear beyond the operational tolerance specifications and hydraulic
- 14 fluid leaks. The increasing vibration needed to be addressed to ensure
- 15 continued reliable operations.
- 16 • In preparation for the Monroe Unit 1 2023 periodic outage, \$9.6 million was
- 17 spent to procure material for fabrication of new LP turbine rotors and blades
- 18 (Exhibit A-12, Schedule B5.1, page 4, line 21). Inspections were conducted
- 19 and revealed the expected ordinary wear and tear on the L-0 through L-5
- 20 blade rows. This project also addressed stress corrosion cracking concerns
- 21 on the original LP turbine forgings which are an industry-wide safety
- 22 concern. Additionally, SCR catalyst modules for layers 1, 2, and 4 were
- 23 purchased for \$4.0 million (Exhibit A-12, Schedule B5.1, page 4, line 22).
- 24 The catalyst module replacements were required to maintain compliance
- 25 with air permit emission limits for NOx and ammonia slip guidelines. \$3.9

Line
No.

1 million was spent to begin initiation of the purchase of 4,000 square feet of
2 waterwall tubes (Exhibit A-12, Schedule B5.1, page 4, line 23). The boiler
3 tubes deteriorate due to combined effect of corrosion fatigue, fireside
4 corrosion, creep damage, and tube thinning. Thirty-seven (37) expansion
5 joints were purchased for \$2.7 million (Exhibit A-12, Schedule B5.1, page
6 4, line 24). The replacements were based on near term failure risk which
7 would affect unit reliability, efficiency, and result in a safety risk to plant
8 personnel. \$2.4 million was spent to procure replacement materials for the
9 south air heater hot and cold end baskets (Exhibit A-12, Schedule B5.1, page
10 4, line 25). The previous baskets had degraded due to corrosion and, if not
11 addressed, would become loose, cause an imbalance and lead to a drivetrain
12 failure. The replacements restored physical integrity and heat transfer
13 efficiency of the air heater. \$1.6 million was spent to procure 10,000 linear
14 feet of tubing for replacement of reheat outlet pendants (Exhibit A-12,
15 Schedule B5.1, page 4, line 26). The tubes were prone to stress-induced
16 precipitation hardening failures and required replacement to ensure reliable
17 operation. \$1.6 million was spent to engineer and procure materials for
18 rebuilding the Unit 1 north and south FGD booster fans (Exhibit A-12,
19 Schedule B5.1, page 4, line 27). Due to the corrosive environment in which
20 these fans operate, the fans require repair or replacement of the hub and
21 blades every eight (8) years to avoid component failures and damage to fan
22 internals. This maintenance was due. Engineering and material
23 procurement continued for \$1.1 million for a 1.5 MW backup generator to
24 be installed in 2023 on the Monroe Unit 1 FGD (Monroe Unit 1 FGD Asset
25 Preservation) (Exhibit A-12, Schedule B5.1, page 4, line 28). The backup

Line
No.

1 generator provides emergency power to allow stabilization of critical FGD
2 equipment during power failures. This backup generator provides dedicated
3 emergency power to the FGD equipment. This project is also detailed in a
4 new report (Exhibit A-12, Schedule B5.1.1) as requested in the Commission
5 Order in Case No. U-21297. The report demonstrates the reasonableness
6 and prudence of the FGD Asset Preservation projects, including the fact that
7 the costs of installing FGD back-up generators now are the same as installing
8 the generators during initial FGD construction 15 years ago, the risks of
9 damage associated with not having back-up generators during a loss of
10 power, and the potential future uses of the generators after the Monroe units
11 retire. Finally, \$1.1 million was spent to start engineering and procurement
12 of materials to replace the existing Monroe Unit 1 coal mill primary air duct
13 and damper (Exhibit A-12, Schedule B5.1, page 4, line 29). The previous
14 ductwork had thinned, allowing fugitive dust leaks, creating fire and other
15 safety risks.

- 16 • 4,000 square feet of Monroe Unit 2 waterwall tubes were replaced for \$16.8
17 million (Exhibit A-12, Schedule B5.1, page 4, line 30). The boiler tubes had
18 deteriorated due to the combined effects of corrosion fatigue, fireside
19 corrosion, creep damage, and tube thinning. Boiler tubes sections were
20 replaced with material that incorporates an Inconel weld overlay protective
21 coating that is resistant to the harsh reducing atmosphere boiler combustion
22 zone conditions. Inconel protective coatings have been utilized for over 10
23 years and have proven extremely well-suited for this application.

Line
No.

- 1 • IP turbine blades were replaced on Monroe Unit 2 for \$4.3 million to
2 eliminate erosion damage on the previous blades (Exhibit A-12, Schedule
3 B5.1, page 5, line 31).
- 4 • Monroe Unit 2 SCR catalyst modules for layers 1, 2, and 4 were replaced for
5 \$4.1 million (Exhibit A-12, Schedule B5.1, page 4, line 32). The catalyst
6 module replacements were required to maintain compliance with air permit
7 emission limits for NOx and ammonia slip guidelines.
- 8 • Monroe Unit 2 coal mill primary air (PA) duct and dampers were replaced
9 for \$3.6 million (Exhibit A-12, Schedule B5.1, page 4, line 33). The
10 previous ductwork had thinned, resulting in fugitive dust leaks.
- 11 • Twenty (20) expansion joints were replaced on Monroe Unit 2 for \$2.7
12 million (Exhibit A-12, Schedule B5.1, page 54, line 34). The replacements
13 were required to maintain unit reliability and efficiency, while also
14 mitigating safety risks to plant personnel.
- 15 • Monroe Unit 2 horizontal reheater tubes (960 linear feet) were replaced for
16 \$2.6 million (Exhibit A-12, Schedule B5.1, page 54, line 35). The horizontal
17 reheater is located within the downdraft section of the boiler. These tubes
18 required replacement to avoid tube failure outages. Tube failures occur from
19 oxygen pitting corrosion, fly ash erosion, abrasive wear of closely spaced
20 horizontal reheater and primary superheater tubes, and the use of soot
21 blowers which operate to remove and prevent ash build-up.
- 22 • \$1.9 million was spent to replace the Unit 2 FGD absorber inlet expansion
23 joint and flanges on both upstream and downstream sides of the joint
24 (Exhibit A-12, Schedule B5.1, page 54, line 36). Flue gas and moisture

Line
No.

1 cause progressive deterioration to the inlet expansion joint necessitating
2 periodic replacement to prevent forced outage failures.

- 3 • The Monroe Unit 2 north and south FGD booster fans were rebuilt for \$1.5
4 million (Exhibit A-12, Schedule B5.1, page 4, line 37). Due to the corrosive
5 environment in which these fans operate, the fans require repair or
6 replacement of the hub and blades every 8 years to avoid risk of a component
7 failure and damage to other fan internals. This maintenance was due.
- 8 • \$1.3 million was spent to complete Monroe Unit 2 DCS and control room
9 modifications (Exhibit A-12, Schedule B5.1, page 4, line 38). The
10 equipment and software were at risk from a reliability perspective, requiring
11 modifications to keep the plant's control systems reliable. The DCS
12 hardware was last replaced over a decade ago and the associated software
13 dates back to the 1980's. Additionally, the equipment was no longer
14 supported by the vendor.
- 15 • Monroe Unit 2 coal mill silo 2-1 (Exhibit A-12, Schedule B5.1, page 4, line
16 41) and silo 2-7 (Exhibit A-12, Schedule B5.1, page 4, line 39) were rebuilt
17 for \$1.2 million each. Monroe Unit 3 coal mill silo 3-5 (Exhibit A-12,
18 Schedule B5.1, page 4, line 45) and silo 3-6 (Exhibit A-12, Schedule B5.1,
19 page 4, line 46) were rebuilt for \$1.2 million and \$1.1 million, respectively.
20 The chemical and abrasive properties of coal within the silos resulted in
21 corrosion and erosion of the silo walls and compromised the structural
22 integrity requiring repairs.
- 23 • \$1.2 million was spent for engineering, material procurement, and
24 preliminary installation work for a 1.5 MW backup generator to be
25 completed in 2023 on Monroe Unit 2 FGD (Monroe Unit 2 FGD Asset

Line
No.

1 Preservation) (Exhibit A-12, Schedule B5.1, page 4, line 40). The backup
2 generator will provide emergency power to allow for stabilization of critical
3 FGD equipment in the event of a power failure. This project is also detailed
4 in a new report (Exhibit A-12, Schedule B5.1.1) as requested in the
5 Commission order in Case No. U-21297. The report demonstrates the
6 reasonableness and prudence of the FGD Asset Preservation projects,
7 including the fact that the costs of installing FGD back-up generators now
8 are the same as installing the generators during initial FGD construction 15
9 years ago, the risks of damage associated with not having back-up generators
10 during a loss of power, and the potential future uses of the generators after
11 Monroe units retire.

- 12 • Monroe Unit 2 FGD mist eliminators (1st and 2nd stages) were replaced for
13 \$1.0 million (Exhibit A-12, Schedule B5.1, page 4, line 42). The original
14 mist eliminator trays were plugged, damaged, and worn. They were replaced
15 to improve FGD moisture removal and emission monitoring equipment
16 reliability and accuracy.
- 17 • SCR catalyst modules for layer 1 on Monroe Unit 3 were replaced for \$3.2
18 million (Exhibit A-12, Schedule B5.1, page 4, line 43). The catalyst module
19 replacements were required to maintain compliance with air permit emission
20 limits for NO_x and ammonia slip guidelines.
- 21 • \$1.6 million was spent to replace the Monroe Unit 3 FGD mist eliminators
22 (1st and 2nd stages) (Exhibit A-12, Schedule B5.1, page 4, line 44). The
23 original mist eliminator trays had become plugged, damaged, and worn.
24 They were replaced to improve FGD moisture removal and emission
25 monitoring equipment reliability and accuracy.

Line
No.

- 1 • The Monroe Unit 4 generator stator rewind was completed for \$2.2 million
- 2 (Exhibit A-12, Schedule B5.1, page 4, line 47). The stator required a rewind
- 3 to maintain the generator's reliability and to address the deterioration of the
- 4 brazed joints and excess coil movement.
- 5 • Procurement of a spare main unit transformer was continued for \$3.9 million
- 6 to replace the transformer that was installed on Monroe Unit 1 in the fall of
- 7 2021 (Exhibit A-12, Schedule B5.1, page 4, line 48). This transformer is
- 8 needed to provide a fleet spare that will be installed in the event of a failure
- 9 of one of the other main unit transformers.
- 10 • Monroe fuel supply tripper car gallery J had the floor replacement (7,199
- 11 square feet of elevated structure) completed for \$4.1 million (Exhibit A-12,
- 12 Schedule B5.1, page 4, line 49). The original tripper gallery floors,
- 13 supporting floor beams, and floor beam top flanges had corroded over time
- 14 and required replacement to ensure worker safety during washdown
- 15 activities required to control fugitive and combustible coal dust. There are
- 16 9 galleries (sections) in the tripper gallery that serve all four Monroe Power
- 17 Plant units, designated by letters A, B, C, D, E, F, G, H, and J. Floor beam
- 18 inspections were conducted to determine the condition of the gallery and
- 19 prioritize sections based on the results. The inspection included the gallery
- 20 conveyor floor system, floor plates, and floor supporting structural steel.
- 21 Gallery J was identified as a priority area in the inspection. Support beams
- 22 and girders show signs of degradation and need to be replaced. This project
- 23 restored the structural integrity of the floor, the floor beams, girders, and
- 24 associated connection hardware for this gallery section.

Line
No.

- 1 • Monroe fuel supply CV-04 transfer chute was replaced for \$2.8 million
- 2 (Exhibit A-12, Schedule B5.1, page 4, line 50). The new discharge chute
- 3 technology minimizes combustible dust and coal spillage.
- 4 • Monroe fuel supply tripper car gallery B started engineering of the floor
- 5 replacement (8,096 square feet of elevated structure) for \$1.3 million
- 6 (Exhibit A-12, Schedule B5.1, page 4, line 51). The original tripper gallery
- 7 floors, supporting floor beams, and floor beam top flanges had corroded over
- 8 time and required replacement to ensure worker safety during washdown
- 9 activities required to control fugitive and combustible coal dust. There are
- 10 nine (9) galleries (sections) in the tripper gallery that serve all four Monroe
- 11 Power Plant units, designated by letters A, B, C, D, E, F, G, H, and J. Floor
- 12 beam inspections were conducted to determine the condition of the gallery
- 13 and prioritize sections based on the results. The inspection included the
- 14 gallery conveyor floor system, floor plates, and floor supporting structural
- 15 steel. Gallery B was identified as a priority area in the inspection. Support
- 16 beams and girders show signs of degradation and need to be replaced. This
- 17 project will restore the structural integrity of the floor, the floor beams,
- 18 girders, and associated connection hardware for this gallery section.
- 19 • The Monroe fuel supply coal pile runoff oil wastewater system began initial
- 20 engineering and material procurement for \$1.1 million (Exhibit A-12,
- 21 Schedule B5.1, page 4, line 52).

22

23 In 2017 the plant experienced a Notice of Violation on a similar system.

24 Remediation of soil and augmentations to the wastewater system were

25 required following the event. Further review of oil-containing equipment on

Line
No.

1 the Monroe property identified the areas around the coal pile run-off system
2 are at risk of a similar event. A major oil spill event into public waterways
3 could result in cleanup costs into the millions as well as fines for not
4 mitigating this potential risk.

5
6 The current coal pile run-off wastewater treatment system has no oil removal
7 capabilities to prevent oil discharges into open waters. The coal pile
8 containment area contains over 30,000 gallons of oil stored in various
9 locations. Any loss of oil from these systems could migrate to the coal pile
10 run-off water collection system.

11
12 Currently, discovery of oil-contaminated water in the coal pile run-off
13 wastewater system requires an operator to be at the right place at the right
14 time. Detecting small quantities of oil sheen is very difficult and heavily
15 influenced by environmental conditions, including daylight, rain, fog, etc.
16 Once the operator discovers that the contamination exists, they manually
17 intervene by deploying oil-containment booms and contracting
18 environmental clean-up firms to mitigate the event.

19
20 The planned project installs an oily waste treatment system that has
21 automated oil removal capabilities for the coal pile run-off system. The new
22 system will not depend on visual observations and manual intervention to
23 trigger an oil clean-up response. Instead, the oily waste treatment systems
24 will provide 24x7 enhanced environmental protection.

Line
No.

1 The detailed discussion above is responsive to the Final Order dated
2 December 1, 2023, in Case No U-21297 in which the Commission indicated
3 support for necessary measures to prevent environmental contamination and
4 damage, but it felt that risk analysis of an environmental spill needed further
5 specificity for this project.

6

7 **Q75. What are the routine projects with projected capital expenditures greater than**
8 **\$1 million planned or completed for 2023 for Steam Power Generation?**

9 A75. Planned or completed 2023 routine capital projects greater than \$1 million are
10 detailed on page 5 of Exhibit A-12, Schedule B5.1 and discussed below.

11

12 • In preparation for the Belle River Unit 2 2024 periodic outage, Belle River
13 Unit 2 LP turbine rotors and blades procurement payments were projected
14 for materials at \$6.1 million (Exhibit A-12, Schedule B5.1, page 5, line 68).
15 Inspections have identified blade erosion and rotor cracking that needs to be
16 addressed to ensure continued safe and reliable operation of the LP turbines.
17 This work is a permanent fix to the issues identified in 2020. Additionally,
18 \$2.3 million was projected to procure materials for the replacement of the
19 Belle River Unit 2 exciter (Exhibit A-12, Schedule B5.1, page 5, line 69).
20 Vibration levels have indicated structural/mechanical integrity issues with
21 the rotor components. Replacement of the exciter will maintain equipment
22 reliability in the future. \$1.5 million was projected to start procurement of
23 materials for the waterwall tubes that will be replaced on Belle River Unit 2
24 in 2024 (Exhibit A-12, Schedule B5.1, page 6, line 70). The project will
25 replace 2,500 square feet of boiler waterwall panels damaged by quench

Line
No.

- 1 cracking and soot blower erosion to support continued reliable boiler
2 operation. Finally, \$1.5 million was projected to procure materials for the
3 Belle River Unit 2 intermediate pressure (IP) turbine valves (Exhibit A-12,
4 Schedule B5.1, page 5, line 71). This project overhauls the four (4) IP
5 turbine stop valves and four (4) control valves. The valves are worn and
6 require overhaul to operate properly. These valves provide overspeed
7 protection for the turbine and prevent possible catastrophic failure.
- 8 • \$3.3 million was projected to finish the separation of St. Clair Power Plant
9 from the Fuel Supply system (Exhibit A-12, Schedule B5.1, page 5, line 72).
10 There are a number of systems in the St. Clair Fuel Supply system that are
11 interrelated with the Belle River Power Plant. Although St. Clair Power
12 Plant retired in 2022, these interrelated systems must remain functional to
13 continue fueling the Belle River Power Plant. The project scope was to
14 completely isolate St. Clair Power Plant from the Fuel Supply System. This
15 scope included fire protection and general service water, wastewater and
16 stormwater, low voltage electrical, and medium voltage electrical
17 switchgear.
- 18 • Installation of a wet dust collector to replace three (3) dry-type dust
19 collectors in the Belle River fuel supply 3TH-9 building was projected for
20 \$1.8 million (Exhibit A-12, Schedule B5.1, page 5, line 73). The prior
21 system had inadequate performance to meet current NFPA guidelines. The
22 replacement mitigates combustible dust and complies with the NFPA
23 combustible dust guidelines.
- 24 • In preparation for the Greenwood Unit 1 2024 periodic outage, \$5.8 million
25 was spent on material progress payments for procurement of the LP turbine

Line
No.

- 1 rotors and blades (Exhibit A-12, Schedule B5.1, page 5, line 74). Stress
- 2 corrosion cracking of multiple blade root connections needs to be addressed
- 3 to ensure continued safe and reliable operation of the LP turbines.
- 4 • Monroe Unit 1 waterwall replacement was completed for \$15.0 million
- 5 (Exhibit A-12, Schedule B5.1, page 5, line 75). The project replaced 4,000
- 6 square feet of boiler waterwall tubes. The boiler tubes were deteriorated due
- 7 to corrosion fatigue combined with fireside corrosion, creep damage, and
- 8 tube thinning.
- 9 • Monroe Unit 1 LP turbine rotors and blades were replaced to address the
- 10 industry-wide safety concern with known stress corrosion cracking for \$10.4
- 11 million (Exhibit A-12, Schedule B5.1, page 5, line 76). Prior inspections
- 12 revealed extensive erosion on the L-0 through L-5 blade rows. These rotors
- 13 will be further analyzed for the severity of stress corrosion cracking and
- 14 refurbished for use on the Monroe Unit 4 LP turbine in 2025 to minimize the
- 15 project cost needed to address stress corrosion cracking on its LP turbine
- 16 forgings.
- 17 • Monroe Unit 1 reheat outlet pendants were replaced for \$5.4 million (Exhibit
- 18 A-12, Schedule B5.1, page 5, line 77). The boiler reheater tubes are critical
- 19 to steam turbine design and operations. Reheater tubes allow exhaust steam
- 20 from the HP turbine to be reheated in the boiler and reintroduced into the IP
- 21 and LP turbines with additional energy that adds to unit MW output at
- 22 improved efficiency levels. The replacements were based on near term tube
- 23 failure risk which would force the unit offline for repair.
- 24 • Thirty-seven (37) expansion joints were replaced on Monroe Unit 1 for \$5.3
- 25 million (Exhibit A-12, Schedule B5.1, page 5, line 78). This project covered

Line
No.

- 1 multiple areas in the air duct and flue gas systems to accommodate thermal
2 expansion of the process ductwork. Scope of work included ash removal to
3 provide a safe workspace, confined space rescue services, scaffold for safe
4 access, lead/asbestos abatement, and replacement of the expansion joints.
5 The replacements were based on near term failure risk which would affect
6 unit reliability, efficiency, and result in a safety risk to plant personnel.
- 7 • \$4.2 million was spent to complete the replacement of the Monroe Unit 1
8 coal mill primary air ductwork (Exhibit A-12, Schedule B5.1, page 5, line
9 79). The previous ductwork had thinned, resulting in fugitive dust leaks, and
10 required replacement.
 - 11 • \$3.9 million was spent to procure and replace blade rows 1, 3, and 8 on the
12 Monroe Unit 1 HP turbine (Exhibit A-12, Schedule B5.1, page 5, line 80).
13 The turbine blades were replaced due to solid particle erosion. The
14 replacement was required to sustain the HP turbine reliability.
 - 15 • Monroe Unit 1 IP turbine blades (Exhibit A-12, Schedule B5.1, page 5, line
16 81) were replaced for \$3.7 million. The turbine blades were replaced due to
17 solid particle erosion. The first stage rows on both ends (turbine-end and
18 generator-end) were replaced. The replacement was required to sustain the
19 IP turbine reliability.
 - 20 • Monroe Unit 1 SCR catalyst modules for layers 1, 2, and 4 were replaced for
21 \$3.3 million (Exhibit A-12, Schedule B5.1, page 5, line 82). The catalyst
22 module replacements were required to maintain compliance with air permit
23 emission limits for NOx and ammonia slip guidelines.
 - 24 • Monroe Unit 1 IP turbine rotor project (Exhibit A-12, Schedule B5.1, page
25 5, line 83) started progress payments of \$2.6 million to replace the rotor in

Line
No.

1 2025. During off-site inspection in 2023, creep void indications of cracking
2 were found in the rotor bore and the stage 1 wheel dovetail roots. The OEM
3 performed the work required to return the IP rotor to service on a short term
4 basis but also provided further analysis of the rotor that confirmed the need
5 to replace the rotor soon, concluding that it could only be safely operated for
6 an additional 30 months.

7 • Monroe Unit 1 economizer tubes were replaced for \$2.5 million (Exhibit A-
8 12, Schedule B5.1, page 5, line 84). The boiler economizers are a critical
9 component of the boiler tubing circuits that removes waste heat from the
10 combustion process and utilizes it to preheat boiler feedwater improving
11 overall cycle efficiency and heat rate. The original equipment economizer
12 had erosion and tube thinning which required approximately 2,000 linear
13 feet of tubing replacements to maintain boiler reliability.

14 • The Monroe Unit 1 reheat turbine stop valves (Exhibit A-12, Schedule B5.1,
15 page 5, line 85), control valves (Exhibit A-12, Schedule B5.1, page 5, line
16 88), and main steam stop valves (Exhibit A-12, Schedule B5.1, page 6, line
17 89) were rebuilt for \$2.4 million, \$1.3 million, and \$1.3 million,
18 respectively. All turbine valves must operate properly to provide overspeed
19 protection for the turbine and prevent possible catastrophic failure.

20 • Monroe Unit 1 SCR inlet and outlet dampers were removed for \$1.5 million
21 (Exhibit A-12, Schedule B5.1, page 5, line 86). When the SCR was
22 originally installed, these dampers and the SCR only operated during
23 summer months. Now, since the SCR is operated year-round due to changes
24 in EPA regulations, the inlet and outlet dampers are not needed and

Line
No.

- 1 contribute to draft losses leading to ID fan limitations, negatively affecting
2 the output capability of the generating unit.
- 3 • The Monroe Unit 1 south air heater hot and cold end baskets were replaced
4 for \$1.4 million (Exhibit A-12, Schedule B5.1, page 5, line 87). The
5 previous baskets were degraded due to corrosion and, if not addressed,
6 would have become loose and cause an imbalance leading to an air heater
7 drivetrain failure. The replacements restored physical integrity and heat
8 transfer efficiency of the air heater.
 - 9 • Monroe Unit 1 coal mill silo 1-3 (Exhibit A-12, Schedule B5.1, page 5, line
10 90) and Monroe Unit 4 coal mill silo 4-1 (Exhibit A-12, Schedule B5.1, page
11 5, line 105) were projected to be rebuilt for \$1.2 million and \$1.5 million,
12 respectively. The chemical and abrasive properties of coal within the silos
13 resulted in corrosion and erosion of the silo walls and compromised the
14 structural integrity requiring repairs.
 - 15 • Monroe Unit 1 turning gear and bull gear were rebuilt for \$1.2 million
16 (Exhibit A-12, Schedule B5.1, page 5, line 91). The turbine turning gear
17 must engage to the bull gear as designed to rotate the turbine shaft properly
18 when the unit is offline to prevent damage to the turbine shaft. To address
19 the excessive wear on these components, the turning gear was overhauled
20 and bull gear was replaced.
 - 21 • Monroe Unit 1 FGD mist eliminators (1st and 2nd stages) were replaced for
22 \$1.1 million (Exhibit A-12, Schedule B5.1, page 5, line 92). The original
23 mist eliminator trays were plugged, damaged, and worn. They were replaced
24 to improve FGD moisture removal and emission monitoring equipment
25 reliability and accuracy.

Line
No.

- 1 • \$1.1 million was spent to replace the Unit 1 FGD absorber inlet expansion
2 joint and flanges on both upstream and downstream sides of the joint
3 (Exhibit A-12, Schedule B5.1, page 5, line 93). The inlet expansion joint is
4 essential for inlet flue gas to reliably enter the absorber tower. It allows for
5 expansion and contraction of the inlet duct with changing temperatures
6 (during a shutdown/startup of the unit). The previous expansion joint was
7 deteriorated and showed visible signs of failure. Failure of this expansion
8 joint will result in flue gas leaking from the ductwork and poses a reliability
9 risk.
- 10 • The Monroe Unit 1 north and south FGD booster fans were rebuilt for \$1.1
11 million (Exhibit A-12, Schedule B5.1, page 5, line 94). The FGD system for
12 each unit includes a north and south booster fan. These axial fans, with a
13 14-foot diameter impeller, are located between the outlet of the precipitator
14 and the inlet to the FGD Absorber. Failure of one of these booster fans
15 would cause the unit to be limited to half load until replacement parts could
16 be procured and installed. Due to the corrosive environment in which these
17 fans operate, the fans require repair or replacement of the hub and blades
18 every 8 years to maintain reliability. This maintenance was due in 2023.
- 19 • \$1.2 million was spent to start procurement of materials in preparation to
20 replace the Monroe Unit 2 air heater cold end baskets (Exhibit A-12,
21 Schedule B5.1, page 5, line 95) in 2024. The air heater plays a critical heat
22 transfer role to boiler efficiency and flue gas equipment operational
23 performance. The Monroe units cold end baskets typically last 7-10 years.
24 The cold-end baskets on Monroe Unit 2 north and south air heaters have
25 been in service since 2014 and are currently in failure mode due to a

Line
No.

- 1 significant loss (30 percent) of element material. As this condition
2 progresses, so does the risk of an out of balance condition, placing high
3 stresses on all components of the air heater. The imbalance issue will lead
4 to drive train failures, resulting in unit forced outages.
- 5 • In preparation for the Monroe Unit 3 outage in 2024, new air heater cold end
6 baskets were purchased for \$2.2 million (Exhibit A-12, Schedule B5.1, page
7 5, line 96). The cold-end baskets on Monroe Unit 3 north and south air
8 heaters have been in service since 2015 and are currently in failure mode due
9 to a significant loss (30 percent) of element material. Additionally, the
10 purchase of SCR catalyst modules for layers 2, 3, and 4 are projected for
11 \$1.5 million (Exhibit A-12, Schedule B5.1, page 5, line 97). The catalyst
12 module replacements are required to maintain compliance with air permit
13 emission limits for NOx and ammonia slip guidelines. \$1.3 million was
14 projected to start engineering and procure material to replace twelve (12)
15 Monroe Unit 3 expansion joints (Exhibit A-12, Schedule B5.1, page 5, line
16 98). The replacements are required to maintain unit reliability and
17 efficiency, while also mitigating safety risks to plant personnel. Finally, \$1.1
18 million was projected to be spent to start engineering and begin to procure
19 materials to replace the Monroe Unit 3 existing coal mill primary air
20 ductwork (Exhibit A-12, Schedule B5.1, page 5, line 99). The existing
21 ductwork is thinning, causing fugitive dust leaks, and requires replacement.
 - 22 • Monroe Unit 3 coal mill 3-6 overhaul was projected for \$1.0 million. The
23 coal mill overhaul was due to service hours, air flow performance, and lube
24 oil analysis indications of deteriorating internal components (Exhibit A-12,
25 Schedule B5.1, page 5, line 100). Due to the abrasiveness of coal, coal mill

Line
No.

1 parts experience significant wear in the process of converting lump coal to a
2 fine powder consistency suitable for boiler combustion and need to be
3 disassembled, repaired, and components replaced approximately every 10
4 years.

5 • In preparation for the Monroe Unit 4 2025 periodic outage, \$4.3 million was
6 spent to start procurement of long lead materials related to refurbishment of
7 the LP turbines (Exhibit A-12, Schedule B5.1, page 5, line 101).
8 Refurbishment is needed due to the industry-wide problem of stress
9 corrosion cracking on the current LP turbine. The rotors being replaced on
10 Monroe Unit 1 in 2023 will be analyzed, refurbished, and installed on
11 Monroe Unit 4 to keep the project cost to a minimum while mitigating the
12 safety risk of a stress corrosion cracking catastrophic failure.

13 • Installation of SCR catalyst modules for layer 2 for Monroe Unit 4 was
14 projected to cost \$2.1 million (Exhibit A-12, Schedule B5.1, page 5, line
15 102). The catalyst module replacements are required to maintain compliance
16 with air permit emission limits for NOx and ammonia slip guidelines.

17 • Monroe Unit 4 south boiler feed pump turbine condenser retubing was
18 projected to cost \$1.8 million (Exhibit A-12, Schedule B5.1, page 5, line
19 103). A significant increase in tube failures in the inlet section of the
20 condenser were identified resulting in thirty-nine (39) percent of the
21 condenser inlet section tubes being plugged, requiring the condenser to be
22 retubed to keep the boiler feed pump turbine in service.

23 • In preparation for the Monroe Unit 4 outage in 2025, \$1.5 million was
24 projected to be spent to start engineering and material procurement of SCR
25 catalyst module layers 1, 3, and 4 that will be replaced (Exhibit A-12,

Line
No.

- 1 Schedule B5.1, page 5, line 104). The catalyst module replacements are
2 required to maintain compliance with air permit emission limits for NOx and
3 ammonia slip guidelines.
- 4 • Procurement of a spare main unit transformer was completed for \$3.0
5 million to replace the transformer that was installed on Monroe Unit 1 in the
6 fall of 2021 (Exhibit A-12, Schedule B5.1, page 5, line 106). This
7 transformer is needed for fleet reliability in the event of a failure of one of
8 the other main unit transformers.
 - 9 • Monroe underground storage tank No. 389 (Exhibit A-12, Schedule B5.1,
10 page 5, line 107) will be removed and replaced with an above ground storage
11 tank for a projected \$2.0 million. The tank collects used oil, is constructed
12 of double-walled steel, has a capacity of 5,750 gallons and has been in
13 service since 1993. This project will mitigate the oil spill risk and ensure
14 continued environmental compliance.
 - 15 • The Monroe fuel supply coal pile runoff oil wastewater system replacement
16 project was projected to continue with construction at a cost of \$4.6 million
17 (Exhibit A-12, Schedule B5.1, page 5, line 108). As previously discussed
18 above in the 2022 steam routine projects section, this project enhances
19 environmental compliance by reducing the risk of oil contaminants from the
20 storm water and coal pile run-off systems reaching the lake.
 - 21 • Monroe fuel supply tripper car gallery B floor replacement (8,096 square
22 feet of elevated structure) was completed for \$3.0 million (Exhibit A-12,
23 Schedule B5.1, page 5, line 109). The original tripper gallery floors,
24 supporting floor beams, and floor beam top flanges had corroded over time
25 and required replacement to ensure worker safety during washdown

Line
No.

- 1 activities required to control fugitive and combustible coal dust. There are
2 9 galleries (sections) in the tripper gallery that serve all four Monroe Power
3 Plant units, designated by letters A, B, C, D, E, F, G, H, and J. Floor beam
4 inspections were conducted to determine the condition of the gallery and
5 prioritize sections based on the results. The inspection included the gallery
6 conveyor floor system, floor plates, and floor supporting structural steel.
7 Gallery B was identified as a priority area in the inspection. Support beams
8 and girders showed signs of degradation and needed to be replaced. This
9 project restored the structural integrity of the floor, the floor beams, girders,
10 and associated connection hardware for this gallery section.
- 11 • Monroe fuel supply transfer chute that feeds from conveyor C4 to conveyors
12 C5 and C5A was projected to be replaced for \$2.7 million (Exhibit A-12,
13 Schedule B5.1, page 5, line 110), the transfer chutes from conveyors C10,
14 C11, and C5 that feed onto conveyor C4 were replaced for \$2.0 million
15 (Exhibit A-12, Schedule B5.1, page 5, line 111), and transfer chute from
16 conveyor C19 that feeds onto conveyor C10 was projected to be replaced for
17 \$1.5 million (Exhibit A-12, Schedule B5.1, page 5, line 113). Transfer
18 chutes are used throughout the fuel supply system to direct coal from one
19 conveyor belt to another on the path from the coal piles to the powerhouse.
20 The previous chute tended to generate significant amounts of coal dust
21 during periods of dry coal and was prone to pluggage during periods of wet
22 coal. The new discharge chute technology minimizes combustible dust and
23 coal spillage and ensures compliance with NFPA guidelines.
 - 24 • In preparation for the Monroe fuel supply tripper car gallery C floor (Exhibit
25 A-12, Schedule B5.1, page 5, line 112) being replaced in 2024, \$1.7 million

Line
No.

1 was spent for engineering and materials (10,750 square feet of elevated
2 structure). The original tripper gallery floor, supporting floor beams, and
3 floor beam top flanges have corroded over time and require replacement to
4 ensure worker safety during washdown activities required to control fugitive
5 and combustible coal dust. There are 9 galleries (sections) in the tripper
6 gallery that serve all four Monroe Power Plant units, designated by letters A,
7 B, C, D, E, F, G, H, and J. Floor beam inspections were conducted to
8 determine the condition of the gallery and prioritize sections based on the
9 results. The inspection included the gallery conveyor floor system, floor
10 plates, and floor supporting structural steel. Gallery C was identified as the
11 next priority area in the inspection. Support beams and girders show signs
12 of degradation and need to be replaced. This project will restore the
13 structural integrity of the floor, the floor beams, girders, and associated
14 connection hardware for this gallery section.

- 15 • The capping of section 1a at Sibley Quarry was projected for \$9.6 million
16 (Exhibit A-12, Schedule B5.1, page 5, line 126). This portion of the site,
17 twenty-seven (27) acres, has reached its licensed capacity and requires
18 capping per its landfill operating permit.

19

20 **Q76. What are the routine projects with projected capital expenditures greater than**
21 **\$1 million planned for 2024 for Steam Power Generation?**

22 A76. Planned routine capital projects greater than \$1 million for 2024 are detailed on
23 page 6 of Exhibit A-12, Schedule B5.1 and discussed below.

- 24 • In preparation for the 2025 periodic outage on Belle River Unit 1,
25 engineering and material procurement will be initiated to replace sixty-seven

Line
No.

- 1 (67) 480-volt breakers (Exhibit A-12, Schedule B5.1, page 6, line 128) and
2 fifty-three (53) medium voltage breakers (Exhibit A-12, Schedule B5.1,
3 page 6, line 129) for \$2.0 million and \$1.9 million, respectively. The
4 breakers are original to the 1980's era unit and the reliable operation of these
5 breakers is at risk due to their age. These breakers are obsolete and no longer
6 supported by the OEM. Additionally, these breakers are an electrical safety
7 concern due to the obsolete trip device technology. Finally, \$1.3 million will
8 be spent to start material procurement for the Belle River Unit 1 east boiler
9 feed pump turbine blades and rotor (Exhibit A-12, Schedule B5.1, page 6,
10 line 130). During the 2022 Belle River Unit 1 periodic outage, the east boiler
11 feed pump turbine rotor was inspected, and heavy rubbing was found on
12 multiple stages where the blades connect to the rotor steeples. Crack
13 indications were found and removed as a temporary repair, enabling the
14 equipment to return to service with a plan for replacement during the 2025
15 periodic outage.
- 16 • \$1.1 million will be spent to rebuild the white coal mill on Belle River Unit
17 1 due to service hours and lube oil analysis indications of deteriorating
18 internal components (Exhibit A-12, Schedule B5.1, page 6, line 131). Due
19 to the abrasiveness of coal, coal mill parts experience significant wear in the
20 process of converting lump coal to a fine powder consistency suitable for
21 boiler combustion and need to be disassembled, repaired, and components
22 replaced approximately every 10 years. The coal mill was last overhauled
23 in 2014 and has close to 50,000 run hours.
 - 24 • The Belle River Unit 2 LP turbine rotors and blades will be replaced for \$6.4
25 million (Exhibit A-12, Schedule B5.1, page 6, line 132). Inspections have

Line
No.

1 identified blade erosion and rotor cracking that needs to be addressed to
2 ensure continued safe and reliable operation of the LP turbines. This work
3 is a permanent fix to the issues identified and repaired on a temporary basis
4 in 2020.

5 • Waterwall tubes will be replaced on Belle River Unit 2 for \$4.3 million
6 (Exhibit A-12, Schedule B5.1, page 6, line 133) to support continued reliable
7 boiler operation. The project will replace 2,500 square feet of boiler
8 waterwall panels damaged by quench cracking and soot blower erosion.

9 • \$3.3 million will be spent to replace the Belle River Unit 2 exciter with a
10 static exciter (Exhibit A-12, Schedule B5.1, page 6, line 134). Vibration
11 levels have indicated structural and mechanical integrity issues with the rotor
12 components. Replacement of the exciter will maintain equipment reliability
13 in the future.

14 • Belle River Unit 2 IP turbine valves will be overhauled for \$2.8 million
15 (Exhibit A-12, Schedule B5.1, page 6, line 135). This project overhauls the
16 four (4) IP turbine stop valves and four (4) control valves. The valves are
17 worn and require overhaul to operate properly. These valves provide
18 overspeed protection for the turbine and prevent possible catastrophic
19 failure.

20 • The Belle River Unit 2 turbine stop valve actuators will be replaced for \$2.7
21 million (Exhibit A-12, Schedule B5.1, page 6, line 136). The original
22 actuators provided by the OEM have been replaced across the industry due
23 to maintenance issues, lack of spare parts, and an absence of qualified
24 companies capable of repairing them. The replacements are required to
25 maintain continued reliable operation of this system that controls turbine

Line
No.

- 1 loading. Failure of these valves to properly operate would impact the ability
2 to properly control unit output. These valves also provide overspeed
3 protection for the turbine and prevent possible catastrophic failure.
- 4 • In preparation for the 2026 periodic outage on Belle River Unit 2,
5 engineering and material procurement will be initiated to replace sixty-seven
6 (67) 480-volt breakers (Exhibit A-12, Schedule B5.1, page 6, line 137) and
7 fifty-three (53) medium voltage breakers (Exhibit A-12, Schedule B5.1,
8 page 6, line 138) for \$2.0 million and \$1.8 million, respectively. The
9 breakers are original to the 1980's era unit. The reliable operation of these
10 breakers is at risk due to their age. These breakers are obsolete and no longer
11 supported by the OEM. Additionally, these breakers are an electrical safety
12 concern due to the obsolete trip device technology.
 - 13 • Over 400 primary superheater tube bends will be replaced on Belle River
14 Unit 2 for \$1.7 million (Exhibit A-12, Schedule B5.1, page 6, line 139). The
15 tubes have been compromised from soot blower erosion and require
16 replacement to support continued reliable boiler operations.
 - 17 • In preparation for dual-unit outages in 2025 and 2026 at Belle River Power
18 Plant, engineering and material procurement will be initiated to replace
19 ninety-four (94) common system 480-volt breakers (Exhibit A-12, Schedule
20 B5.1, page 6, line 140) and fifty-seven (57) common system medium voltage
21 breakers (Exhibit A-12, Schedule B5.1, page 6, line 141) for \$2.7 million
22 and \$2.0 million, respectively. The breakers are original to the 1980's era
23 units. The reliable operation of these breakers is at risk due to their age.
24 These breakers are obsolete and no longer supported by the OEM.

Line
No.

- 1 Additionally, these breakers are an electrical safety concern due to the
- 2 obsolete trip device technology.
- 3 • Underground storage tanks No. 387 and No. 388 (Exhibit A-12, Schedule
- 4 B5.1, page 6, line 142) at Belle River Power Plant will be replaced for \$1.9
- 5 million. The tanks have been in service for over 29 years. Underground
- 6 storage tanks that have been in service for this many years have an increased
- 7 risk of failure, potentially allowing the contents to leak, contaminating the
- 8 soil and groundwater around the tank. Tank No. 387 contains gasoline fuel
- 9 with a capacity of 4,000 gallons. Tank No. 388 contains diesel fuel with a
- 10 capacity of 1,000 gallons. Additionally, underground storage tank No. 393
- 11 (Exhibit A-12, Schedule B5.1, page 6, line 143) will be replaced for \$1.8
- 12 million. The tank contains used oil with a capacity of 2,300 gallons and has
- 13 also been in service for over 29 years.
- 14 • \$12.1 million will be spent on engineering and material procurement for the
- 15 Greenwood Unit 1 LP turbine rotors and blades replacement project (Exhibit
- 16 A-12, Schedule B5.1, page 6, line 148). Stress corrosion cracking of
- 17 multiple blade root connections is being addressed to ensure continued safe
- 18 and reliable operation of the LP turbines.
- 19 • Materials will be procured for the 2025 replacement of the Greenwood Unit
- 20 1 feedwater heater No. 6 (Exhibit A-12, Schedule B5.1, page 6, line 149)
- 21 and feedwater heater No. 3 (Exhibit A-12, Schedule B5.1, page 6, line 150)
- 22 for \$1.6 million and \$1.4 million, respectively. A leak in the shell of
- 23 feedwater heater No. 6 was discovered in March 2023. Phased Array
- 24 Ultrasonic Testing (PAUT) also identified an 8” long crack in the shell.
- 25 Further PAUT testing found several smaller connected indications on the

Line
No.

- 1 inside diameter of the shell. Additional borescope inspection revealed
2 multiple internal weld cracks located between the desuperheating zone and
3 the drain cooling zone of the feedwater heater. Feedwater heater No. 6
4 needs to be replaced to restore reliable service. The existing feedwater
5 heater No. 3 is experiencing an increasing number of tube leaks and requires
6 replacement to restore reliability. Both feedwater heaters take waste heat
7 from the LP turbines and use it to preheat boiler feedwater, improving the
8 overall efficiency of the steam power cycle. Steam turbine power cycles
9 utilize feedwater heating in this manner.
- 10 • \$1.5 million will be spent on Monroe Unit 1 to start material procurement
11 for the SCR catalyst modules being replaced on layer 3 in 2025 (Exhibit A-
12 12, Schedule B5.1, page 6, line 151). The catalyst module replacements are
13 required to maintain compliance with air permit emission limits for NOx
14 and ammonia slip guidelines.
 - 15 • For the Monroe Unit 1 IP turbine rotor (Exhibit A-12, Schedule B5.1, page
16 6, line 152), the Company will continue progress payments of \$1.1 million
17 to replace the rotor in 2025. During an offsite inspection in 2023, creep
18 void indications of cracking were found in the bore and the stage 1 wheel
19 dovetail roots. The OEM performed the work required to return the unit to
20 service on a short-term basis but also provided further analysis of the rotor
21 that confirmed the need to replace the rotor soon, concluding that it could
22 only be returned to service for no more than 30 months.
 - 23 • In preparation for the Monroe Unit 2 periodic outage in 2026, \$8.3 million
24 will be spent to start procurement of material to forge new LP turbine rotors
25 and blades (Exhibit A-12, Schedule B5.1, page 6, line 153). Replacement

Line
No.

- 1 is needed due to the industry-wide problem of stress corrosion cracking on
2 the current LP turbine forgings.
- 3 • \$4.2 million will be spent to complete the replacement of the Monroe Unit
4 2 north & south air heater cold end baskets (Exhibit A-12, Schedule B5.1,
5 page 6, line 154). The air heater plays a critical heat transfer role to boiler
6 efficiency and flue gas equipment operational performance. The Monroe
7 cold end baskets typically last 7-10 years. The cold-end baskets on Monroe
8 Unit 2 north and south air heaters have been in service since 2014 and are
9 currently in failure mode due to a significant loss (30 percent) of element
10 material. As this condition progresses, so does the risk of an out of balance
11 condition, placing high stresses on all components of the air heater. The
12 imbalance issue will lead to drive train failures, resulting in unit forced
13 outages.
 - 14 • \$3.0 million will be spent on Monroe Unit 2 to complete the replacement of
15 layer 3 SCR catalyst modules (Exhibit A-12, Schedule B5.1, page 6, line
16 155). The catalyst module replacements are required to maintain
17 compliance with air permit emission limits for NOx and ammonia slip
18 guidelines.
 - 19 • Monroe Unit 2 coal mill feeder controls will be replaced for \$1.5 million
20 (Exhibit A-12, Schedule B5.1, page 6, line 156). The current coal mill
21 feeder controls for all seven (7) coal mills are original equipment (1970's).
22 Reliability of this equipment has diminished, causing unit derates.
23 Replacing the obsolete controls is needed to address the reliability issues.
24 This controls project upgrade will improve reliability, accuracy of
25 measuring coal flow, and boiler efficiency.

Line
No.

- 1 • \$12.7 million will be spent to replace Monroe Unit 3 waterwall tubes
2 (Exhibit A-12, Schedule B5.1, page 6, line 157). This project was reduced
3 in scope based on the advanced unit retirement as previously discussed in
4 Q70. The project will now only replace approximately 2,000 square feet of
5 boiler waterwall tubes. In total, the waterwall section of a single Monroe
6 unit consists of over 42,000 square feet of tubes joined together in the
7 furnace area of the boiler. The waterwall tubes absorb heat from the
8 combustion process to convert boiler water to steam, the basic process of
9 the steam power cycle. A tube leak in any portion of the waterwall requires
10 the unit to be removed from service for repair. The boiler tubes being
11 replaced are deteriorating due to corrosion fatigue combined with fireside
12 corrosion, creep damage, and tube thinning.
- 13 • Replacement of the SCR catalyst modules for layers 1, 2, and 3 on Monroe
14 Unit 3 will be completed for \$6.7 million (Exhibit A-12, Schedule B5.1,
15 page 6, line 158). The catalyst module replacements are required to
16 maintain compliance with air permit emission limits for NOx and ammonia
17 slip guidelines.
- 18 • \$5.3 million will be spent to complete the replacement of the existing
19 Monroe Unit 3 coal mill primary air (PA) ductwork (Exhibit A-12, Schedule
20 B5.1, page 6, line 159). The existing ductwork is thinning, resulting in
21 fugitive dust leaks, and requires replacement. This project scope includes
22 removal and replacement of the interconnecting ductwork, slide gates,
23 dampers, and expansion joints on the unit's seven coal mills.
- 24 • \$5.0 million will be spent to overhaul the Monroe Unit 3 turbine valves
25 (Exhibit A-12, Schedule B5.1, page 6, line 160). Project scope includes the

Line
No.

- 1 four (4) throttle valves, four (4) intercept valves, eight (8) governor valves,
2 and two (2) reheat stop valves. The valves are worn and require overhaul
3 to ensure proper operation until unit retirement. These valves provide
4 overspeed protection for the turbine and prevent possible catastrophic
5 failure.
- 6 • \$4.3 million will be spent to complete the replacement of Monroe Unit 3 IP
7 turbine blades to correct erosion damage on the existing blades (Exhibit A-
8 12, Schedule B5.1, page 6, line 161).
 - 9 • Twelve (12) Monroe Unit 3 expansion joints will be replaced for \$3.3
10 million due to leakage or being at risk of near-term leaking (Exhibit A-12,
11 Schedule B5.1, page 6, line 162). This project covers multiple areas in the
12 air duct/flue gas systems to provide a means of thermal expansion of the
13 process ductwork. Scope of work includes vacuuming of all areas to
14 provide a safe workspace, confined space rescue services, scaffold for safe
15 access, lead/asbestos abatement, and replacement of the expansion joints.
16 The replacements are based on near term failure risk which would affect
17 unit reliability, efficiency, and result in a safety risk to plant personnel.
 - 18 • Monroe Unit 3 reheat outlet pendants will be replaced for \$2.7 million
19 (Exhibit A-12, Schedule B5.1, page 6, line 163). The boiler reheater tubes
20 are critical to steam turbine design and operations. Reheater tubes allow
21 exhaust steam from the HP turbine to be reheated in the boiler and
22 reintroduced into the IP and LP turbines with additional energy that adds to
23 unit MW output at improved efficiency levels. The replacements are based
24 on near term tube failure risk which would force the unit offline for repair.

Line
No.

- 1 • \$2.7 million will be spent to complete the replacement of the Monroe Unit
2 3 north & south air heater cold end baskets (Exhibit A-12, Schedule B5.1,
3 page 6, line 164). The baskets are in failure mode with significant loss (30
4 percent) of element material. The baskets have been in service since 2015,
5 having a 7-10 year life. The integrity, reliability, and efficiency of the
6 Monroe Unit 3 north & south air heater cold-end baskets will be restored.
- 7 • Monroe Unit 3 horizontal reheater tubes (4,000 linear feet) will be replaced
8 for \$2.6 million (Exhibit A-12, Schedule B5.1, page 6, line 165). The
9 horizontal reheater is located within the downdraft section of the boiler.
10 These tubes require replacement to avoid tube failure outages. Tube failures
11 occur from oxygen pitting corrosion, fly ash erosion, abrasive wear of
12 closely spaced horizontal reheater and primary superheater tubes, and the
13 use of sootblowers which operate to remove/prevent ash build-up.
- 14 • \$2.6 million will be spent to complete the Monroe Unit 3 DCS and control
15 room modifications (Exhibit A-12, Schedule B5.1, page 6, line 166). The
16 equipment and software are at risk from a reliability perspective, requiring
17 modifications to keep the plant's control systems reliable. The DCS
18 hardware was last replaced over a decade ago and the associated software
19 dates back to the 1980's. Additionally, the equipment is no longer
20 supported by the vendor. As discussed in the preceding section, the
21 Company has scaled back this project to focus on the critical work necessary
22 to support continued operations to 2028.
- 23 • \$2.4 million will be spent to replace the upper and lower bearings on
24 Monroe Unit 3 coal mill classifiers (Exhibit A-12, Schedule B5.1, page 6,
25 line 167). The rebuild cycle for the classifiers is based on bearing life

Line
No.

- 1 expectancy, OEM recommendations, and condition of the internal wear
- 2 components. The classifier bearings are recommended for replacement
- 3 every 10 years, and the Monroe Unit 3 bearings have been in service since
- 4 2015.
- 5 • Monroe Unit 3 coal mill 3-7 silo will be rebuilt for \$1.5 million (Exhibit A-
- 6 12, Schedule B5.1, page 6, line 168). The chemical and abrasive properties
- 7 of coal within the silos resulted in corrosion and erosion of the silo walls
- 8 creating coal leaks and compromised the structural integrity. Repairs are
- 9 required for a safe workspace and continued reliable operation.
- 10 • In preparation for the Monroe Unit 4 2025 periodic outage, \$6.0 million will
- 11 be spent to start procurement of long lead materials related to refurbishment
- 12 of the LP turbines (Exhibit A-12, Schedule B5.1, page 6, line 169).
- 13 Refurbishment is needed due to the industry-wide problem of stress
- 14 corrosion cracking on the current LP turbine which could result in
- 15 unexpected catastrophic failure. The LP rotors that were installed on
- 16 Monroe Unit 1 in 2001 have been replaced with new upgraded rotors in
- 17 2023. Due to the cost of forging new rotors or the extended outage required
- 18 to perform the refurbishment of the Monroe Unit 4 rotors, Unit 4's rotors
- 19 will be replaced with those that were removed from Unit 1. The Unit 1
- 20 rotors will be inspected and refurbished to provide safe and reliable
- 21 operation of the Unit 4 LP turbines until the projected retirement of Unit 4
- 22 in 2028. In addition, SCR catalyst modules for layers 1, 3, and 4 will be
- 23 purchased for \$3.8 million (Exhibit A-12, Schedule B5.1, page 6, line 170).
- 24 The catalyst module replacements are required to maintain compliance with
- 25 air permit emission limits for NOx and ammonia slip guidelines. \$1.8

Line
No.

- 1 million will be spent to start engineering and begin to procure materials to
2 replace the Monroe Unit 4 existing coal mill primary air ductwork (Exhibit
3 A-12, Schedule B5.1, page 6, line 171). The existing ductwork is thinning,
4 resulting in fugitive dust leaks, and requires replacement. \$1.4 million will
5 be spent to procure materials for Monroe Unit 4 expansion joints to be
6 replaced in 2025 (Exhibit A-12, Schedule B5.1, page 6, line 172). Fourteen
7 (14) high priority Monroe Unit 4 expansion joints have been identified to
8 be replaced due to leakage. A leak can affect unit reliability and efficiency,
9 and result in a safety risk to plant personnel. Finally, \$1.2 million will be
10 spent to procure materials for the Monroe Unit 4 turbine valves project
11 (Exhibit A-12, Schedule B5.1, page 6, line 173). Project scope includes the
12 four (4) stop valves, four (4) control valves, and 2 combined reheat stop
13 valves. The valves are worn and require overhaul for proper operation until
14 the projected Unit 4 retirement. These valves provide overspeed protection
15 for the turbine and prevent possible catastrophic failure.
- 16 • Monroe underground storage tank No. 389 (Exhibit A-12, Schedule B5.1,
17 page 6, line 174) will be replaced with an above ground storage tank for
18 \$1.2 million. Tank No. 389 has been in service since 1993. The tank
19 collects used oil and is constructed of double-walled steel. Tank No. 389
20 has a capacity of 5,750 gallons. This project will mitigate the oil spill risk
21 and ensure continued environmental compliance.
 - 22 • Monroe fuel supply tripper car gallery C will have the floor replacement
23 (10,750 square feet of elevated structure) completed for \$4.7 million
24 (Exhibit A-12, Schedule B5.1, page 6, line 175). The original tripper gallery
25 floor, supporting floor beams, and floor beam top flanges have corroded

Line
No.

- 1 over time and require replacement to ensure worker safety during
2 washdown activities required to control fugitive and combustible coal dust.
3 There are 9 galleries (sections) in the tripper gallery that serve all four
4 Monroe Power Plant units, designated by letters A, B, C, D, E, F, G, H, and
5 J. Floor beam inspections were conducted to determine the condition of the
6 gallery and prioritize sections based on the results. The inspection included
7 the gallery conveyor floor system, floor plates, and floor supporting
8 structural steel. Gallery C was identified as the next priority area in the
9 inspection. Support beams and girders show signs of degradation and need
10 to be replaced. This project will restore the structural integrity of the floor,
11 the floor beams, girders, and associated connection hardware for this gallery
12 section.
- 13 • \$3.0 million will be spent in Monroe fuel supply to replace the transfer
14 chutes in the CV-C2 Loading Zone (Exhibit A-12, Schedule B5.1, page 6,
15 line 176). The CV-C2 loading zone transfer chutes design and technology
16 is obsolete. This project replaces three (3) transfer chutes (C1A to CV-C2,
17 C1B to CV-C2 & C1C to CV-C2) that load onto CV-C2 so that the transfer
18 point is reconfigured such that the coal stream is less susceptible to dust
19 generation, pluggage, and spillage.
 - 20 • The Monroe fuel supply coal pile runoff oil wastewater system replacement
21 project will be completed for \$2.6 million (Exhibit A-12, Schedule B5.1,
22 page 6, line 177). As previously discussed above in the 2022 steam routine
23 projects section, this project enhances environmental compliance by
24 reducing the risk of oil contaminants from the storm water and coal pile run-
25 off systems reaching the lake.

Line
No.

- 1 • The capping of section 1A at Sibley Quarry will be completed for \$8.3
2 million (Exhibit A-12, Schedule B5.1, page 6, line 186). This portion of the
3 site, twenty-seven (27) acres, has reached its licensed capacity and requires
4 capping as it is no longer available for material disposal.

5

6 **Q77. What are the routine projects with projected capital expenditures greater than**
7 **\$1 million to be executed in 2025 for Steam Power Generation?**

8 A77. Planned maintenance projects greater than \$1 million in 2025 are detailed on page
9 7 of Exhibit A-12, Schedule B5.1 and discussed below.

- 10 • \$6.3 million will be spent on Belle River Unit 1 to complete replacement of
11 waterwall tubes (Exhibit A-12, Schedule B5.1, page 7, line 188). The project
12 will replace 2,500 square feet of boiler waterwall panels damaged by quench
13 cracking and sootblower erosion to support continued reliable boiler
14 operation.
- 15 • \$5.3 million will be spent to replace baskets on Belle River Unit 1 secondary
16 air heater (Exhibit A-12, Schedule B5.1, page 7, line 189). The baskets of
17 the secondary air heaters have been in service for 10 years, have eroded, are
18 loose and at risk of falling out, causing a forced outage. The integrity,
19 reliability, and efficiency of the secondary air heater baskets will be restored
20 with this project.
- 21 • Belle River Unit 1 IP turbine valves (Exhibit A-12, Schedule B5.1, page 7,
22 line 190) will be overhauled for \$4.5 million. The four (4) IP turbine control
23 and four (4) stop valves begin to wear within 6 to 8 years of an overhaul and
24 must be disassembled, inspected, and repaired every other periodic
25 outage. The Unit 1 IP turbine control and stop valves need to operate

Line
No.

1 properly to provide overspeed protection for the turbine and prevent possible
2 catastrophic failure.

3 • \$3.3 million will be spent to replace the Belle River Unit 1 duplex heater
4 (No. 1 and No. 2 low-pressure feedwater heater) (Exhibit A-12, Schedule
5 B5.1, page 7, line 191). The low-pressure heaters are original plant
6 equipment. Eddy current testing and borescope inspections of these heaters
7 identified tube wall loss damage at the support plates. Replacement of the
8 duplex heater is required to maintain unit performance.

9 • \$2.6 million will be spent to replace Belle River Unit 1 expansion joints
10 (Exhibit A-12, Schedule B5.1, page 7, line 192). This project replaces
11 sixteen (16) expansion joints on the air side of the ductwork going to the
12 boiler and on the gas side of the ductwork from the boiler. A comprehensive
13 plan to identify and replace expansion joints on the air and gas ducts was
14 developed and is being implemented to address leakage. The replacements
15 are based on near term failure risk which would affect unit reliability,
16 efficiency, and result in a safety risk to plant personnel.

17 • 792 linear feet of Belle River Unit 1 horizontal middle reheat tubes (Exhibit
18 A-12, Schedule B5.1, page 7, line 193) will be replaced for \$2.2 million.
19 Corrosion and sootblower erosion have degraded the original 1980's era
20 factory tube welds in the horizontal middle reheater.

21 • \$2.4 million will be spent to complete the replacement of the Belle River
22 Unit 1 east boiler feed pump turbine blades and rotor (Exhibit A-12,
23 Schedule B5.1, page 7, line 194). During Belle River Unit 1's 2022 periodic
24 outage, the east boiler feed pump turbine rotor was inspected and heavy
25 rubbing was found on multiple stages where the blades connect to the rotor

Line
No.

- 1 steeples. Crack indications were found and removed as a temporary repair
2 enabling the equipment to return to service with a plan for replacement
3 during the 2025 periodic outage.
- 4 • \$5.0 million will be spent to cap 16 acres in Area G2 – Phase 2 at the Range
5 Road Landfill with a 2-foot clay cover and a 6-inch layer of friable earth
6 with vegetation cover (Exhibit A-12, Schedule B5.1, page 7, line 195). This
7 work complies with the site landfill license from EGLE which requires
8 sections of the landfill be capped as they are filled.
 - 9 • Engineering and material procurement will continue for the replacement of
10 the Belle River north auxiliary boiler (Exhibit A-12, Schedule B5.1, page 7,
11 line 196) and Belle River south auxiliary boiler (Exhibit A-12, Schedule
12 B5.1, page 7, line 197) for \$1.9 million each. Both auxiliary boilers are
13 original to the 1980's era plant. They have become unreliable due to
14 frequent tube leaks, resulting in multiple tubes being plugged which
15 significantly reduces boiler efficiency. As boiler efficiency is reduced, there
16 is an increasing risk that the boilers will not provide sufficient steam for unit
17 startups or building heat. Without sufficient building heat, there will be
18 freezing damage to various plant systems and equipment and safety issues
19 for plant personnel.
 - 20 • \$5.9 million will be spent to complete the Greenwood Unit 1 LP turbine
21 rotors and blades replacement project (Exhibit A-12, Schedule B5.1, page 7,
22 line 201). Stress corrosion cracking of multiple blade root connections is
23 being addressed to ensure continued safe and reliable operation of the LP
24 turbines.

Line
No.

- 1 • Greenwood Unit 1 feedwater heater No. 6 (Exhibit A-12, Schedule B5.1,
2 page 7, line 202) and feedwater heater No. 3 (Exhibit A-12, Schedule B5.1,
3 page 7, line 203) will be replaced for \$2.2 million and \$2.1 million,
4 respectively. A leak in the shell of feedwater heater No. 6 was discovered
5 in March 2023. Phased Array Ultrasonic Testing (PAUT) identified an 8"
6 long crack in the shell. Further PAUT scanning found several smaller
7 connected indications on the inside diameter of the shell. Additional
8 borescope inspection revealed multiple internal weld cracks located between
9 the desuperheating zone and the drain cooling zone of the feedwater heater.
10 The feedwater heater needs to be replaced to restore reliable service. The
11 existing feedwater heater No. 3 is experiencing an increasing number of tube
12 leaks and requires replacement to restore reliability. Both feedwater heaters
13 take waste heat from the LP turbines and use it to preheat boiler feedwater
14 improving the overall efficiency of the steam power cycle. All steam turbine
15 power cycles utilize feedwater heating in this manner.
- 16 • The Greenwood Unit 1 turbine valves will be rebuilt for \$1.8 million
17 (Exhibit A-12, Schedule B5.1, page 7, line 204). The valves are worn and
18 require overhaul to operate safely and properly. These valves provide
19 overspeed protection for the turbine and prevent possible catastrophic
20 failure.
- 21 • The Greenwood Unit 1 north boiler feed pump turbine last row of blades will
22 be replaced for \$1.5 million to correct erosion damage on the existing blades
23 (Exhibit A-12, Schedule B5.1, page 7, line 205).
- 24 • \$1.3 million will be spent to replace Greenwood Energy Center underground
25 storage tank No. 377 (Exhibit A-12, Schedule B5.1, page 7, line 206). The

Line
No.

- 1 tank has been in service for over 30 years. Underground storage tanks that
2 have been in service for this many years have an increased risk of failure,
3 potentially allowing the contents to leak, contaminating the soil and
4 groundwater around the tank. Tank No. 377 contains gasoline fuel with a
5 capacity of 2,500 gallons.
- 6 • Monroe Unit 1 IP turbine rotor (Exhibit A-12, Schedule B5.1, page 7, line
7 207) replacement will be completed for \$4.2 million. During offsite
8 inspection in 2023, creep void indications of cracking were found in the bore
9 and the stage 1 wheel dovetail roots. The OEM performed the work required
10 to return the rotor to service on a short-term basis but also provided further
11 analysis of the rotor that confirmed the need to replace the rotor soon,
12 concluding that it could only be returned to service for no more than 30
13 months.
 - 14 • Monroe Unit 1 SCR catalyst modules for layer 3 will be replaced for \$2.5
15 million (Exhibit A-12, Schedule B5.1, page 7, line 208). The catalyst
16 module replacements are required to maintain compliance with air permit
17 emission limits for NOx and ammonia slip guidelines.
 - 18 • Monroe Unit 1 coal mill feeder controls will be replaced for \$1.4 million
19 (Exhibit A-12, Schedule B5.1, page 7, line 209). The current coal mill feeder
20 controls for all seven (7) coal mills are original equipment (1970's).
21 Reliability of this equipment has diminished, causing unit derates.
22 Replacing the obsolete controls is needed to address the reliability issues.
23 This controls project upgrade will improve reliability, accuracy of measuring
24 coal flow, and boiler efficiency.

Line
No.

- 1 • In preparation for the Monroe Unit 2 periodic outage in 2026, \$11.0 million
- 2 will be spent to continue procurement payments on material to forge new
- 3 LP turbine rotors and blades (Exhibit A-12, Schedule B5.1, page 7, line
- 4 210). Replacement is needed due to the industry-wide problem of stress
- 5 corrosion cracking on the current LP turbine forgings. In addition, Monroe
- 6 Unit 2 SCR catalyst modules for layers 1, 2, and 4 will be purchased for
- 7 \$4.4 million (Exhibit A-12, Schedule B5.1, page 7, line 211). The catalyst
- 8 module replacements are required to maintain compliance with air permit
- 9 emission limits for NO_x and ammonia slip guidelines. Finally, \$3.0 million
- 10 will be spent to purchase materials for replacing the Monroe Unit 2 north
- 11 and south air heater hot-end baskets (Exhibit A-12, Schedule B5.1, page 7,
- 12 line 212). The baskets have significant deterioration which limits heat
- 13 transfer capability and impacts operational performance. The integrity,
- 14 reliability, and efficiency of the Monroe Unit 2 north and south air heaters
- 15 will be restored.
- 16 • \$5.3 million will be spent to complete the replacement of the Monroe Unit 4
- 17 LPA and LPB turbine rotors and blades (Exhibit A-12, Schedule B5.1, page
- 18 7, line 213). Refurbishment is needed due to the industry-wide problem of
- 19 stress corrosion cracking on the current LP turbine which could result in
- 20 unexpected catastrophic failure. The LP rotors that were installed on
- 21 Monroe Unit 1 in 2001 have been replaced with new upgraded rotors in
- 22 2023. Due to the cost of forging new rotors or the extended outage required
- 23 to perform the refurbishment of the Monroe Unit 4 rotors, Unit 4's rotors
- 24 will be replaced with those that were removed from Unit 1. The Unit 1 rotors

Line
No.

- 1 will be inspected and refurbished to provide safe and reliable operation of
2 the Unit 4 LP turbines until the projected retirement of Unit 4 in 2028.
- 3 • \$4.2 million will be spent to overhaul the Monroe Unit 4 turbine valves
4 (Exhibit A-12, Schedule B5.1, page 7, line 214). Project scope includes the
5 four (4) stop valves, four (4) control valves, and 2 combined reheat stop
6 valves. The valves are worn and require overhaul for proper operation until
7 unit retirement. These valves provide overspeed protection for the turbine
8 and prevent possible catastrophic failure.
 - 9 • Monroe Unit 4 SCR catalyst modules for layers 1, 3, and 4 will be replaced
10 for \$3.6 million (Exhibit A-12, Schedule B5.1, page 7, line 215). The
11 catalyst module replacements are required to maintain compliance with air
12 permit emission limits for NO_x and ammonia slip guidelines.
 - 13 • \$2.6 million will be spent to complete the Monroe Unit 4 coal mill primary
14 air duct and dampers project (Exhibit A-12, Schedule B5.1, page 7, line 216).
15 The existing ductwork is thinning, resulting in fugitive dust leaks, and
16 requires replacement.
 - 17 • \$2.4 million will be spent to complete replacement of Monroe Unit 4
18 expansion joints (Exhibit A-12, Schedule B5.1, page 7, line 217). Fourteen
19 (14) high priority Monroe Power Plant Unit 4 expansion joints have been
20 identified to be replaced due to leakage. A leak can affect unit reliability,
21 efficiency, and result in a safety risk to plant personnel.
 - 22 • \$2.1 million will be spent to replace the Unit 4 FGD inlet expansion joint
23 and flanges on both upstream and downstream sides of the joint (Exhibit A-
24 12, Schedule B5.1, page 7, line 218). The inlet expansion joint is essential
25 to reliability for inlet flue gas to enter the absorber tower. It allows for

Line
No.

- 1 expansion and contraction of the inlet duct with changing temperatures
2 (during a shutdown/startup of the unit). The existing joint and flange surface
3 is damaged and needs replacement to allow the joint to seal.
- 4 • \$1.9 million will be spent to complete the Monroe Unit 4 DCS and control
5 room modifications (Exhibit A-12, Schedule B5.1, page 7, line 219). The
6 equipment and software are at risk from a reliability perspective, requiring
7 modifications to keep the plant's control systems reliable. The DCS
8 hardware was last replaced over a decade ago and the associated software
9 dates to the 1980's. Additionally, the equipment is no longer supported by
10 the vendor. The Company has scaled back this project to focus on the critical
11 work necessary to support continued operations to 2028.
 - 12 • The Monroe Unit 4 secondary heat exchanger (Exhibit A-12, Schedule B5.1,
13 page 7, line 220) will be replaced for \$1.9 million. The Unit 4 secondary
14 heat exchanger is an original piece of equipment (1970's era) and provides
15 process heat to the combustion coils that are needed for unit start-up and
16 building heating which will continue to be needed after unit retirement. The
17 existing secondary heat exchanger has become unreliable due to an
18 increasing number of tube leaks. Replacement of the secondary heat
19 exchanger will improve unit reliability and maintain building heating
20 requirements.
 - 21 • \$2.1 million will be spent to install new piping within the Monroe urea to
22 ammonia (U2A) systems (Exhibit A-12, Schedule B5.1, page 7, lines 221
23 and 222). The emergency cooling and condensate systems have started to
24 leak and show heavy corrosion after 15 years of service. The U2A system
25 is common to all four units and required to be operational at all times.

Line
No.

1 Shutdown of the U2A system results in forced outages to all four Monroe
2 Power Plant units. This project will install new cooling water supply and
3 condensate return lines supporting the four U2A reactors and restore reliable
4 operations to this critical environmental control equipment.

- 5 • Monroe fuel supply tripper car gallery D will have the floor replacement
6 (9,890 square feet of elevated structure) completed for \$7.1 million (Exhibit
7 A-12, Schedule B5.1, page 7, line 223). The original tripper gallery floor,
8 supporting floor beams, and floor beam top flanges have corroded over time
9 and require replacement to ensure worker safety during washdown activities
10 required to control fugitive and combustible coal dust. There are 9 galleries
11 (sections) in the tripper gallery that serve all four Monroe Power Plant units,
12 designated by letters A, B, C, D, E, F, G, H, and J. Floor beam inspections
13 were conducted to determine the condition of the gallery and prioritize
14 sections based on the results. The inspection included the gallery conveyor
15 floor system, floor plates, and floor supporting structural steel. Gallery D
16 was identified as the next priority area in the inspection. Support beams
17 and girders show signs of degradation and need to be replaced. This project
18 will restore the structural integrity of the floor, the floor beams, girders, and
19 associated connection hardware for this gallery section.
- 20 • \$1.9 million will be spent to replace the Fuel Supply Dust Collector No. 4
21 (Exhibit A-12, Schedule B5.1, page 7, line 224). The replacement will
22 mitigate combustible dust and comply with the NFPA combustible dust
23 guidelines.

Line
No.

1 **Routine Capital Expenditures - Hydraulic Power Generation**

2 **Q78. What were the Company's routine capital expenditures in 2022 for Hydraulic**
3 **Power generation (Ludington)?**

4 A78. During 2022, the Company's Energy Supply group's routine capital expenditures
5 for the Ludington Pumped Storage facility were \$13.0 million as shown on Exhibit
6 A-12, Schedule B5.1, page 3 of 9, line 8, column (b). Expenditures were related to
7 unit and HVAC maintenance, powerhouse roof replacement, lower penstock
8 expansion joint chamber water stop replacement, and controls upgrades and
9 replacements.

10

11 **Q79. What will be the Company's routine capital expenditures for Hydraulic Power**
12 **Generation (Ludington) in the 24 months ending December 31, 2024?**

13 A79. During the 24 months ending December 31, 2024, Energy Supply routine capital
14 expenditures for the Ludington Pumped Storage facility are projected to be \$19.3
15 million as shown on Exhibit A-12, Schedule B5.1, page 3 of 9, line 8, column (e).
16 Investments will be related to the replacements of the powerhouse roof, lower
17 penstock expansion joint chamber water stop, barrier net panels, oil water separator,
18 and control relays and performing unit maintenance and upgrades to auxiliary
19 equipment.

20

21 **Q80. What will be the Company's routine capital expenditures for Hydraulic Power**
22 **Generation (Ludington) in the projected test year, the 12 months ending**
23 **December 31, 2025?**

24 A80. During the 12 months ending December 31, 2025, the Company's routine capital
25 expenditures for the Ludington Pumped Storage facility are projected to be \$10.8

Line
No.

1 million as shown on Exhibit A-12, Schedule B5.1, page 3 of 9, line 8, column (f).
2 Investments will be related to replacements of control relays, governors, barrier net
3 panels, and oil water separator, as well as station power transformer and other unit
4 maintenance.

5

6 **Routine Capital Expenditures - Other Power Generation**

7 **Q81. What bulk electric system support is provided by the peaking units included**
8 **in Other Power Generation?**

9 A81. DTE Electric's fleet of peaking units are primarily valued for their capacity and
10 ability to start up quickly and reliably in response to high peak customer demand
11 and the variable circumstances on the Company's distribution system throughout
12 its 7,600 square mile service territory. The safe, reliable operation of these peaking
13 units is also an important factor in system balancing as additional intermittent
14 resources are integrated into the grid.

15

16 **Q82. What were the Company's routine capital expenditures greater than \$1**
17 **million in 2022 for Other Power Generation?**

18 A82. During 2022, the Company's routine capital expenditures for Other Power
19 Generation units was \$66.7 million as shown on Exhibit A-12, Schedule B5.1, page
20 3 of 9, lines 9-10, column (b). These expenditures include the following projects
21 that individually exceeded \$1 million as detailed on page 4 of Exhibit A-12,
22 Schedule B5.1:

- 23 • \$6.5 million was spent to complete the Belle River 12-1 major overhaul
24 (Exhibit A-12, Schedule B5.1, page 4, line 53). This work was required for
25 continued safe and reliable operation. Major maintenance intervals for gas

Line
No.

1 turbines are established by the cumulative run hours and startup sequences
2 experienced.

3 • In preparation for the Belle River 12-2 Peaker major overhaul outage in
4 2023, \$2.1 million was spent to continue procurement of materials (Exhibit
5 A-12, Schedule B5.1, page 4, line 54). This work was required for continued
6 safe and reliable operation. Major maintenance intervals for gas turbines are
7 established by the cumulative run hours and startup sequences experienced.

8 • \$2.0 million was spent to replace the generator field on Belle River 12-1
9 (Exhibit A-12, Schedule B5.1, page 4, line 55). This work was required for
10 continued safe and reliable operation. Generator field replacements for gas
11 turbines are established by the years of service and the frequency of start/stop
12 cycles experienced by the unit.

13 • In preparation for combustion overhauls in 2023, material procurement was
14 completed for Belle River 13-1 (Exhibit A-12, Schedule B5.1, page 4, line
15 56) and Greenwood 12-1 (Exhibit A-12, Schedule B5.1, page 4, line 57)
16 Peakers for \$1.7 million each. The projects included the replacement of fuel
17 nozzles, support housings, combustor baskets, transition pieces, as well as
18 inner and outer transition seals. This work was required to ensure continued
19 safe and reliable operation. Major maintenance intervals for gas turbines are
20 established by the cumulative run hours and startup sequences experienced.

21 • Combustion overhauls were completed on Greenwood 11-1 (Exhibit A-12,
22 Schedule B5.1, page 4, line 58) and Greenwood 11-2 (Exhibit A-12,
23 Schedule B5.1, page 4, line 59) Peakers for \$1.5 million and \$1.2 million,
24 respectively. These projects included the replacement of fuel nozzles,
25 support housings, combustor baskets, transition pieces, as well as inner and

Line
No.

- 1 outer transition seals. This work was required for continued safe and reliable
2 operation. Major maintenance intervals for gas turbines are established by
3 the cumulative run hours and startup sequences experienced.
- 4 • The Renaissance Unit 4 (Exhibit A-12, Schedule B5.1, page 4, line 60) and
5 Renaissance Unit 1 (Exhibit A-12, Schedule B5.1, page 4, line 62) Peakers
6 (163 MW each) completed major overhauls for \$13.5 million and \$7.4
7 million, respectively. These were the first major maintenance overhauls
8 since the units were installed in 2002. The overhauls were required to
9 maintain the peakers' availability and included corrective maintenance on
10 the compressor, combustion system, gas turbine blading, and hot gas path.
 - 11 • In preparation for the Renaissance Unit 3 Peaker (163 MW) major overhaul
12 in 2023, \$9.7 million was spent to procure materials for the overhaul (Exhibit
13 A-12, Schedule B5.1, page 4, line 61). This was the first major maintenance
14 since the unit was installed in 2002. The overhaul was required to maintain
15 peaker availability and includes corrective maintenance on the compressor,
16 combustion system, gas turbine blading, and hot gas path.
 - 17 • \$3.6 million was spent for engineering and material procurement of the
18 Renaissance Unit 3 Peaker exhaust cylinder and manifold replacement
19 (Exhibit A-12, Schedule B5.1, page 4, line 63). Recent exhaust system
20 inspections completed on Renaissance Unit 3 revealed degradation of
21 components and struts, material distress, and weld cracks. The integrity of
22 the exhaust turbine casing and cylinder were at risk of failure and required
23 replacement.
 - 24 • The exhaust silencers (baffles) on the Renaissance Unit 3 Peaker were
25 replaced for \$2.9 million (Exhibit A-12, Schedule B5.1, page 4, line 64).

Line
No.

1 The exhaust silencer baffles were degrading, and inspections identified
2 metal debris and insulation material loss. The new baffles improve sound
3 attenuation of the unit, supporting permit compliance.

4 • \$2.0 million was spent to start procurement of a Renaissance spare main unit
5 transformer (Exhibit A-12, Schedule B5.1, page 4, line 65). The previous
6 spare transformer will be installed on Renaissance Unit 1 in 2024. This
7 transformer is needed for fleet reliability in the event of a failure of one of
8 the other Renaissance main unit transformers.

9 • In preparation for replacing the exhaust silencers (baffles) on the
10 Renaissance Unit 4 Peaker in 2023, \$1.3 million of materials were procured
11 (Exhibit A-12, Schedule B5.1, page 4, line 66). The previous exhaust
12 silencer baffles were degraded, and inspections identified metal debris and
13 insulation material loss. The new baffles improve sound attenuation of the
14 unit, supporting permit compliance.

15

16 **Q83. What are the routine projects with projected capital expenditures greater than**
17 **\$1 million in 2023 for Other Power Generation?**

18 A83. Planned 2023 Other Power Generation maintenance projects greater than \$1 million
19 are detailed on page 5 of Exhibit A-12, Schedule B5.1 and described below. The
20 individual projects with greater than \$1 million expenditures in 2023 for Other
21 Power Generation units include:

22 • A Belle River 12-2 Peaker major overhaul outage was completed in 2023 for
23 \$5.4 million (Exhibit A-12, Schedule B5.1, page 5, line 114). Additionally,
24 the Greenwood 11-1 Peaker will prepare for a 2024 major overhaul outage
25 with engineering for \$1.4 million (Exhibit A-12, Schedule B5.1, page 5, line

Line
No.

- 1 117). This work is required for continued safe and reliable operation. Major
2 maintenance intervals for gas turbines are established by the cumulative run
3 hours and startup sequences experienced.
- 4 • During the annual borescope inspection, emergent work was found to be
5 required for the Belle River 13-1 Peaker Modified Hot Gas Path Overhaul
6 and is projected for \$1.4 million (Exhibit A-12, Schedule B5.1, page 5, line
7 115). Hardware damage as the result of a failed transition piece end seal,
8 which was found in good condition in the spring borescope inspection, was
9 identified within the combustion and turbine sections. The transition seal
10 will be repaired, damaged 1st stage buckets will be replaced, and minor
11 damage on the 2nd and 3rd stage hardware will be addressed.
 - 12 • The generator field was replaced on the Belle River 12-2 (Exhibit A-12,
13 Schedule B5.1, page 5, line 116) Peaker for \$1.4 million. This work was
14 required for continued safe and reliable operation. Generator field
15 replacements for gas turbines are established by the years of service and the
16 frequency of start/stop cycles experienced by the unit.
 - 17 • The generator field was replaced on the Northeast 13-2 Peaker for \$1.6
18 million (Exhibit A-12, Schedule B5.1, page 5, line 118). This work was
19 required to replace failed equipment and for continued safe and reliable
20 operation. The generator field failed in 2022 and required replacement.
 - 21 • The Renaissance Unit 4 Peaker (163 MW) generator stator was rewound and
22 the rotor was replaced (Exhibit A-12, Schedule B5.1, page 5, line 119) with
23 a projected \$9.2 million project expense. This rewind and rotor replacement
24 was required because Renaissance Unit 4 experienced a ground fault on the
25 generator. During the inspection phase of the project, the neutral side main

Line
No.

- 1 leads were found to have flashed between two phases, damaging insulation
- 2 material and stator components.
- 3 • The Renaissance Unit 3 Peaker (163 MW) completed a major overhaul in
- 4 2023 for \$7.1 million (Exhibit A-12, Schedule B5.1, page 5, line 120). This
- 5 was the first major maintenance since the unit was installed in 2002. The
- 6 overhaul was required to allow the return of the peaker to service and
- 7 included corrective maintenance on the compressor, combustion system, gas
- 8 turbine blading, and hot gas path.
- 9 • During the annual borescope inspection, emergent work was found to be
- 10 required for the Renaissance Unit 2 Peaker (163 MW) Modified Hot Gas
- 11 Path Overhaul and is projected for \$3.7 million (Exhibit A-12, Schedule
- 12 B5.1, page 5, line 121). Significant erosion with material loss was identified
- 13 at the row 1 turbine vane trailing edges and at the row 1 turbine blade leading
- 14 edges. Replacement of the row 1 vane and blade assemblies will be
- 15 completed to address these issues.
- 16 • The exhaust silencer baffles on the Renaissance Unit 2 (Exhibit A-12,
- 17 Schedule B5.1, page 5, line 122) and Renaissance Unit 4 (Exhibit A-12,
- 18 Schedule B5.1, page 5, line 124) Peakers were replaced for \$2.3 million and
- 19 \$1.7 million, respectively. The exhaust silencer baffles were degrading, and
- 20 inspections identified metal debris and insulation material loss. The new
- 21 baffles improved sound attenuation of the unit, supporting permit
- 22 compliance.
- 23 • \$1.8 million was spent to complete the Renaissance Unit 3 exhaust cylinder
- 24 and manifold replacement (Exhibit A-12, Schedule B5.1, page 5, line 123).
- 25 Exhaust system inspections completed on Renaissance Unit 3 revealed

Line
No.

1 degradation of components and struts, material distress, and weld cracks.
2 The inspections indicated the integrity of the exhaust turbine casing and
3 cylinder were close to failure and required replacement.
4 • Procurement of a Renaissance unit compatible spare main unit transformer
5 was completed for \$1.2 million (Exhibit A-12, Schedule B5.1, page 5, line
6 125). This transformer was needed for fleet reliability in the event of a
7 failure of any one of the Renaissance main unit transformers.

8

9 **Q84. What are the routine projects with projected capital expenditures greater than**
10 **\$1 million in 2024 for Other Power Generation?**

11 A84. Planned Other Power Generation maintenance projects greater than \$1 million in
12 2024 are detailed on page 6 of Exhibit A-12, Schedule B5.1 and described below.
13 The individual projects with greater than \$1 million expenditures in 2024 for Other
14 Power Generation units include:

15 • \$3.7 million will be spent to complete the Blue Water Energy Center
16 circulating water pumps enclosure project (Exhibit A-12, Schedule B5.1,
17 page 6, line 144). Although the plant is designed to operate at minus 24
18 degrees Fahrenheit, the weather experienced in December 2022 revealed that
19 certain wind direction and ice-forming conditions could still negatively
20 impact plant reliability. During these conditions, the motor air filters on the
21 circulating water pumps become plugged with ice which obstructs airflow
22 and causes the motors to overheat and shutdown. Additionally, the cooling
23 tower stairs, which are located immediately adjacent to the circulating water
24 pumps, also experience heavy icing. Enclosing the circulating water pump,
25 supporting systems, and the cooling tower stairs protects them from the

Line
No.

1 cooling tower plume during the winter and will prevent forced outages and
2 reduce the risk of employee injury.

3 • The Blue Water Energy Center conference room building (Exhibit A-12,
4 Schedule B5.1, page 6, line 145) will be completed for \$3.3 million. In the
5 December 1, 2023 Commission Order from the last rate case No. U-21297,
6 the Commission did not allow the inclusion of this project in rate base at that
7 time due to what it considered insufficient information. To provide the
8 further explanation and justification, the Company offers the following:

9
10 The current office space configuration provides the fulltime employees of
11 Blue Water with 25 available workspaces for their daily use. The 25
12 workspaces are at times not sufficient because the site workforce can surge
13 to 100-plus personnel in support of routine and major maintenance activities.

14
15 During construction of the plant, the large construction workforce used a
16 significant number of temporary trailers for this purpose. Other DTE
17 Electric power plant sites have repurposed original construction buildings
18 that were converted to functional plant conference rooms when construction
19 was completed.

20
21 This new building will also support craft labor onboarding requirements,
22 which include safety training and onsite orientation. Due to the open-air
23 design of the Blue Water Energy Center, there are insufficient enclosed
24 spaces available to support these onboarding requirements. Conversely,
25 other DTE Electric power plant sites have historically utilized large open

Line
No.

1 spaces that are inherent in the design of the plant boiler / turbine buildings
2 to temporarily accommodate the needs of craft labor. A drawing of the
3 conference building layout is provided in my workpapers in support of this
4 project.

5 • \$1.5 million will be spent for material procurement to replace the Blue Water
6 Energy Center plant control system server (Exhibit A-12, Schedule B5.1,
7 page 6, line 146). The current version of the Windows Operating System at
8 Blue Water Energy Center is based on Microsoft Windows Server 2012
9 validated by General Electric at the time the Blue Water project was
10 commenced. That version has a service end date of October 2023 and needs
11 to be upgraded to maintain software security and reliability protocols.

12 • \$1.1 million will be spent to start procurement of a spare Blue Water Energy
13 Center steam turbine generator transformer (Exhibit A-12, Schedule B5.1,
14 page 6, line 147). There is no transformer available that meets the electrical
15 configuration requirements for the Blue Water Energy Center steam turbine
16 generator. It is both reasonable and prudent to initiate the procurement of a
17 spare transformer at this time, especially considering the multi-year
18 manufacturing time requirement. A failed transformer could cause an
19 extended forced outage of 2-3 years.

20 • A combustion overhaul will be completed on the Belle River 13-1 Peaker
21 for \$1.4 million (Exhibit A-12, Schedule B5.1, page 6, line 178). The project
22 includes the replacement of fuel nozzles, support housings, combustor
23 baskets, transition pieces, as well as inner and outer transition seals. This
24 work is required for continued safe and reliable operation. Major

Line
No.

- 1 maintenance intervals for gas turbines are established by the cumulative run
- 2 hours and startup sequences experienced.
- 3 • A blackstart peaker unit starting system will be replaced for \$2.8 million
- 4 (Exhibit A-12, Schedule B5.1, page 6, line 179). The unit starting system is
- 5 obsolete and requires replacement with an up-to-date design. Components
- 6 of the existing unit starting system, installed in 1999, are no longer supported
- 7 by the OEM and other suppliers.
- 8 • Greenwood 11-1 Peaker major overhaul outage will be completed in 2024
- 9 for \$6.8 million (Exhibit A-12, Schedule B5.1, page 6, line 180). This work
- 10 is required for continued safe and reliable operation. Major maintenance
- 11 intervals for gas turbines are established by the cumulative run hours and
- 12 startup sequences experienced.
- 13 • The exhaust silencers (baffles) on the Greenwood 11-1, 11-2, and 12-1
- 14 Peakers will be replaced for \$2.9 million (Exhibit A-12, Schedule B5.1, page
- 15 6, line 181). The exhaust silencer baffles are degrading, and inspections
- 16 identified metal debris and insulation material loss. The new baffles will
- 17 improve sound attenuation of the unit, supporting permit compliance.
- 18 • The generator field will be replaced on the Greenwood 11-1 (Exhibit A-12,
- 19 Schedule B5.1, page 6, line 182) Peaker for \$1.7 million. This work is
- 20 required to ensure continued safe and reliable operation. Generator field
- 21 replacements for gas turbines are established by the years of service and the
- 22 frequency of start/stop cycles experienced by the unit.
- 23 • The Renaissance Unit 1 (Exhibit A-12, Schedule B5.1, page 6, line 183) and
- 24 Renaissance Unit 3 (Exhibit A-12, Schedule B5.1, page 6, line 184) Peakers
- 25 (163 MW each) generator stator rewind and rotor replacements will be

Line
No.

1 completed for \$7.4 million and \$7.0 million, respectively. Previous
2 inspections on Renaissance units revealed a high level of risk for in-service
3 faults that need to be addressed to prevent failure. Accordingly, these units
4 require a generator stator rewind and rotor replacement to avoid an in-service
5 failure.

- 6 • The main unit transformer on the Renaissance Unit 1 Peaker will be replaced
7 for \$1.7 million (Exhibit A-12, Schedule B5.1, page 6, line 185).
8 Transformer testing detected high internal gas levels, which is the leading
9 indicator of transformer failure requiring replacement. The spare
10 transformer utilized for this replacement was previously purchased and its
11 planned use triggered the Company to purchase a replacement spare as
12 discussed on page 116 of this testimony.

13

14 **Q85. What are the routine projects with projected capital expenditures greater than**
15 **\$1 million in 2025 for Other Power Generation?**

16 A85. Planned Other Power Generation maintenance projects greater than \$1 million in
17 2025 are detailed on page 7 of 9 in Exhibit A-12, Schedule B5.1 and described
18 below. The individual projects with greater than \$1 million of expenditures in 2025
19 for Other Power Generation units include:

- 20 • Material procurement for a Blue Water Energy Center steam turbine
21 generator transformer (Exhibit A-12, Schedule B5.1, page 7, line 198) and
22 Blue Water Energy Center combustion turbine transformer (Exhibit A-12,
23 Schedule B5.1, page 7, line 199) will continue for \$1.9 million and \$1.8
24 million, respectively. There are no transformers available for the Blue Water

Line
No.

- 1 Energy Center combustion turbines and steam turbine generator. A failed
2 transformer could cause an extended forced outage of 2-3 years.
- 3 • \$1.7 million will be spent to complete the Blue Water Energy Center plant
4 control system server upgrade (Exhibit A-12, Schedule B5.1, page 7, line
5 200). The current version of the Windows Operating System at Blue Water
6 Energy Center is based on Microsoft Windows Server 2012 validated by
7 General Electric at the time the Blue Water project was commenced. That
8 version has a service end date of October 2023 and needs to be upgraded to
9 maintain software security and reliability protocols.
 - 10 • A blackstart peaker starting system will be replaced for \$2.8 million (Exhibit
11 A-12, Schedule B5.1, page 7, line 225). The unit starting system is obsolete
12 and requires replacement with an up-to-date design. Components of the
13 existing unit starting system, installed in 1999, are no longer supported by
14 the OEM and/or other suppliers.
 - 15 • The exhaust silencers (baffles) on the Delray 11-1 and 12-1 Peakers will be
16 replaced for \$1.9 million (Exhibit A-12, Schedule B5.1, page 7, line 226).
17 The exhaust silencer baffles are degrading, and inspections identified metal
18 debris and insulation material loss. The new baffles will improve sound
19 attenuation of the unit, supporting permit compliance.
 - 20 • In preparation for major overhauls in 2026, engineering will begin for the
21 Greenwood 11-2 Peaker for \$1.2 million (Exhibit A-12, Schedule B5.1, page
22 7, line 227) and 12-1 Peaker for \$1.1 million (Exhibit A-12, Schedule B5.1,
23 page 7, line 228). This work is required for continued safe and reliable
24 operation. Major maintenance intervals for gas turbines are established by
25 the cumulative run hours and startup sequences experienced.

Line
No.

- 1 • \$8.7 million will be spent to complete the Renaissance Unit 4 Peaker (163
- 2 MW) exhaust cylinder and manifold replacement (Exhibit A-12, Schedule
- 3 B5.1, page 7, line 229). Exhaust system inspections completed on
- 4 Renaissance Unit 4 and sister units have revealed degradation of components
- 5 and struts, material distress, and weld cracks. The integrity of the exhaust
- 6 turbine casing and cylinder are at risk of failure and require replacement.
- 7 • The Renaissance Unit 2 Peaker (163 MW) generator rotor will be replaced
- 8 for \$3.2 million (Exhibit A-12, Schedule B5.1, page 7, line 230). This
- 9 generator work must be completed to correct the degradation of insulation
- 10 and copper and reduce the risk of extensive damage should a failure occur.
- 11 • A blackstart peaker major overhaul outage will begin for \$6.4 million
- 12 (Exhibit A-12, Schedule B5.1, page 7, line 231) and be completed in 2026.
- 13 This work is required for continued safe and reliable operation. Major
- 14 maintenance intervals for peakers are established by the cumulative run
- 15 hours and startup sequences experienced.

16

17 **AFUDC Estimate**

18 **Q86. Do the capital expenditures you are supporting include an allowance for funds**
19 **used during construction (AFUDC)?**

20 A86. Yes, capital expenditures include an AFUDC for eligible projects that are in
21 Construction Work in Progress (CWIP). At the direction of Company Witness
22 Uzenski, AFUDC is applied to projects greater than \$50,000 and lasting more than
23 six months, except for large environmental projects which are exempt from
24 AFUDC treatment.

25

Line
No.

1 **Q87. How much AFUDC is assumed in the projected test period for Energy Supply?**

2 A87. AFUDC for Energy Supply is included on Exhibit A-12, Schedule B5.1, page 8 of
3 9. As shown on line 16, column (c), the AFUDC is projected to be \$21.0 million
4 for the 12-month period ending December 31, 2025. A historical trend is used to
5 estimate AFUDC on routine capital since the mix of eligible projects is consistent
6 year-to-year, while the AFUDC is calculated specifically on a project-by-project
7 basis for eligible non-routine projects. The authorized cost of capital rate used is
8 5.561% consistent with the December 1, 2023 Case No. U-21297 Order. For
9 additional details on AFUDC refer to Company Witness Uzenski's direct
10 testimony.

11

12 **Removal Costs, Plant in Service and CWIP Forecast**

13 **Q88. What is provided on the schedule entitled Removal Costs, Plant in Service, and**
14 **CWIP schedule on page 9 of 9 of Exhibit A-12, Schedule B5.1?**

15 A88. This schedule provides a breakdown of plant activities which are used by Witness
16 Uzenski to forecast Plant in Service, Accumulated Depreciation, and CWIP on the
17 projected balance sheet. Capital expenditures consistent with Exhibit A-12,
18 Schedule B5.1, page 1 are summarized in columns (c) through (f). Column (b)
19 includes a corresponding in-service assumption: Annual is indicated for categories
20 of plant spend that are generally unitized within the year of spend, while a specific
21 in-service date is used for projects that remain in CWIP for more than a year before
22 moving into Plant in Service.

23

24 Column (g) includes an estimated percentage of removal costs that are included
25 within the capital expenditures. Removal costs, as discussed by Witness Uzenski,

Line
No.

1 are charged to Accumulated Depreciation rather than Plant/ CWIP and are therefore
2 not depreciable. Removal cost of 15% based on historical trend of removals as a
3 component of capital expenditures is applied to routine expenditures on lines 2
4 through 6. 100% is applied to specific removal and decommissioning projects on
5 lines 9, 10, and 22 and 0% is applied to non-removal projects on lines 11 and 12.
6 Finally, 0% is applied to new build projects on lines 15 through 21 since there is no
7 related removal work.

8
9 Column (h) through (j) reflect calculated removal costs based on projected Capital
10 Expenditures in columns (d) through (f) multiplied by the removal cost % in column
11 (g). The remaining Capital Expenditures will appear in Plant in Service columns
12 (k) through (m) if in-service assumption is "Annual", or CWIP columns (n) through
13 (p) until the date of in-service as indicated in column (b). At that time, cumulative
14 spend including the historical period is transferred to in-service (excluding the
15 removal cost estimate). Major projects with a long lead time also reflect spend
16 from earlier years that will be transferred out of CWIP into Plant in Service on the
17 in-service date.

18

19 **Part III – Energy Supply Operation and Maintenance Expenses**

20 **Q89. What is the process used to prepare the Energy Supply operating and**
21 **maintenance (O&M) projected level of expense?**

22 A89. Projected O&M expense is developed by taking historical test year O&M
23 expenditure data and adjusting for any known projected period changes. Plant level
24 changes include labor and material cost increases, cost variations related to

Line
No.

1 environmental equipment operation, non-periodic maintenance cost variations
2 driven by predictive maintenance programs, and other known changes.

3

4 The overall Energy Supply O&M projection for steam, hydraulic, and other
5 generation assets is developed by adjusting the actual historic test year (2022)
6 results for rate case adjustments between witnesses, normalization adjustments to
7 the 2022 data, and known and measurable adjustments to handle O&M changes (up
8 or down). O&M projections in this case do not include funding for Energy Supply
9 renewable generation wind and solar assets that are handled in other regulatory
10 filings.

11

12 Energy Supply operations expenses are those associated with day-to-day operation
13 of the Company's generating units, including certain Account 501 fuel handling
14 expenses. Energy Supply maintenance expenses are associated with periodic
15 outages, non-periodic outages, and other maintenance activities. Other
16 maintenance activities include standard day-to-day work to maintain plant
17 equipment, such as inspections, servicing, and minor maintenance that does not
18 require the unit to be taken offline to complete.

19

20 Energy Supply O&M is presented in three major cost categories as shown below:

- 21 • Steam Power Generation
- 22 • Hydraulic Power Generation
- 23 • Other Power Generation

24

Line
No.

1 **Q90. What were Energy Supply's historical O&M Expenditures for 2022 for Steam**
2 **Power Generation?**

3 A90. During 2022, Steam Power Generation adjusted O&M expenses totaled \$231.5
4 million as shown on Exhibit A-13 Schedule C5.1, line 19, column (g). This was
5 comprised of \$105.2 million in operations costs and \$126.3 million in maintenance
6 costs. The \$8.3 million of Steam Power Generation O&M that relates to Fuel
7 Supply and Midwest Energy Resources Company (MERC) Fuel Handling is
8 sponsored by Company Witness Milo on Exhibit A-13, Schedule C5.2 and is
9 subtracted on line 20 (Note 1), resulting in remaining Steam Power Generation
10 adjusted O&M in the amount of \$223.2 million.

11

12 **Q91. Can you provide an overview of Exhibit A-13, Schedule C5.1?**

13 A91. Exhibit A-13, Schedule C5.1 shows total projected test period O&M for Steam
14 Power Generation by starting with the 2022 actual O&M expenses and adjusting
15 for rate case eliminations, normalization/other adjustments, and inflation
16 adjustments. The historical adjustment is required to determine the portion of the
17 2022 O&M expenses that will reoccur in the 12-month period ending December
18 31, 2025. The normalization adjustment credit of \$0.099 million is shown in note
19 4. There are also "Other" credit adjustments of \$31.5 million required in column
20 (k) and shown in note 6 to project the O&M required in the 12-month forecasted
21 test period ending December 31, 2025.

22

23 **Q92. What major O&M expense categories are found in Exhibit A-13, Schedule**
24 **C5.1?**

Line
No.

1 A92. The expenses shown in Exhibit A-13, Schedule C5.1 are categorized into the major
2 categories of operations and maintenance consistent with FERC accounting
3 guidelines.

4
5 Operations account 500 includes the cost of plant management for the individual
6 plant sites, their supporting staffs, and the Energy Supply Engineering Support
7 Organization. Plant management includes plant site director, area managers, and
8 administrative support. The major supporting staffs in this area are the technical
9 and engineering personnel associated with problem solving daily plant operating
10 issues, obtaining and interpreting test data, and developing long-term operating and
11 maintenance plans to maintain plant availability and efficiency.

12
13 Operations account 501 "Fuel Handling" includes expenses incurred for coal train
14 and vessel unloading, ash disposal, coal pile management, and mobile equipment
15 operations. Depending on plant site and delivery options, plants maintain and
16 manage a coal pile inventory that can vary over many months. Larger coal pile
17 inventories are required at the Belle River Power Plant at the end of December to
18 ensure adequate coal supplies when vessel deliveries cannot be obtained due to
19 winter ice on the Great Lakes.

20
21 Accounts 502 and 505 represent operations personnel and materials expenses
22 associated with direct operating supervision and control of boiler, turbine,
23 generator, water, and environmental control systems. Shift supervisor and control
24 room supervising operators are key to the successful steam power generation unit
25 operations that are required to ensure adequate and cost-efficient production of

Line
No.

1 electrical energy for our customers. Their labor expenses are captured in these
2 accounts.

3
4 Account 506 "Misc. Steam Power Expenses" includes Instrument and Controls
5 personnel to troubleshoot and calibrate the vast array of complex instruments and
6 controls found on steam generating units. Also included in this account are
7 operations of all common equipment such as water, air, and cooling equipment
8 systems. Plant buildings and grounds cleaning, landscaping, snow removal, and
9 maintenance are also captured in this account.

10

11 Maintenance accounts 510 through 514 capture expenses associated with planned
12 and unplanned maintenance activities. These expenses mostly consist of the
13 planned maintenance activities that generally occur on a two to five-year interval
14 on all boiler systems and on a six to ten-year interval on turbine systems. Account
15 510 captures management of the plant maintenance area including area managers
16 and general foremen. Account 511 covers maintenance of common infrastructure
17 areas such as roofs, windows, and roads. The major area of expense captured in
18 account 512 "Maintenance of Boilers" includes maintenance expenses for internal
19 and external labor and all materials associated with planned and unplanned outage
20 work on the boilers. The boiler maintenance scope of work includes the boilers, air
21 and flue gas systems, ash handling, and fuel burning equipment. The major area of
22 expense captured in account 513 "Maintenance of Electric Plant" includes internal
23 and external labor and materials expenses associated with work on turbines. The
24 major area of expense captured in account 514 "Maintenance of Misc. Steam Plant"

Line
No.

1 includes internal and external labor and materials expenses for maintenance of all
2 common equipment such as water, air, and cooling equipment systems.

3

4 **Q93. Can you provide additional detail on the O&M expenses incurred for the**
5 **Company's Steam Power Generation during 2022?**

6 A93. Yes. In the historic period of 2022, the Company spent \$223.2 million in Steam
7 Power Generation O&M expenses after adjustments and reclassifications. Planned
8 major periodic maintenance outages were executed in 2022 on Belle River Unit 1
9 and Monroe Unit 2. Also completed during 2022 were multiple short duration unit
10 tune-up outages on various units to allow their continued efficient operation
11 burning high percentages of lower sulfur coals. Costs for the portions of outages
12 that occur in years other than 2022 will be captured in those years.

13

14 The other category of maintenance expenses incurred during the historic period
15 were associated with regular plant maintenance while units were in operation or
16 expenses to repair or replace equipment during a forced or unplanned unit outage.
17 These short duration unplanned maintenance outages can generally be completed
18 in three to seven days and will be experienced at varying intervals on all steam
19 power generating units depending on the severity of the service cycles and the time
20 elapsed since the last planned maintenance outage.

21

22 During the projected 12-month period ending December 31, 2025, the Company
23 will execute major periodic maintenance outages on Belle River Unit 1, Greenwood
24 Unit 1, and Monroe Unit 4, and minor periodic maintenance on Monroe Unit 1. As

Line
No.

1 in the historic period, short duration unit tune-up outages will also be completed on
2 various steam power generation units to optimize continuing performance.

3

4 **Q94. What adjustments were made to the historical test period amounts?**

5 A94. Fuel Handling O&M expenses recorded in Fuel Account 501 are added to Steam
6 Power O&M in column (d). This amount includes Fuel Supply and MERC Fuel
7 Handling for which an adjustment is made in column (e) to reclassify non-O&M
8 fuel handling sponsored by Witness Milo (Note 3). In column (f) detailed in Note
9 4, there is one (1) historical adjustment:

- 10 • A credit for \$99 thousand for the removal of EEI membership dues as
11 supported by Witness Uzenski.

12

13 **Q95. Can you describe some of the benefits the Company and its customers realize**
14 **through its memberships in industry associations, such as the Electric Power**
15 **Research Institute (EPRI)?**

16 A95. Yes. As discussed by Witness ~~FoleyCrozier~~, memberships in industry associations
17 provide the Company access to benchmarking/best practices, research, and
18 networking opportunities.

19

20 Specifically, with respect to EPRI, the Company collaborates with other utilities to
21 fund technical projects that study and resolve critical industry issues. For instance,
22 EPRI guidelines for boiler water chemistry and steam purity are commonly
23 referenced to protect plant equipment and maintain reliable operations. In addition
24 to the knowledge benefits gained through involvement in EPRI studies, the

Line
No.

1 membership is cost-effective. The costs for the Company to perform even one of
2 these projects would be greater than the cost of the membership.

3

4 **Q96. What are the inflation factors shown in Note 5 of Exhibit A-13 Schedule C5.1?**

5 A96. Note 5 contains the inflation factors that are utilized to forecast the changes
6 necessary to transition needed O&M funding from the historic test year of 2022 to
7 the projected test year ending December 31, 2025. The labor and material inflation
8 adjustment factor of 3.20% for 2023, 2.90% for 2024, and 2.90% for 2025 is
9 supported by Witness Uzenski.

10

11 **Q97. Can you provide a further explanation of the \$31.5 million projected test year
12 credit adjustment (reduction) shown on note 6 of Exhibit A-13, Schedule C5.1?**

13 A97. Yes. The \$31.5 million projected test year credit (reduction) adjustment shown in
14 this exhibit reflects projected test year modifications needed to transition from 2022
15 actual O&M expenses to those required in the 12 months ending December 31,
16 2025. The labor and material inflation adjustment factor of 3.20% for 2023, 2.90%
17 for 2024, and 2.90% for 2025 is supported by Witness Uzenski:

18 • The first adjustment is a credit of \$18.3 million and represents the St. Clair
19 Power Plant's operation and maintenance expenses in 2022 that will not
20 occur in the projected test period, as St. Clair Power Plant retired in 2022.
21 A portion of St. Clair Power Plant's 2022 expenses are not included in the
22 adjustment. The portion not included is \$2.7 million of fuel supply costs
23 common to St. Clair and Belle River Power Plants that were transferred to
24 Belle River Power Plant because they are necessary for providing fuel to
25 Belle River in the projected test year. The Belle River and St. Clair Power

Line
No.

1 Plants share a common coal vessel unloading facility that continues to be
2 required to support the Belle River Power Plant after the St. Clair Power
3 Plant retired.

- 4 • The second adjustment is a credit of \$13.1 million and represents the Trenton
5 Channel Power Plant's operation and maintenance expenses in 2022 that will
6 not occur in the projected test period, as the Trenton Channel Power Plant
7 retired in 2022. A portion of Trenton Channel Power Plant's 2022 expenses
8 are not included in the adjustment. The portion not included is \$0.4 million,
9 representing Sibley Quarry's operation and maintenance costs. Sibley
10 Quarry will continue operation beyond the date of the Trenton Channel
11 Power Plant's retirement because it provides waste disposal services to
12 Monroe Power Plant and other DTE business units.

13

14 **Q98. Can you summarize Exhibit A-13, Schedule C5.4, entitled "Operations and**
15 **Maintenance Expenses - Hydraulic Power Generation"?**

16 A98. Exhibit A-13, Schedule C5.4 represents DTE Electric's share of the continuing
17 operation and maintenance expense of the Ludington Pumped Storage facility. As
18 a 49 percent owner of this facility, the Company incurs expenses for operating and
19 maintaining the facility. The forecasts for these expenses through the projected test
20 period are based on the historic labor and materials expenses adjusted for inflation.
21 The labor and material inflation adjustment factor of 3.20% for 2023, 2.90% for
22 2024, and 2.90% for 2025 is supported by Witness Uzenski. No other historical or
23 projected adjustments were made to Hydraulic Power Generation Projected
24 Operation and Maintenance expenses.

25

Line
No.

1 **Q99. Can you summarize Exhibit A-13, Schedule C5.5, entitled “Operations and**
2 **Maintenance Expenses - Other Power Generation?**

3 A99. Exhibit A-13, Schedule C5.5 represents DTE Electric’s peaker fleet O&M costs, as
4 well as Blue Water Energy Center, which began commercial operations in June
5 2022. DTE Electric owns and operates a quantity of peaking units ranging from
6 2.5 MW diesel-fueled engines to newer 163 MW natural gas-fired combustion
7 turbines. The main driver of projections for these expenses through the projected
8 test period is the labor and material required to support these peaker assets and Blue
9 Water Energy Center. Included in this category will also be the labor expenses for
10 the Generation Optimization and Integrated Resource Planning teams. The
11 forecasts for these expenses through the projected test period are based on the
12 historic labor and materials expenses as adjusted for inflation. The labor and
13 material inflation adjustment factor of 3.20% for 2023, 2.90% for 2024, and 2.90%
14 for 2025 is supported by Witness Uzenski.

15

16 **Q100. Did you make any adjustments to the historical test period operations and**
17 **maintenance expenses for other power generation?**

18 A100. Yes. I eliminated \$37.7 million of total 2022 test year O&M, listed in column (d)
19 of Exhibit A-13, Schedule C5.5 because these expenses are related to the renewable
20 energy program which are not associated with the instant case.

21

22 **Q101. What adjustments were made to the projected test period amounts for other**
23 **power generation?**

24 A101. In column (i) detailed in Note 3 of Exhibit A-13, Schedule C5.5, there is an upward
25 adjustment for \$6.3 million in support of Blue Water Energy Center’s operation.

Line
No.

1 Of the \$6.3 million total adjustment, \$4.67 million is in support of ongoing base
2 operation and maintenance, while \$1.67 million is in support of the estimated
3 levelized major periodic O&M expense not covered by the contract service
4 agreement with the OEM. The plant began commercial operations in June of 2022.

5

6 Also, \$0.31 million is forecasted in 2025 to support of the first full year of Slocum
7 BESS operations.

8

9 Finally, there is a decrease of \$0.2 million related to the retirement and suspension
10 of operations of peaker units (River Rouge 11, Slocum 11, and St. Clair 12
11 retirements and Fermi 11-3 and Fermi 11-4 suspension of operations).

12

13 **Q102. What are your thoughts concerning the level of DTE Electric's historical and**
14 **projected capital and O&M expenses contained in your testimony?**

15 A102. DTE Electric has been reasonable and prudent in past capital and O&M
16 expenditures, and I anticipate this to continue through the projected test period and
17 beyond. During this same timeframe, generation unit availability is managed
18 through a rigorous process that continues to be focused on prudent capital and
19 O&M expenditures. I believe that DTE Electric has fully justified as reasonable
20 and prudent its request for recovery of the Energy Supply plant expenses that are
21 set forth in my testimony and associated exhibits.

22

23 **Q103. Does this complete your direct testimony?**

24 A103. Yes, it does.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of)
DTE ELECTRIC COMPANY)
for authority to increase its rates, amend)
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

THERESA M. UZENSKI

DTE ELECTRIC COMPANY
QUALIFICATIONS AND REVISED DIRECT TESTIMONY OF THERESA M.
UZENSKI

Line
No.

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

2 A1. My name is Theresa M. Uzenski (she/her/hers). I am employed by DTE Energy
3 Corporate Services, LLC, a subsidiary of DTE Energy Company (DTE Energy).
4 My business address is One Energy Plaza, Detroit, MI 48226.

5

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

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

8

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

10 A3. I have a Bachelor of Science in Accounting from the University of Detroit and a
11 Master of Business Administration with a concentration in Finance from Wayne
12 State University.

13

14 **Q4. What is your work experience and what position do you currently hold at DTE**
15 **Energy?**

16 A4. I have worked for DTE Energy or one of its affiliated regulated utilities for over
17 thirty-four years in various accounting, finance, and management positions. I am
18 currently the Manager of Regulatory Accounting for DTE Electric Company as
19 well as DTE Gas Company.

20

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

Line
No.

1 A5. I am a Certified Management Accountant, a member of the Institute of Management
2 Accountants, and a member of the Corporate Accounting Committee of the Edison
3 Electric Institute and American Gas Association.

4
5 **Q6. What are your current duties and responsibilities?**

6 A6. As Manager of Regulatory Accounting, I am responsible for the development and
7 management of regulatory accounting policies and practices and supporting
8 regulatory filings. My department analyzes the accounting implications of new
9 legislation and Michigan Public Service Commission (Commission or MPSC)
10 orders and provides expert testimony on accounting issues and financial projections
11 in various proceedings before the MPSC. We research and establish accounting
12 policies and assist the accounting operations departments with implementation. My
13 department also supports other Company expert witnesses in various proceedings
14 before the MPSC by preparing financial exhibits and other financial analyses.

15
16 **Q7. Have you previously sponsored testimony before the Michigan Public Service**
17 **Commission (MPSC or Commission)?**

18 A7. I have sponsored testimony in the following cases:
19 U-11222 Michigan Consolidated Gas Company (MichCon) Depreciation
20 U-13898 MichCon UETM
21 U-14702 Detroit Edison 2006 PSCR Plan
22 U-15160 Detroit Edison Enhanced Security Cost Recovery
23 U-15244 Detroit Edison Choice Incentive Mechanism Reconciliation
24 U-15259 Detroit Edison Pension Equalization Mechanism
25 U-15417-R Detroit Edison Pension Equalization Mechanism

Line
No.

1	U-15806-EO	Detroit Edison Energy Optimization
2	U-15768	Detroit Edison UETM
3	U-15890	MichCon Energy Optimization
4	U-16009	Complaint Case against Detroit Edison
5	U-16246-R	Detroit Edison 2009 RETM Reconciliation
6	U-16246-R	Detroit Edison 2010 RETM Reconciliation
7	U-16356	Detroit Edison 2009 REP Reconciliation
8	U-16472	Detroit Edison 2010 Rate Case
9	U-16574	Detroit Edison 2010 UETM Reconciliation
10	U-16582	Detroit Edison 2014 REP Plan
11	U-16769	MichCon Depreciation
12	U-16952	Detroit Edison 2014 CIM Reconciliation
13	U-16956	Detroit Edison 2014 RETM Reconciliation
14	U-16964	Detroit Edison 2014 UETM Reconciliation
15	U-17302	DTE Electric Company 2017 REP Plan Update
16	U-17437	DTE Electric Company Transitional Cost Recovery Mechanism
17	U-17767	DTE Electric Company 2014 Rate Case
18	U-17999	DTE Gas Company 2015 Rate Case
19	U-18014	DTE Electric Company 2018 Rate Case
20	U-18122	DTE Electric Company Customer 360 Program Accounting
21	U-18255	DTE Electric Company 2017 Rate Case
22	U-18419	DTE Electric Company Certificates of Necessity
23	U-18999	DTE Gas Company 2018 Rate Case
24	U-20106	DTE Gas Company Tax Cut & Jobs Act – Credit A
25	U-20105	DTE Electric Company Tax Cut & Jobs Act – Credit A

Line
No.

1	U-20162	DTE Electric Company 2018 Rate Case
2	U-20298	DTE Gas Company Tax Cut & Jobs Act – Credit C
3	U-20561	DTE Electric Company 2019 Rate Case
4	U-20642	DTE Gas Company 2019 Rate Case
5	U-20940	DTE Gas Company 2021 Rate Case
6	U-21015	DTE Electric Company 2021 Securitization
7	U-20836	DTE Electric Company 2022 Rate Case
8	U-21193	DTE Electric Company 2022 Integrated Resource Plan
9	U-21297	DTE Electric Company 2023 Rate Case
10	U-21291	DTE Gas Company 2024 Rate Case

Line
No.

1 **Purpose of Testimony**

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

3 A8. The purpose of my testimony is to support DTE Electric's financial statements for
4 the historical test year ended December 31, 2022, the interim forecast period and a
5 twelve-month projected test period ending December 31, 2025, with certain
6 adjustments necessary for presenting the financial information in the appropriate
7 format for ratemaking purposes. My testimony supports the development of the
8 projected test year adjusted Electric operating income based on forecasted changes
9 from the normalized historical Electric operating income. I will discuss how costs
10 recovered from other mechanisms are excluded from the financial statements in this
11 case including Renewable Energy Program (REP) and Energy Waste Reduction
12 (EWR). I will support the Corporate Staff Group (CSG) capital and Operations and
13 Maintenance (O&M) expenses for the historical and forecasted periods and explain
14 the function of this group including the method for allocating costs to DTE Electric
15 and other DTE subsidiaries through the Shared Asset charge.

16

17 I also explain the accounting treatment of the Monroe regulatory asset and
18 amortization over 15 years. Witness Vangilder supports the revenue requirement.
19 In addition, I request regulatory asset and liability accounts for the Company's
20 proposed storm cost sharing mechanism supported by Witness Foley.

21

22 **Q9. What exhibits are you sponsoring in this proceeding?**

23 A9. I am supporting the following exhibits for the historical period:

Line
No.

<u>1</u>	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
2	A-2	B2	Historical Utility Plant
3	A-2	B3	Historical Depreciation Reserve
4	A-2	B4	Historical Working Capital
5	A-2	B5	Historical 13-Month Average Adjusted Balance
6			Sheet with Classifications
7	A-2	B5.1	Historical Year-End Adjusted Balance Sheet with
8			Classifications
9	A-2	B6	Historical Adjusted Balance Sheet – Year Ended and
10			13-Month Average
11	A-2	B6.1	Historical Year-End Adjusted Balance Sheet
12	A-2	B6.2	Historical 13-Month Average Adjusted Balance
13			Sheet
14	A-2	B7	ARO & Nuclear Decommissioning Trust Fund
15	A-3	C1	Historical Adjusted Net Operating Income
16	A-3	C1.1	Adjustments to Historical Net Operating Income
17	A-3	C3	Historical Operating Revenue
18	A-3	C4	Historical Fuel and Purchased Power
19	A-3	C5	Historical Operation and Maintenance Expenses
20	A-3	C6	Historical Depreciation and Amortization Expenses
21	A-3	C11	Historical Allowance for Funds Used During
22			Construction
23	A-3	C14	Historical Corporate Membership Adjustment
24	A-3	C15	Historical Advertising Adjustment
25	A-3	C16	Historical MERC Net Operating Income

Line
No.

1	A-3	C17	Historical Power Supply Cost Recovery Items
2	A-3	C18	Eliminate Nuclear Surcharge
3	A-3	C19	Historical Executive Incentive Compensation
4			Adjustment
5	A-3	C20	Historical Employee Incentive Plan Normalization
6			Adjustment
7	A-3	C21	Historical Weather Normalization Adjustment
8			

9 I am also supporting the following exhibits for the projected test year:

10	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
11	A-12	B2	Projected Utility Plant
12	A-12	B3	Projected Depreciation Reserve
13	A-12	B4	Projected Working Capital
14	A-12	B4.1	Projected Average Balance Sheet with Classification
15	A-12	B4.2	Projected Balance Sheet
16	A-12	B4.3	Common Equity Reconciliation
17	A-12	B4.4	Monroe Regulatory Asset - Projected Balance
18	A-12	B4.5	Monroe Regulatory Asset - Calculation
19	A-12	B5	Projected Capital Expenditures – Summary
20	A-12	B5.8	Projected Capital Expenditures – Corporate Staff
21	A-13	C1	Projected Net Operating Income
22	A-13	C1.1	Projected Net Operating Income Adjustments
23	A-13	C3	Projected Operating Revenue
24	A-13	C5	Projected O&M Expense – Summary
25	A-13	C5.6.2	ADMS Regulatory Asset Amortization

Line
No.

1	A-13	C5.9.1	Charging Forward Regulatory Asset Amortization
2	A-13	C5.9.3	ACPP and TOD Regulatory Asset Amortization
3	A-13	C5.10	Projected Administrative and General Expenses
4	A-13	C5.10.1	Incentive Deferral Mechanism
5	A-13	C5.15	Inflation Factors
6	A-13	C5.17	PERC (Nuclear Projects) Regulatory Asset
7			Amortization
8	A-13	C6	Projected Depreciation and Amortization Expense
9	A-13	C11	Projected Allowance for Funds Used During
10			Construction
11	A-13	C11.1	AFUDC Ratemaking Adjustment
12	A-13	C12	Projected Amortization of the Loss on Reacquired
13			Debt
14	A-13	C13	Projected Other (Income) / Deductions

15

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

17 A10. Yes, they were.

18

19 **Q11. How were your exhibits prepared?**

20 A11. My team, under my direction, uses an Excel model to create historical and projected
21 balance sheets and income statements, and the supporting exhibits. We also have
22 models to capture historical and projected O&M and capital expenditures. The
23 O&M and capital models feed into the financial statement model. Our models start
24 with historical financial information from the MPSC Annual Report on Form P-
25 521. I calculate most of the rate case normalizations and adjustments to the

Line
No.

1 historical balance sheet and income statement, but other Company witnesses
2 calculate the adjustments to the O&M and capital expenditures for the business unit
3 costs that they support. In addition, Company Witnesses Vangilder and
4 Wisniewski support certain adjustments to interest and taxes. I support the O&M
5 and capital costs for the Corporate Staff Group other than Information Technology
6 (IT).

7
8 After the normalizations and adjustments are made to the historical period, I use
9 the adjusted amounts to develop the financial statements for the projected period.
10 Again, the witnesses supporting their business unit costs provide the known and
11 measurable adjustments to O&M expense and the details for the capital
12 expenditures. Sales revenue and fuel and purchased power are calculated by
13 Company Witness Willis. Income and property taxes are calculated by Witness
14 Wisniewski. The data provided by these witnesses is captured in my models to
15 create the consolidated financial statements for the projected period. My projected
16 financial statement data is then used by Witness Vangilder to calculate the revenue
17 deficiency.

18

19 **Q12. Can you explain the history of the Transitional Recovery Mechanism (TRM)?**

20 A12. Yes. The City of Detroit operated a 139 square mile public lighting department
21 (PLD) serving approximately 115 retail electric customers and a street lighting
22 system and decided to exit the electric distribution business. On July 11, 2013, the
23 Commission issued an order in Case No. U-17427, authorizing DTE Electric to
24 defer for accounting purposes, the net incremental revenue requirement associated
25 with the disposition of the PLD electric distribution business and transfer of PLD

Line
No.

1 customers to DTE Electric retail service. On May 13, 2014, the Commission issued
2 an order in Case No. U-17437 approving a TRM and tariffs to recover the net
3 deferred costs. The deferred net incremental revenue requirement has been
4 reviewed in annual reconciliation cases starting with Case No. U-17761 covering
5 the period ending December 31, 2014. The transition of the PLD electric retail
6 service to DTE Electric was completed in 2022. Therefore, the deferral of the net
7 revenue requirement for the former PLD customers (that were converted to DTE
8 Electric's system) has ceased, and the revenues and costs are instead included in
9 base rates effective with the Order issued in Case No. U-20836 on November 18,
10 2022. A final TRM reconciliation was filed on October 31, 2022, in Case No. U-
11 21307 covering the period January 1, 2021 through October 31, 2022. On July 26,
12 2023 the Commission issued an Order approving the final reconciliation and
13 ratemaking for the TRM.

14

15 **Q13. How does the end of the PLD cost deferral and the TRM impact the exhibits**
16 **and the revenue requirement in the instant case?**

17 A13. Consistent with prior rate cases, I have removed the TRM surcharge revenue and
18 the related regulatory asset because they are addressed in the TRM reconciliation
19 process. The final under recovery of the TRM is addressed in the final
20 reconciliation case filed on October 31, 2022.

21

22 **Q14. Would you summarize the treatment of the TRM in this case?**

23 A14. Consistent with Case No. U-21297, the rate base supporting the former PLD
24 customers and the cost of service on that rate base are reflected in the historical and
25 projected financial exhibits. It is necessary to include the rate base supporting the

Line
No.

1 former PLD customers in this case because these costs are no longer recovered
2 through the TRM surcharge effective November 1, 2022. Please refer to Exhibit
3 A-2, Schedule B6.1, column (k). The only item being eliminated from the balance
4 sheet is the TRM regulatory asset on line 43 representing costs incurred before
5 November 2022. It is being recovered via a separate surcharge through February
6 2024.

7

8 **Q15. What is the impact to the historical and projected income statements?**

9 A15. The exhibits include the sales revenue from PLD customers along with the related
10 base fuel and purchased power expense. Please see Workpaper TMU-6. The TRM
11 elimination in the instant case reflects only the surcharge revenue and O&M costs
12 that will not recur.

13

14 **Historical Test Year**

15 **Q16. What information are you providing regarding the Historical Test Year ended**
16 **December 2022?**

17 A16. For the historical test year ended December 2022, I am providing the balance sheet
18 and net operating income (NOI) information with certain adjustments that are
19 necessary to present the financial information in the appropriate ratemaking format.
20 The adjusted historical financial statements are the starting point in creating the
21 financial statements for the projected test period.

22

23 **Historical Balance Sheet**

24 **Q17. What historical test year balance sheet information are you providing?**

Line
No.

1 A17. Exhibit A-2, Schedules B2 and B3 provide the historical utility plant and
2 depreciation reserves, respectively. Schedule B4 provides the historical 13-month
3 average for working capital. Schedule B5 classifies the historical balance sheet
4 information into the categories of net plant, working capital, and the various
5 financing components adjusted to use a 13-month average. Schedule B5.1 provides
6 the same classifications based on a historical year-end balance.
7
8 Exhibit A-2, Schedule B6 shows the historical balance sheet amounts on a historical
9 year-end and 13-month average incorporating the adjustments detailed on
10 schedules B6.1 and B6.2. Schedule B6.1 contains the historical test year balance
11 sheet information on December 31, 2022. Schedule B6.2 is a 13-month average
12 balance sheet for the periods December 2021 through December 2022. The
13 columns for both schedules detail the same types of adjustments.
14
15 Schedules B6.1 and B6.2, column (b) values are from the MPSC Annual Report on
16 Form P-521. Column (c) adds the balance sheet values for the Midwest Energy
17 Resources Company (MERC), a wholly owned subsidiary of DTE Electric
18 involved in low-sulfur western coal storage and transshipment operations. MERC
19 has been incorporated in the preparation of all exhibits. Pursuant to the
20 Commission's Order in Case No. U-5108, capital costs incurred by MERC,
21 including depreciation and property taxes, administrative expenses, income tax,
22 interest, and return on rate base are to be considered in the Company's main electric
23 ratemaking process. Column (d) is the consolidated balance on which I base my
24 adjustments.
25

Line
No.

1 **Q18. What adjustments are you making to the consolidated historical period**
2 **financial statements?**

3 A18. Consistent with the treatment in past cases, I am reclassifying certain items,
4 removing non-utility items, and removing balances that are being recovered or
5 refunded via other mechanisms or surcharges including EWR, REP, and PSCR.
6 For each regulatory asset and liability amount excluded, I removed the related
7 Accumulated Deferred Federal Income Tax (ADFIT) with the remaining capital
8 removed from short-term debt, as these items are considered temporary working
9 capital requirements. I am removing the Combined Operating License (COL) for
10 ratemaking purposes. Additionally, I am removing the Tree Trim Regulatory Asset
11 and Tier 2 plant assets that have been securitized.

12

13 The adjustments are shown on the balance sheets on Exhibit A-2, Schedules B6.1
14 and B6.2, columns (e) through (p). Since I used the adjusted historical period to
15 build the forecast, I did not have to make these same adjustments to the projected
16 period. I discuss each adjustment below.

17

18 **Q19. What is the adjustment for taxes?**

19 A19. Column (e) nets the Accumulated Deferred Income Tax Asset on line 67 and the
20 Investment Tax Credit (ITC) on line 114, with the Accumulated Deferred Income
21 Tax Liability on line 113. The ITC amount reflected in the reclassification is
22 supported by Witness Wisniewski.

23

24 **Q20. What is the adjustment for Tier 2 Plants?**

Line
No.

1 A20. The St. Clair and Trenton Channel “Tier 2” coal plants were retired in 2022 before
2 the end of their respective lives. In the June 22, 2023 Order in Case No. U-21338,
3 the Commission approved the securitization of \$594.1 million of St. Clair and
4 Trenton Channel net plant. The Commission also granted approval to classify these
5 costs as a regulatory asset. Therefore, in column (f), I reduced the Tier 2 Plants
6 regulatory asset by \$594.1 million, which were the combined balances of St. Clair
7 and Trenton Channel approved for securitization. The related capitalization of 50%
8 debt and 50% equity is also removed. This approach is consistent with the
9 Commission’s Order in the 2023 Securitization Case No. U-21338, which required
10 the balances related to the St. Clair and Trenton Channel generation sites to be
11 removed on a gross basis, with no impact to accumulated deferred income taxes.

12

13 **Q21. What is the elimination for Tree Trim?**

14 A21. The Commission authorized the Company’s Tree Trim surge program, allowing for
15 regulatory asset treatment of costs above an approved base amount in O&M. The
16 regulatory asset is not included in rate base because the balance through June 2021
17 of \$156.9 million was securitized pursuant to the Commission’s June 23, 2021
18 Order in Case No. U-21015. Additionally, the Company is planning a future
19 securitization of the Tree Trim regulatory asset once the balance is large enough as
20 described by Witness Lepczyk. Therefore, I removed the historical regulatory asset
21 and related capitalization of 50% debt and 50% equity in column (g). The revenue
22 requirement for the forecasted Tree Trim Surge regulatory asset, which represents
23 the tree trim costs not yet securitized, is separately calculated and supported by
24 Witness Vangilder on his Exhibit A-11, Schedule A1.1.

25

Line
No.

1 **Q22. What is the adjustment for the COL?**

2 A22. Per the Commission's Orders in Case Nos. U-18014 and U-17767, the COL asset
3 is being amortized over twenty years, but the balance remaining must be excluded
4 from rate base. Therefore, in column (h) I have removed both the COL asset
5 reflected on the books of DTE Electric and the related capitalization of debt and
6 equity at 50% each.

7

8 **Q23. What are the adjustments for programs and recovery mechanisms in columns**
9 **(i) through (k)?**

10 A23. Column (i) eliminates DTE Electric's EWR program. Column (j) eliminates the
11 REP, except for the regulatory liability, and column (k) eliminates the TRM related
12 to the conversion of the City of Detroit's PLD customers to DTE Electric. The
13 associated debt and equity eliminations are consistent with the capital structures
14 authorized by the Commission for each program.

15

16 **Q24. If the REP is excluded from base rates, then why are you not eliminating the**
17 **associated regulatory liability?**

18 A24. The regulatory liability generated from the REP program is not eliminated because
19 it is being used as a source of financing for DTE Electric's general rate base.
20 Therefore, I have reclassified the balance out of the regulatory liability on line 106
21 and reflected it as short-term debt on line 94.

22

23 **Q25. Why are you showing the REP regulatory liability as a source of financing for**
24 **general rate base instead of REP rate base?**

Line
No.

1 A25. Consistent with the Commission's Order in Case No. U-15806 the return embedded
2 in the REP surcharge reflects DTE Electric's approved cost of capital, primarily
3 long-term debt, and equity. However, because the REP revenue requirement was
4 collected in a surcharge separate from base rates, the remaining liability generated
5 from the previous surcharge is available to reduce DTE Electric's other short-term
6 debt, as approved by the Commission in Case No. U-15806.

7

8 **Q26. If DTE Electric is using the regulatory liability as a source of financing, then**
9 **how are DTE Electric's customers compensated?**

10 A26. The REP revenue requirement and surcharge is reduced by interest accrued on the
11 regulatory liability.

12

13 **Q27. What accounting adjustments are reflected in the Company's financial**
14 **presentation for the historical test year in this case?**

15 A27. This rate case reflects adjustments for Accounting Standards Codification (ASC)
16 842, Accounting for Right-of-Use Assets (Operating Leases); ASC 410,
17 Accounting for Asset Retirement Obligations; and ASC 715, Employers'
18 Accounting for Defined Benefit Pension and Other Postretirement Plans, because
19 the accounting impacts are excluded from the revenue requirement.

20

21 **Q28. What is the adjustment for leases?**

22 A28. The Financial Accounting Standards Board issued ASC 842, which requires
23 operating leases to be recognized on the balance sheet effective for DTE Electric in
24 2019. GAAP financial statements now include operating lease right-of-use assets
25 and liabilities. The Uniform System of Accounts does not include balance sheet

Line
No.

1 accounts for operating leases. The FERC ruled that the new lease accounting
2 standard cannot impact ratemaking, and operating lease expense must continue to
3 be based on actual amounts paid and be recorded as rent expense. I eliminated the
4 operating lease asset and related liabilities (short-term and long-term) in column (l)
5 to ensure there is no impact to ratemaking resulting from this new accounting
6 standard. Additionally, in column (l) I eliminated a deferred gain on the sale of
7 land associated with a prepaid lease for a parking structure that is amortized below
8 the line. In prior cases, the Commission ordered that this item was to be excluded
9 from rate base.

10

11 **Q29. What is the adjustment for asset retirement obligations?**

12 A29. The accounting for asset retirement obligations (ARO) results in timing differences
13 in the recognition of legal asset retirement costs for accounting purposes compared
14 to the recognition of amounts the Company is currently recovering in rates. ARO
15 accounting requires an up-front accrual for future legal removal costs as a liability.
16 Utility accounting recognizes the removal obligation in accumulated depreciation
17 and accrues it through depreciation expense over the life of the asset. The timing
18 differences are deferred under ASC 980, Regulated Operations. The ARO liability
19 is offset by a corresponding net plant Asset Retirement Cost and a regulatory asset,
20 which results in no impact on the revenue requirements in this case. A regulatory
21 asset does not offset the incremental liability related to the non-utility Fermi 1 site.

22

23 To ensure that there is no impact on revenue requirements from ARO accounting
24 in the forecast years, I have removed all 2022 regulated balance sheet impacts on
25 Exhibit A-2, Schedules B6.1 and B6.2, column (m). I also removed the ARO for

Line
No.

1 Fermi 1 and the related decommissioning trust fund asset. In addition, I have
2 removed the decommissioning obligation and related trust fund assets for Fermi 2.
3 The details of the balance sheet eliminations are shown on Exhibit A-2, Schedule
4 B7.

5
6 **Q30. What are the ARO and Nuclear Decommissioning Trust Fund eliminations**
7 **shown on Exhibit A-2, Schedule B7?**

8 A30. Exhibit A-2, Schedule B7 shows the components of ARO accounting as well as
9 nuclear decommissioning that are included in the unadjusted historical balance
10 sheet. The removal of the ARO items is consistent with DTE Electric's
11 presentation that the Commission has reviewed and accepted in all the Company's
12 rate cases beginning with Case No. U-15244.

13

14 **Q31. Why did you eliminate the Fermi 2 Nuclear Decommissioning Trust Fund?**

15 A31. The assets and related liabilities for Fermi 2 decommissioning net to zero with no
16 impact to rate base. For transparency, I removed all the line items from the
17 historical balance sheet consistent with the Company's presentation that was
18 reviewed and accepted by the Commission in its rate cases beginning with Case
19 No. U-18014.

20

21 **Q32. Can you explain the adjustment for benefit plans?**

22 A32. ASC 715 requires the recognition of the unfunded liabilities for defined benefit
23 pension and other postretirement plans with a charge to other comprehensive
24 income within equity. DTE Electric recorded a regulatory asset in place of the
25 charge to other comprehensive income because the costs are included in rates

Line
No.

1 consistent with when the expense is recognized in the income statement. Since the
2 liability and offsetting regulatory asset result in no change to revenue requirements,
3 Exhibit A-2, Schedules B6.1 and B6.2, column (n) eliminates the 2022 balance
4 sheet impacts related to ASC 715. This treatment is also consistent with DTE
5 Electric's presentation in all its rate cases starting with Case No. U-15244.

6

7 **Q33. What are the working capital normalizations in column (o)?**

8 A33. Customer Accounts Receivable is adjusted to remove the impact of weather.
9 Accounts Receivable from Associated Companies is adjusted to remove non-utility
10 balances. These adjustments decrease working capital by \$2.5 million on Schedule
11 B6.1 (year-end) and by \$1.2 million on Schedule B6.2 (13-month average).

12

13 **Q34. Why are you eliminating the items in column (p), Other?**

14 A34. Column (p) eliminates an asset for PSCR (\$420.8 million) that is reconciled in the
15 PSCR mechanism, and provisions for rate refunds including the \$30 million 2020
16 COVID regulatory liability that reversed during 2022 per the Commission's Order
17 in Case No. U-20921 and the \$90 million 2021 COVID regulatory liability that
18 reversed in 2022 and 2023 per the Commission's Order in Case No. U-21128. It
19 eliminates a software maintenance prepaid asset and the offsetting liability that net
20 to zero in working capital. It reclassifies a current lease payable out of short-term
21 debt to deferred credits. It eliminates a tax reserve that is recognized only for
22 GAAP purposes and eliminates affiliate Notes Receivable/Notes Payable that are
23 assumed settled in the projected period. It also removes non-utility amounts from
24 DTE Electric's consolidated balance sheets including the Detroit Investment Fund.
25 In prior cases, the Commission ordered that these items are to be excluded from

Line
No.

1 rate base. Column (p) also reflects the write-off of certain plant balances resulting
2 from the Order in Case No. U-21297, totaling \$26.2 million for which the Company
3 is no longer seeking recovery (primarily related to Information Technology
4 investments).

5

6 **Q35. What information is contained in column (q), on Exhibit A-2, Schedule B6.1?**

7 A35. Column (q), "Total Electric" represents the DTE Electric balance sheet as of
8 December 31, 2022, after adjustments. This Total Electric December 2022 balance
9 sheet is used by Witness Vangilder in determining DTE Electric's year-end
10 historical rate base and capitalization.

11

12 **Q36. What information is contained in column (q), Total Electric, on Exhibit A-2,**
13 **Schedule B6.2?**

14 A36. Column (q), Total Electric, represents the DTE Electric balance sheet after the
15 adjustments previously discussed. These 2022 Total Electric 13-month average
16 balances are used by Witness Vangilder in determining DTE Electric's average
17 historical rate base and capitalization.

18

19 **Q37. What information is shown on Exhibit A-2, Schedule B6?**

20 A37. Exhibit A-2, Schedule B6, page 1 is the Assets and Other Debits portion, and page
21 2 is the Liabilities and Other Credits portion of the DTE Electric Adjusted Balance
22 Sheet for December 2022. Column (b) reflects December 31, 2022 balances while
23 column (c) represents the 13-month average balances. Both columns are carried
24 from column (q) of Exhibit A-2, Schedules B6.1 and Schedule B6.2, respectively.

25

Line
No.

1 **Historical Income Statement**

2 **Q38. What information are you supporting on Exhibit A-3, Schedules C1 and C1.1,**
3 **Adjustments to Historical Net Operating Income (NOI)?**

4 A38. On Exhibit A-3, Schedules C1 and C1.1, DTE Electric's Adjusted Net Operating
5 Income (NOI) for the year ended December 31, 2022 was determined by starting
6 with the financial information reported on the Company's MPSC Annual Report
7 Form P-521, page 114. Then I adjusted the reported financial information for
8 certain exclusions and inclusions to get to a rate case filing level. The rate case
9 filing level was further adjusted by normalizations to remove unusual or one-time
10 events. I support the adjustments to NOI on Exhibit A-3, Schedule C1.1, except
11 for line 27 supported by Company Witness Guillaumin; line 28 supported by
12 Company Witness Kryscynski; line 33 supported by Company Witnesses Fix and
13 Hooper ~~Cooper~~; and lines 40 and 41, which are supported by Witness Vangilder.

14

15 **Q39. What information is displayed in Exhibit A-3, Schedule C3, Historical**
16 **Operating Revenue?**

17 A39. Exhibit A-3, Schedule C3 provides the amounts as reported on MPSC Annual
18 Report Form P-521 for retail, wholesale, refund provisions and miscellaneous
19 revenues, underlying the total revenue for the 12-month period ended December
20 31, 2022 and is carried forward to line 1, column (c), of Exhibit A-3, Schedule
21 C1.1.

22

23 **Q40. What is the purpose of Exhibit A-3, Schedule C4, Historical Fuel and**
24 **Purchased Power?**

Line
No.

1 A40. Exhibit A-3, Schedule C4 provides the amounts as reported on the MPSC Annual
2 Report Form P-521 for various accounts associated with power supply expenses for
3 the 12-month period ended December 31, 2022 and is carried forward to Exhibit
4 A-3, Schedule C1.1, column (d), line 1.

5
6 **Q41. What information is displayed in Exhibit A-3, Schedule C5, Historical**
7 **Operation and Maintenance Expense?**

8 A41. Exhibit A-3, Schedule C5 provides the amounts as reported on the MPSC Annual
9 Report Form P-521 for operation and maintenance expenses adjusted to exclude
10 fuel and purchased power expense for the 12-month period ended December 31,
11 2022 and is carried forward to Exhibit A-3, Schedule C1.1, column (e), line 1.

12
13 **Q42. What information is displayed in Exhibit A-3, Schedule C6, Historical**
14 **Depreciation and Amortization Expenses?**

15 A42. Exhibit A-3, Schedule C6 provides the amounts as reported on the MPSC Annual
16 Report Form P-521 for various accounts related to depreciation and amortization
17 expense for the 12-month period ended December 31, 2022, and is carried forward
18 to Exhibit A-3, Schedule C1.1, column (f), line 1.

19
20 **Q43. What information is contained on line 1 of Exhibit A-3, Schedule C1.1?**

21 A43. Net Operating Income of \$1,310.2 million is on line 1, column (m) and ties to the
22 MPSC Annual Report Form P-521, page 114, line 26.

23
24 **Q44. Why do you adjust Net Operating Income on Exhibit A-3, Schedule C1.1, lines**
25 **3 through 19?**

Line
No.

1 A44. These adjustments reflect certain inclusions and exclusions to the reported Net
2 Operating Income amount to arrive at an allowable rate case filing level. The
3 inclusions for AFUDC, interest and dividend income, MERC operating income,
4 customer interest, and amortization of loss on reacquired debt are allowable for
5 ratemaking, but they fall below the calculation of NOI on the Income Statement.
6 Conversely, the exclusions for certain corporate memberships and advertising,
7 executive incentives, and regulatory assets and liabilities recovered under separate
8 surcharges are not included for ratemaking, but they fall within the calculation of
9 NOI on the Income Statement.

10

11 **Q45. What adjustment to Net Operating Income did you make on line 3 on Exhibit**
12 **A-3, Schedule C1.1?**

13 A45. Line 3 reclassifies fuel handling from Fuel and Purchased Power to O&M.

14

15 **Q46. What are the adjustments on lines 5 through 19?**

16 A46. Exhibit A-3, Schedule C14, supports line 5, Excluded Corporate Memberships.
17 This schedule calculates the removal of social and service organization membership
18 expense for the year ended December 2022. All membership dues for Chambers
19 of Commerce are excluded from customer rates. The portion of other membership
20 dues related to political activities is also removed. Some organizations disclose the
21 portion of dues paid related to political activities on the invoice. For those amounts
22 recorded to an account excluded for ratemaking, no adjustment was necessary. If
23 the entire invoice was recorded to operating expense, I removed the portion related
24 to political activity, as disclosed on the invoice. The total adjustment decreases
25 O&M expense by \$0.4 million and increases NOI by \$0.3 million.

Line
No.

1 Line 6, Excluded Advertising Expenses, is supported by Schedule C15, which
2 classifies year ended December 2022 electric advertising expenses by categories as
3 prescribed by the standard filing requirements. Advertising expenses included for
4 ratemaking include public safety, conservation, and billing practices. This exhibit
5 identifies the advertising expenses that have historically been accepted by the
6 Commission and removes the remaining advertising expense. This adjustment
7 results in a decrease in O&M expense of \$5.7 million and an increase in NOI of
8 \$4.2 million.

9
10 Line 7, MERC NOI Adjustment, is supported on Schedule C16. MERC's net
11 income is effectively included in DTE Electric's NOI on Schedule C1.1, line 1.
12 This occurs in two ways. First, MERC charges DTE Electric for fuel handling and
13 that charge is included in DTE Electric's fuel expense (account 501) on Schedule
14 C1.1, line 1, column (d), which is then part of the fuel handling reclassification to
15 O&M expense on line 3, column (e). Second, MERC's profit or loss is included in
16 the PSCR. Third Party Revenues (consisting of Third-Party Dock Services plus
17 Net Coal & Transportation Sales) are credited, and Net Site Operating Expenses
18 are expensed to customers in the PSCR mechanism (through a change in the
19 delivered cost of coal). This inventory change is embedded in Fuel and Purchased
20 Power expense shown on Exhibit A-3, Schedule C1.1, line 1, column (d). These
21 two items are shown on Schedule C16, page 1 of 2. The fuel handling charge of
22 \$9.4 million together with the PSCR inventory change of \$7.1 million results in a
23 net contribution to consolidated DTE Electric for ratemaking of \$16.5 million as
24 shown on Schedule C16, column (b).

25

Line
No.

1 I will now explain details of the adjustment on Schedule C1.1, line 7. First, a
2 portion of the fuel handling charge recorded as O&M by DTE Electric is for
3 MERC's depreciation, taxes, and interest. As detailed on Schedule C16, page 2 of
4 2, column (c), I subtracted out the \$9.7 million fuel handling expense recorded by
5 DTE Electric and replaced it with the same amount but in the detailed
6 classifications shown in column (d). The total impact of the reclassification is
7 shown on Schedule C16, page 2 of 2, column (e) and is carried forward to Schedule
8 C1.1, line 7. The impact of this reclassification increases NOI by \$0.5 million,
9 representing MERC's interest expense. This net addition to NOI is necessary to
10 offset the expense reflected in DTE Electric's consolidated interest expense, which
11 includes debt for MERC. This ensures there is no impact to customers in base rates.

12

13 The Commission first authorized the above-described MERC accounting treatment
14 in MPSC Case No. U-5041 (Accounting and Ratemaking for MERC), Order dated
15 September 17, 1976, and reaffirmed its findings in MPSC Case No. U-5108
16 (General Electric Rate Case) Order dated May 27, 1977, as well as in MPSC Case
17 No. U-8578 (Detroit Edison's 1987 PSCR Plan Case), Order dated December 8,
18 1987.

19

20 Line 8, PSCR Offsets, is supported by Schedule C17, and details three adjustments
21 between revenue and fuel and purchased power. The first adjustment eliminates
22 the amount of revenues that are collected via the PSCR factor to reset historical
23 revenue to the PSCR base level. The second adjustment is to eliminate
24 interconnection and ancillary transmission revenues that are netted against PSCR
25 costs. Since these amounts are credited to customers in the PSCR reconciliation,

Line
No.

1 they need to be eliminated from revenues in net operating income for base rates.
2 The last adjustment is for steam revenue, which is included in net operating income,
3 but the related fuel cost is not recovered in the PSCR. To make up for this shortfall,
4 I reduced the revenue amount by the un-recovered cost. The sum of these three
5 adjustments is a \$547.3 million reclassification between revenue and fuel on
6 Exhibit A-3, Schedule C1.1, line 8.

7

8 Line 9 eliminates the revenues and expenses included in the nuclear surcharge.
9 Schedule C18 details the components supporting the \$0.6 million net operating
10 income adjustment.

11

12 Consistent with past practice, line 10 reduces incentive plan expense by \$10.2
13 million to remove the incentive compensation for DTE Electric's top five executive
14 officers. The adjustment is shown on Schedule C19.

15

16 Line 11, MGM Rent, supported by Workpaper TMU-4, is for an expense included
17 in O&M related to DTE Energy's use of a parking deck. I removed this expense to
18 match the treatment of a related gain on the sale of land underlying the parking deck
19 that is classified below the line. This adjustment results in a decrease in O&M
20 expense of \$1.0 million and an increase in NOI of \$0.7 million.

21

22 Line 12, Customer Deposit Interest, is supported by Workpaper TMU-5 and
23 reduces NOI by \$1.7 million recorded below the line as other interest in account
24 431. It is included as an operating expense in the Company's revenue requirement
25 since Customer Deposits are not included in the Company's capital structure.

Line
No.

1 Line 13 eliminates the revenues and expenses from the TRM related to former City
2 of Detroit PLD customers because it is recovered via a separate surcharge and is
3 not a part of base rates. Workpaper TMU-6 details the components supporting the
4 net income adjustment.

5

6 Line 14 eliminates the revenues and expenses from the EWR program because it is
7 recovered via a separate surcharge outside of base rates. Workpaper TMU-7 details
8 the components supporting the \$28.1 million NOI adjustment.

9

10 Line 15 eliminates the revenues and expenses from the REP because they are
11 included in the regulatory liability that is separate from the Company's base rates.
12 Workpaper TMU-8 details the components supporting the \$155.4 million NOI
13 adjustment.

14

15 Line 16 eliminates revenues and expenses related to the Low-Income Energy
16 Assistance Fund (LIEAF). This is a separate surcharge program, which has no
17 income impact. This adjustment as shown on Workpaper TMU-9 is necessary so
18 that the normalized NOI detail is comparable to the forecast period.

19

20 Line 17 eliminates miscellaneous event sponsorship expenses that are reclassified
21 to Other Deductions.

22

23 Line 18, Regional Relations Political Advocacy, removes \$314,000 of expense
24 related to lobbying and political advocacy activities that was incurred in the
25 historical test year, increasing NOI by \$233,000. (Note that the expense related to

Line
No.

1 federal and state activities was recorded to an account excluded from net operating
2 income. Thus, an elimination of those costs is not required.)

3

4 Line 19 Energy Insurance Services (EIS) relates to the Company's investment for
5 funding insurance. The Order in Case No. U-21297 requires the Company to
6 include a forecast of the income from the insurance fund in projected operating
7 income based on a five-year average in lieu of removing the EIS asset from working
8 capital. The adjustment on line 19 includes the five-year average of an EIS loss in
9 NOI.

10

11 **Q47. Why are you making normalization adjustments to NOI as reflected on**
12 **Exhibit A-3, Schedule C1.1, lines 23 through 41?**

13 A47. Consistent with current Commission policy, DTE Electric developed a projected
14 test year ending December 31, 2025, based on projected changes from the year
15 ended December 31, 2022 historical or actual test year. The year ended December
16 31, 2022 historic test year was adjusted to reflect the same normal baseline as the
17 twelve-months ending December 31, 2025 projected test year as far as rate levels,
18 weather impacts and one-time revenue or expense impacts. All adjustments were
19 made to the year ended December 31, 2022 reported NOI amount to arrive at a rate
20 case filing level as the starting point to develop the twelve-months ending
21 December 31, 2025 projected test year.

22

23 **Q48. What is the employee incentive plan normalization adjustment on line 23 of**
24 **Exhibit A-3, Schedule C1.1?**

Line
No.

1 A48. Line 23, Employee Incentive Plan Adjustment, is supported by Schedule C20 and
2 reduces 2022 incentives expense by \$4.8 million. The Company applies the equity
3 method to account for long-term Performance Shares; thus, any change in DTE
4 Energy's share price between the grant date and payout date is generally reflected
5 in DTE Energy's equity with no impact to expense. Long-term incentives in 2022
6 includes a \$4.1 million accrual for an increase in expense for the 2019 through 2022
7 performance shares based on performance relative to 100% of the target. Since an
8 incentives payout higher than the target may not recur, I have reduced that amount
9 from the historical expense. In addition, the short-term incentive plan design
10 (discussed in more detail by Witness ~~Fix~~ Cooper) allows for a payout within a range
11 of zero to 200% of the target, depending on actual results achieved. Short-term
12 incentive expense in 2022 includes \$1.4 million for amounts paid above the 100%
13 target, offset by \$0.6 million of prior period adjustments. Since payments above
14 the target and prior period adjustments may not recur, I have removed those
15 amounts.

16
17 **Q49. What is the basis for the \$24.3 million NOI Weather Normalization**
18 **Adjustment you are supporting on Exhibit A-3, Schedule C1.1, line 24?**

19 A49. The instant rate case assumes that for electric sales, historical normal weather will
20 occur for the forecast period. Thus, for comparison purposes the historical test year
21 must be adjusted to a normal weather basis. Weather was warmer than normal in
22 2022, increasing DTE Electric's pretax margin by \$32.8 million, and NOI by \$24.3
23 million, as shown on Schedule C21. Underlying the \$32.8 million pretax margin
24 increase was sales revenue of \$42.5 million offset in part by an increase in power

Line
No.

1 supply cost of \$9.7 million. Company Witness Leuker discusses the weather
2 impacts in more detail.

3

4 **Q50. What are the adjustments to O&M expense on lines 25 through 34?**

5 A50. Witness Kryscynski supports the adjustment on line 28 and I support the adjustment
6 on line 30 for expense items not expected to recur in the projected period. Lines
7 31 and 32 normalize expenses using averages due to the volatility in cost levels. I
8 support line 31, injuries and damages and line 32, environmental remediation, as
9 shown on my Exhibit A-13, Schedule C5.10; and Witness ~~es Fix and Hooper~~ ~~Cooper~~
10 supports line 33, benefits normalizations. I support line 34, Incentive Compensation
11 deferral above base amount, which increases O&M expense by \$856,000 and
12 decreases NOI by \$634,000. This normalization adjustment represents 2022
13 incentive compensation expense above the approved based amount established by
14 the Commission's Order in Case No. U-20836.

15

16 **Q51. What is the adjustment for the COVID-19 Voluntary Refund on line 35?**

17 A51. In Case No. U-20921, DTE Electric was authorized to accrue a one-time \$30
18 million regulatory liability in 2020 related to unusual sales patterns related to the
19 COVID pandemic. Amortization of the entire \$30 million regulatory liability took
20 place in 2022 and was used to offset the cost of service related to new DTE Electric
21 company plant.

22

23 **Q52. What are the adjustments on lines 38 through 41?**

24 A52. Line 38 adds \$37.5 million of AFUDC income to offset the impacts of including
25 construction work in progress (CWIP) in rate base. The federal, state, and local

Line
No.

1 income tax expense related to AFUDC and interest income is already included in
2 the income tax expense displayed on line 1, columns (i) and (j) of Exhibit A-3,
3 Schedule C1.1.

4
5 Line 39 represents Amortization of the Loss on Reacquired Debt. To reduce interest
6 costs, DTE Electric has redeemed and refinanced long-term debt securities in prior
7 years in advance of their scheduled maturities. The cost related to each of these
8 early redemptions is amortized over the life of the new issue as prescribed by the
9 Commission's Uniform System of Accounts. The year ended December 2022
10 amortization of the Loss on Reacquired Debt results in a decrease in net operating
11 income of \$3.3 million. This expense is displayed on a pretax basis since the tax
12 expense is already included in net operating income.

13
14 Line 40, Income Tax Effect of Interest, and line 41, Interest Synchronization, are
15 supported and explained by Witness Vangilder on Exhibit A-3, Schedules C12 and
16 C13, respectively.

17

18 **Q53. What is the Adjusted Normalized Year ended December 2022 NOI amount?**

19 A53. Inclusion of the rate case adjustments and normalization adjustments supported by
20 Company Witnesses Hatsios, Fix, Hooper, Cooper, Vangilder, Guillaumin,
21 Kryscynski, Wisniewski, and I result in an Adjusted Normalized year ended
22 December 2022 NOI of \$1,132.0 million. This amount is detailed on Exhibit A-3,
23 Schedule C1.1, line 43 and is included in the historical revenue deficiency/
24 (sufficiency) calculation supported by Witness Vangilder.

25

Line
No.

1 **Forecast Period**

2 **Q54. How was the financial forecast for the projected period, twelve months ending**
3 **December 31, 2025, prepared?**

4 A54. Projected DTE Electric financial statements for the twelve months ending
5 December 31, 2025 were based on projected changes from the adjusted normalized
6 amounts for the year ended December 31, 2022. The projected period reflects an
7 increase in revenue and higher net operating expenses. Revenue includes an
8 increase in electric sales revenue and increased inter-company rent revenue. The
9 revenue increases are offset by increased O&M, depreciation expense, income tax
10 expense and property taxes. As previously discussed, regulatory assets recovered
11 with surcharges are excluded from the forecast, so they will not impact base rate
12 determination. I prepared the forecasted financial statements using inputs from
13 numerous DTE Electric witnesses.

14

15 **Electric Income Statement Forecast**

16 **Q55. What information is included in the forecasted electric income statement**
17 **contained within this filing?**

18 A55. The income statement shown on Exhibit A-13, Schedule C1, column (e), represents
19 the projected DTE Electric NOI for the twelve-months ending December 31, 2025.
20 DTE Electric's financial statements represent DTE Electric Company plus MERC.
21 Exhibit A-13, Schedule C1.1 develops the twelve months ending December 31,
22 2025 DTE Electric operating income statement based on projected changes from
23 the year ended December 31, 2022 normalized amount.

24

Line
No.

1 **Q56. How did you develop the revenues reflected in DTE Electric's operating**
2 **income?**

3 A56. Line 1 of Exhibit A-13, Schedule C1, contains DTE Electric's revenues for the
4 forecasted twelve-months ending December 31, 2025. Generally, these revenues
5 were derived from the projected electric sales volumes provided by Witness Leuker
6 multiplied by existing tariff rates, as calculated by Company Witnesses Willis and
7 Bellini. These tariff rates include electric base tariff rates authorized in Case No.
8 U-21297. Total revenues also include certain utility related Miscellaneous
9 Revenues that I support. As shown on Exhibit A-13, Schedule C3, page 2, I have
10 excluded Nuclear, Securitization, EWR, REP, IRM, and LIEAF surcharge revenues
11 because they do not affect the revenue deficiency in base rates.

12

13 **Q57. What is the projected change in revenues from the historical normalized**
14 **period to the projected period?**

15 A57. Exhibit A-13, Schedule C1, column (d) shows that the projected change in revenues
16 is an increase of \$288.4 million. Schedule C3, page 1, of this exhibit compares the
17 2022 normalized revenue amount to the twelve-months ending December 31, 2025
18 revenue amount.

19

20 **Q58. Can you explain the revenue items on Exhibit A-13, Schedule C3?**

21 A58. Line 1 of Exhibit A-13, Schedule C3, page 1, represents electric sales distribution
22 revenue. These projected revenues include a full year of the increase in tariff rates
23 authorized in Case No. U-21297 effective in December 2023 and reflect lower
24 overall service area sales in the projected period. Sales are discussed by Witness
25 Leuker. Line 2 is the revenue that recovers base fuel and purchased power. The

Line
No.

1 change in this revenue component is the same amount as the change in base fuel
2 and purchased power expense, discussed in more detail below. Company
3 Witnesses Willis and Bellini support the twelve-months ending December 31, 2025
4 tariff revenue in their testimonies and exhibits.

5
6 Line 5 is Other Operating Revenues primarily consisting of: late payment charges,
7 miscellaneous service charges, real estate rentals, and inter-company shared asset
8 charges. The increase in the inter-company shared asset charge is due primarily to
9 additional information technology assets that support both Electric and Gas
10 operations. Line 7 reflects Rider 2 revenues related to special purpose facilities
11 supported by Company Witness Maroun.

12
13 Comparing the projected twelve months ending December 31, 2025 revenue of
14 \$5,465.4 million to the 2022 normalized revenue of \$5,177.0 million, results in an
15 increase in projected revenue of \$288.4 million as shown on page 1 of Exhibit A-
16 13, Schedule C3, line 8.

17

18 **Q59. How was the Fuel and Purchased Power Expense portion of DTE Electric's**
19 **operating expense developed?**

20 A59. Line 3 of Exhibit A-13, Schedule C1, contains DTE Electric's fuel and purchased
21 power expense for the forecast period as supported by Witness Willis on Exhibit
22 A-13, Schedule C4. The change in fuel and purchased power expense is due to a
23 decrease in sales volumes, and lower MISO purchase prices for customers on rates
24 R10 and R3, partially offset by non-capacity charges for customers on rate D13.
25 This decrease in expense is offset by a decrease in projected revenue. As previously

Line
No.

1 discussed, I adjusted the historical period to eliminate items captured in the PSCR
2 as shown on Exhibit A-3, Schedule C17. Any actual under or over recoveries of
3 fuel and purchased power will be reconciled in DTE Electric's annual PSCR filings.

4

5 **Q60. How was the O&M Expense portion of DTE Electric's operating expense**
6 **developed?**

7 A60. To determine the projected test year O&M expenses for the instant case, DTE
8 Electric started with actual year ended December 31, 2022 results normalized for
9 unusual, non-recurring items and eliminations/reclassifications for ratemaking
10 purposes. The normalized O&M amounts were then escalated for the effects of
11 inflation and adjusted to reflect anticipated material changes. Line 4 of Exhibit A-
12 13, Schedule C1, contains DTE Electric's O&M expenses for the forecasted period.

13

14 In addition to me, Witnesses Guillaumin, Milo, Davis, Kryscynski, Bellini, Steudle,
15 Farrell, Hatsios, Sparks, Hartwick, Bennett, and Fix and Hooper ~~Cooper~~ support
16 the O&M expenses and describe them in their direct testimony. These witnesses
17 also support the changes from the historic to the projected period within their
18 respective areas. I support the inflation rates used in their projections. I support
19 the Corporate Staff Group forecast and will explain the details later in my
20 testimony. I also developed Injuries and Damages expense and Environmental
21 Remediation costs based on an historical average. I have summarized the
22 development of the forecasted O&M expenses in Exhibit A-13, Schedule C5.

23

24 **Q61. How did you develop the inflation rates?**

Line
No.

1 A61. As shown on Exhibit A-13, Schedule C5.15, I have calculated a composite inflation
2 rate based on a labor factor and a non-labor factor. The inflation rate of 3% for
3 internal labor is supported by Witness ~~Fix~~Cooper. I assumed the same rate for
4 contract labor since a portion of our contract workforce comes from the same
5 unions as the DTE union employees. The inflation rate for non-labor costs is based
6 on a consumer price index (CPI)-Urban published by S&P/IHS Markit. I used the
7 labor and non-labor rates to calculate a composite rate of inflation for 2023, 2024,
8 and 2025 as shown on line 15.

9

10 **Q62. Why are you using a 3% inflation rate for labor rather than the CPI?**

11 A62. As discussed by Witness ~~Fix~~Cooper, DTE Electric's labor costs are driven by either
12 contracts that cover the Company's represented employees or market-based pay
13 practices, and thus are not directly tied to CPI. To forecast future labor costs, it is
14 more appropriate to use a specific and known wage factor rather than an overall
15 measure of inflation.

16

17 **Q63. What is the projected change in O&M Expense from the historic normalized**
18 **amount to the projected period twelve-months ending December 31, 2025?**

19 A63. Line 4 of Exhibit A-13, Schedule C1, column (d), shows the projected change in
20 O&M increasing expense by \$42.5 million. The increase is due primarily to
21 inflation, uncollectible accounts expense, Blue Water Energy Center operations,
22 and marketing programs. These are partially offset by reductions related to steam
23 plant closings, lower nuclear project (PERC) expense and lower nuclear outage
24 accruals.

25

Line
No.

1 **Q64. Did you provide any inputs to the other DTE Electric witnesses' O&M**
2 **projections?**

3 A64. Yes. I am proposing that the deferral of negative Other Post Employment Benefit
4 cost (OPEB) and Pension expense, as supported by Witnesses Fix and
5 Hooper~~Cooper~~, be continued in this case, and support the amortization of
6 previously deferred balances. I am also sponsoring the amortization of the PERC
7 regulatory asset reflected on Witness Davis's O&M exhibit, the amortization of
8 deferred Advanced Distribution Management System (ADMS) program costs on
9 Witness Kryscynski's O&M exhibit, the amortization of the Advanced Customer
10 Pricing Pilot (ACPP) and Time of Day (TOD) regulatory assets on Witness
11 Hastings's O&M Exhibit, and the amortization of deferred program costs for
12 Charging Forward on Witness Bennett's O&M exhibit.

13

14 **Q65. Can you explain the adjustment you made to Witness HCooper's forecast for**
15 **OPEB costs?**

16 A65. Yes. Witness ~~€~~HCooper has forecasted retiree health care costs including DTE
17 Electric's traditional OPEB plan. Since OPEB costs have been negative, a deferral
18 to a regulatory liability was approved by the Commission in Case Nos. U-17767,
19 U-18014, U-18255, U-20162, U-20561, U-20836, and U-21297. I have reflected
20 the continued deferral of the negative net OPEB expense on Witness ~~€~~HCooper's
21 Exhibit A-13, Schedule C5.12.2, line 18, consistent with prior treatment. If net
22 OPEB expense becomes positive in the future, then the expense will be charged
23 against the regulatory liability. In addition, in Case No. U-21297, the Commission
24 ordered that the Company must amortize the OPEB regulatory liability of \$128.4
25 million as of the historical test year (December 2022) over a seven-year period. I

Line
No.

1 have reflected the amortization of the OPEB regulatory liability on Witness
2 ~~€~~Hooper's Exhibit A-13, Schedule C5.12.2 line 19.

3

4 **Q66. Did you make an adjustment to Witness Fix's ~~Cooper's~~ forecast for pension**
5 **costs?**

6 A66. Yes. A pension expense deferral mechanism was approved by the Commission in
7 Case Nos. U-20836 and U-21297. I have reflected the deferral of the negative net
8 pension expense on Witness Fix's ~~Cooper's~~ Exhibit A-13, Schedule C5.12.1, line
9 20. If net pension expense becomes positive in the future, then the expense will be
10 charged against the regulatory liability.

11

12 **Q67. How does the capitalization of Pension and OPEB costs impact Witnesses Fix**
13 **and Hooper's ~~Cooper's~~ forecasted expense?**

14 A67. Exhibit A-13, Schedules C5.12.1 and C5.12.2, sponsored by Witnesses Fix and
15 Hooper~~Cooper~~, detail the components of Pension and OPEB costs. Each schedule
16 has a reconciliation of total cost to expense. A portion of the service cost
17 component is capitalized to CWIP/Plant based on the related labor capitalized.
18 Effective in 2018, the non-service cost components cannot be charged to capital
19 under GAAP. Instead, the non-service costs that would have been capitalized under
20 the traditional accounting treatment (but expensed under GAAP) are being recorded
21 to a regulatory asset (or liability if cost is negative) instead of plant. The regulatory
22 asset or liability is depreciated using the prior year's composite depreciation rate
23 for plant in service, with the expense recorded to a unique account within
24 Depreciation and Amortization expense. This treatment, approved in Case No. U-

Line
No.

1 18255, results in recognizing the same expense and rate base that would have
2 occurred under the historical accounting and ratemaking method.

3 **Q68. How does this impact Witness es Fix and Hooper's ~~Cooper's~~ exhibits?**

4 A68. The regulatory treatment is reflected on line 18 and line 16 of Witness es Fix and
5 Hooper's ~~Cooper's~~ Exhibit A-13, Schedules C5.12.1 and C5.12.2, respectively.

6 The amount previously shown as capitalized to plant has been bifurcated into two
7 lines. Line 17 of C5.12.1 and line 15 of C5.12.2 represents the capitalized service
8 costs recorded to CWIP/Plant, and line 18 of C5.12.1 and line 16 of C5.12.2
9 represents the capitalized non-service costs which are now recorded to a regulatory
10 asset or liability.

11

12 **Q69. Can you explain the adjustment you made to Witness Davis's O&M forecast?**

13 A69. Yes. The Commission previously approved the deferral of certain nuclear project
14 (PERC) costs above a base amount of \$15 million in Case No. U-20561. The base
15 expense is shown on Witness Davis's Exhibit A-13, Schedule C5.3, line 21, along
16 with \$4.9 million of PERC amortization expense on line 22, which represents a
17 decrease of \$11.4 million from the historical period.

18

19 **Q70. How did you calculate the adjustment to PERC amortization expense on**
20 **Witness Davis's O&M exhibit?**

21 A70. The calculation of the deferral and related amortization expense is shown on my
22 Exhibit A-13, Schedule C5.17. Lines 2 through 4 show the difference between
23 PERC actual and forecasted expenses and the \$15 million base amount. The PERC
24 deferral amounts on line 4 are amortized over the subsequent five years. Lines 7
25 through 14 show the annual expense for each vintage year and the total amortization

Line
No.

1 that will occur in the projected period on line 15. The projected period amount of
2 \$4.9 million is carried to Witness Davis's Exhibit A-13, Schedule C5.3, line 22,
3 column (n). The projection adjustment of \$11.4 million in column (l) is simply the
4 difference between the forecasted amortization expense and the actual historical
5 expense.

6

7 **Q71. Can you explain the adjustment you made to Witness Kryscynski's forecast?**

8 A71. Yes. In Case No. U-20162, the Commission approved the deferral of certain O&M
9 costs related to the ADMS software project to a regulatory asset. The deferred costs
10 include consulting and process reviews, process development, training, and
11 software fees while the system is under development, with the amounts shown on
12 capital Exhibit A-12, Schedule B5.4, page 1, line 25, sponsored by Witness
13 Hartwick. The regulatory asset will be amortized over a fifteen-year period
14 beginning with the year after the system in-service date. The final components of
15 the ADMS software project were placed in service in February 2023. As shown on
16 Witness Kryscynski's O&M Exhibit A-13, Schedule C5.6, line 12, column (j), the
17 amortization expense is expected to be \$1.2 million in the projected test period.
18 The calculation of the amortization expense is shown on my Exhibit A-13, Schedule
19 C5.6.2.

20

21 **Q72. What other change did you make to Witness Kryscynski's forecast?**

22 A72. A forecast adjustment of \$5.0 million related to a change in the Company's
23 capitalization policy related to pole inspection costs is included within Witness
24 Kryscynski's O&M Exhibit A-13, Schedule C5.6, line 20, column (j). (See exhibit
25 footnote number 6.) As explained in Case No. U-21297, the Company has

Line
No.

1 reviewed and updated its policy related to pole inspection and testing costs.
2 Effective January 1, 2023, the Company no longer capitalizes pole inspection and
3 testing costs. As a result, Witness Kryscynski has included a projection adjustment
4 to Account 593 Maintenance of Overhead Lines in the amount of \$5.0 million on
5 Exhibit A-13, Schedule C5.6, line 20, column (j) to reflect inspection costs in
6 O&M. This amount is supported by Witness Elliott Andahazy on Exhibit A-12,
7 Schedule B5.4.8

8

9 **Q73. To which programs does the \$5.0 million adjustment relate?**

10 A73. Pole inspection and testing costs have historically been included in Distribution
11 capital expenditures on Exhibit A-12, Schedule B5.4, page 13, within the two
12 programs “4.8 kV Hardening” (line 12) and “Pole and Pole Top Maintenance and
13 Modernization (PTMM)” (line 13). Witness Elliott Andahazy has detailed the costs
14 for these two programs including inspection and testing costs on Exhibit A-12,
15 Schedule B5.4.8. The Hardening program includes \$1.1M inspection and testing
16 costs in 2025 on line 2, column (e). The PTMM program includes \$3.9 million
17 inspection and testing costs in 2025 on line 9, column (e). The amounts are being
18 reclassified out of capital expenditures on line 6 and 14, column (e), and a
19 projection adjustment for the same amount is included on Witness Kryscynski’s
20 Exhibit A-13, Schedule C5.6.

21

22 **Q74. Can you explain the adjustments you made to Witness Bennett’s forecast?**

23 A74. Yes. In Case No. U-20162, the Commission approved the Company’s original
24 Charging Forward program intended to develop infrastructure related to electric
25 powered vehicles and the costs for the program are to be deferred to a regulatory

Line
No.

1 asset. In Case Nos. U-20935, U-20836, and U-21297 the Commission approved
2 additional components to the Charging Forward program. Per the Order in Case
3 No. U-20561, audited costs will be amortized over five years, beginning with their
4 inclusion in base rates. Witness Bennett supports the costs for the program shown
5 on her Exhibit A-12, Schedule B5.9. I show the calculation of the amortization
6 expense on my Exhibit A-13, Schedule C5.9.1. Line 2 of my Exhibit shows the
7 regulatory asset expenses supported by Witness Bennett. Lines 5 through 10
8 calculate the amortization by vintage year for the test period of \$3.6 million. This
9 amount is carried to Witness Bennett's O&M Exhibit A-13, Schedule C5.9, line 11,
10 column (k).

11

12 **Q75. Can you explain the adjustments you made to Witness Hatsios' forecast?**

13 A75. In Case No. U-20162, the Commission approved the Company's Advanced
14 Customer Pricing Pilot (ACPP) and authorized the deferral of up to \$7.3 million of
15 one-time implementation costs. Additionally, in Case No. U-20836, the
16 Commission approved a request for regulatory asset treatment for certain
17 implementation costs associated with the Company's Time of Day (TOD) rate
18 offering effective in November 2022. The costs for these projects are supported by
19 Witnesses Hatsios and Bennett on Exhibit A-13, Schedule C5.9.2. The deferred
20 costs are being amortized over five years. I show the calculation of \$1.3 million of
21 ACPP amortization expense for vintage years 2019 through 2022 on my Exhibit A-
22 13, Schedule C5.9.3, line 6. I show the calculation of \$1.7 million of TOD
23 amortization expense for vintage years 2022 through 2023 on line 7. The sum of
24 the ACPP and TOD amortization costs of \$3.0 million is carried to Witness Hatsios'
25 O&M Exhibit A-13, Schedule C5.7, line 8, column (k).

Line
No.

1

2 **Q76. How was the Depreciation and Amortization Expense portion of DTE**
3 **Electric's operating expense developed?**

4 A76. Line 5 of Exhibit A-13, Schedule C1, contains DTE Electric's depreciation and
5 amortization (D&A) expenses for the forecasted period. D&A includes book
6 depreciation, which is based on existing plant balances, plus new capital
7 expenditures and assumed retirements, using a half year convention. Depreciation
8 expense is calculated using the rates authorized by the Commission in Case No. U-
9 18150.

10

11 **Q77. What is the projected change in D&A Expense from the historic normalized**
12 **amount to the projected period?**

13 A77. Exhibit A-13, Schedule C1, column (d) shows the projected change in D&A,
14 increasing expense by \$210.1 million. Schedule C6 of this exhibit shows the
15 development of the projected period ending December 31, 2025, D&A expense of
16 \$1,266.2 million from the 2022 normalized D&A expense of \$1,056.2 million.
17 Depreciation is projected to increase by \$254.0 million for capital in-service
18 movement across all tangible plant categories, with the largest drivers being
19 distribution and general plant. The increase is also driven by approximately \$47.6
20 million due to reclassifying \$2.1 billion of Monroe generation net plant to a
21 regulatory asset effective December 31, 2024. The increases are offset by \$65.7
22 million from plant retirements, with the largest driver being steam plant.
23 Additionally, software amortization decreases by \$25.6 million in the projected
24 period.

25

Line
No.

1 **Q78. Why are you reclassifying \$2.1 billion of Monroe generation net plant to a**
2 **regulatory asset?**

3 A78. The Commission approved a settlement agreement in the Company's Integrated
4 Resource Plan (IRP) in Case No. U-21193 by its Order dated July 26, 2023. Among
5 other things, the Order requires the Company to securitize approximately \$845
6 million after the retirement of the Monroe Power Plant, expected in 2032. The
7 portion of the plant to be securitized will remain classified within plant in service
8 until it is retired. The balance of the plant not being securitized is to be recovered
9 as a regulatory asset over fifteen years. Therefore, approximately \$2.1 billion will
10 be reclassified from plant in service to a regulatory asset effective December 31,
11 2024.

12

13 **Q79. Can you explain the \$47.6 million impact from the Monroe regulatory asset?**

14 A79. Yes. As shown on Exhibit A-13, Schedule C6, line 8, the amortization of the
15 Monroe regulatory asset over a 15-year period is forecasted at \$144.1 million. The
16 amortization is separately calculated and supported on my Exhibit A-12, Schedule
17 B4.4. This is partially offset by \$96.5 million of lower depreciation expense
18 included within line 2. The reduction results from the cessation of depreciation on
19 \$3.4 billion of gross plant reclassified to the regulatory asset. (As previously
20 mentioned, the *net* plant balance being reclassified is \$2.1 billion.) I will explain
21 the derivation of the regulatory asset in the balance sheet forecast portion of my
22 testimony.

23

Line
No.

1 **Q80. What is the amortization of Demand Response (DR) on line 9 of Exhibit A-13,**
2 **Schedule C6?**

3 A80. The historical period reflects a credit for under-recovered 2019 DR costs approved
4 by the MPSC in Case No. U-20793. In Case No. U-20836, the MPSC approved
5 recovery of the \$3.0 million DR 2019 regulatory asset over three years. As
6 subsequently discussed regarding the regulatory asset on the balance sheet, the
7 MPSC has also issued orders in the DR 2020 and DR 2021 reconciliation cases.
8 The projected period reflects the amortization of the 2019, 2020, and 2021 balances
9 over three years.

10

11 **Q81. What is the amortization of Capitalized Pension and OPEB on lines 10 and 11**
12 **of Exhibit A-13, Schedule C6?**

13 A81. As I previously discussed regarding Witness Hooper's exhibits, the non-service
14 cost components of pension and OPEB costs are being charged to a regulatory asset
15 or liability instead of to plant. These items are expensed using the composite
16 depreciation rate for plant in service.

17

18 **Q82. What plant retirements have been forecasted?**

19 A82. Steam plant retirements are forecasted at \$260.2 million from January 2023 to
20 December 2025. Approximately \$612.0 million of scheduled retirements of
21 computer equipment and amortizable plant are assumed. I am also estimating
22 approximately \$467.1 million in annual routine retirements based on recent history
23 of other depreciable plant.

24

25 **Q83. How does DTE Electric account for the plant retirements?**

Line
No.

1 A83. The original cost is credited out of plant in service and debited to accumulated
2 depreciation. This treatment is prescribed by the Uniform System of Accounts
3 Electric Plant Instruction number 10 (F) which states, "The book cost less net
4 salvage of depreciable electric plant retired shall be charged in its entirety to
5 Account 108, Accumulated provision for depreciation and amortization."

6

7 **Q84. What is the projected change in Property Tax Expense?**

8 A84. Line 6 of Exhibit A-13, Schedule C1, column (d) shows that the total projected
9 change in property tax expense is an increase of \$62.9 million due primarily to
10 increases in plant balances. Witness Wisniewski explains the changes and supports
11 the amount on Exhibit A-13, Schedule C7.1.

12

13 **Q85. What is the projected change in Other Tax Expense?**

14 A85. Line 7 of Exhibit A13, Schedule C1, column (d) shows that the total projected
15 change in other tax expense is an increase of \$4.0 million. Witness Wisniewski
16 explains the changes and supports the amount on Exhibit A-13, Schedule C7.

17

18 **Q86. What is the projected change in State and Local Income Tax expense?**

19 A86. Line 8 of Exhibit A-13, Schedule C1, column (d) reflects a \$5.4 million decrease
20 in state and local tax expense, including Michigan Corporate Income Tax (MCIT)
21 and municipal income taxes. Witness Wisniewski explains the changes and
22 supports the amount on Exhibit A-13, Schedules C9 and C10.

23

24 **Q87. What is the projected change in Federal Income Tax Expense from the historic**
25 **normalized amount to projected period?**

Line
No.

1 A87. The change in federal income tax increases expense by \$80.4 million as shown on
2 Line 9 of Exhibit A-13, Schedule C1, column (d). Witness Wisniewski explains
3 the changes and supports the amount on Exhibit A-13, Schedule C8.

4

5 **Q88. How did you compute Operating Income?**

6 A88. Operating Revenues minus Operating Expenses yields Operating Income shown on
7 line 12 of Exhibit A-13, Schedule C1. Operating Income is projected to increase
8 due to higher revenues from a full year of new base rates in Case No. U-21297,
9 effective December 2023. The increase in revenues is partially offset by increased
10 O&M, depreciation and property taxes related to capital additions, and increased
11 income taxes.

12

13 **Q89. What information is contained on the income statement line items below**
14 **Operating Income?**

15 A89. Lines 14 and 15 on Exhibit A-13, Schedule C1, represent items that are includable
16 for ratemaking, but fall below the calculation of NOI on the income statement. Line
17 14 reflects AFUDC related to capital expenditures carried from Exhibit A-13,
18 Schedule C11. It has two components. The first is an AFUDC offset equal to the
19 amount of AFUDC included in CWIP (line 6 of Schedule C11). The second
20 component removes the return on the AFUDC embedded in CWIP (line 7 of
21 Schedule C11). This additional credit results in a revenue requirement of zero for
22 the AFUDC eligible projects within CWIP and is calculated on Exhibit A-13,
23 Schedule C11.1.

24

Line
No.

1 Consistent with past practice, the loss on reacquired debt results from the early
2 redemption of securities, which are refinanced with lower cost issues. Line 15 of
3 Schedule C1 is the annual amortization of losses on debt reacquired in prior periods.
4 The forecast does not reflect additional early redemptions. Finally, line 17 of
5 Schedule C1 provides Adjusted Net Operating Income. Adjusted NOI is projected
6 to decrease from the historical test period due to the factors that impact Operating
7 Income, offset by higher AFUDC.

8

9 **Q90. How does AFUDC impact the Company's revenue requirement and**
10 **deficiency?**

11 A90. AFUDC represents the financing costs incurred while projects are under
12 construction. Such costs are added to the asset being constructed with a
13 corresponding credit to the income statement. AFUDC is generally applied to
14 projects greater than \$50,000 and lasting more than six months. The accrual of
15 AFUDC ceases once the asset is complete and placed in service. Including the
16 credit to income from AFUDC offsets the impact of including CWIP in rate base
17 and therefore, projects that do not go into service during the projected test period
18 have no impact on the Company's revenue requirement and deficiency.

19

20 **Q91. What impact should a disallowance of projects that do not go into service**
21 **during the projected test period, on which AFUDC is accrued, have on the**
22 **Company's requested rate relief?**

23 A91. Such disallowances should not have any impact. To ensure that is the result, either
24 the proposed disallowances for projects not going into service should be excluded
25 from any reductions to rate base approved by the Commission, or a corresponding

Line
No.

1 adjustment (reduction) in pre-tax AFUDC should be added to offset the removal of
2 the projects from approved rate base.

3

4 **Q92. What is the projected period NOI amount shown in Exhibit A-13, Schedule**
5 **C1?**

6 A92. Line 17 displays the Company's projection of the twelve months ending December
7 31, 2025 NOI of \$1,087.1 million.

8

9 **Corporate Staff Group (CSG) Costs**

10 **Q93. What is the CSG?**

11 A93. The CSG is a shared services organization, "DTE Energy Corporate Services LLC"
12 (LLC), which includes corporate staff functions. This business model provides
13 efficiencies, cost savings and enhanced governance and internal controls. Each
14 organization within the CSG provides enterprise-wide services.

15

16 **Q94. What organizations are included in the CSG?**

17 A94. The organizations within the CSG provide a variety of Administrative and General
18 (A&G) type services to the Company. These include:

- 19
- 20 • Audit Services
 - 21 • Accounting and Planning
 - 22 • Tax
 - 23 • Finance and Treasury
 - 24 • Corporate and Governmental Affairs
 - 25 • Communications
 - Corporate Offices

Line
No.

- 1 • Supply Chain
- 2 • Corporate Fleet and Facilities
- 3 • Human Resources
- 4 • Information Technology
- 5 • Legal
- 6 • Regulatory Affairs
- 7 • Environmental Management and Safety
- 8 • Project Management Organization (PMO)

9

10 **Q95. Does the LLC provide other services in addition to Corporate Services?**

11 A95. Yes. Customer Service also resides at the LLC and operates under a shared service
12 model, but their span of support is only to the regulated DTE Electric and DTE Gas
13 distribution operations versus the enterprise-wide orientation of the CSG.
14 Customer Service O&M expenses are sponsored by Witness Hatsios.

15

16 **Q96. What type of O&M expense do you support for the CSG organizations?**

17 A96. I support the CSG expense projections included in the A&G accounts on Exhibit
18 A-13, Schedule C5.10.

19

20 **Q97. Can you explain the rate case adjustments and normalizations reflected in**
21 **columns (d) and (e), respectively on Exhibit A-13, Schedule C5.10?**

22 A97. Column (d) shows rate case adjustments of \$29.2 million including the elimination
23 of costs recovered via the REP and certain excluded costs (advertising, corporate
24 memberships, political advocacy, and MGM rent expense). In addition, line 3
25 includes a reduction of \$10.2 million to remove the incentive compensation for

Line
No.

1 DTE Electric's top five executive officers. Column (e) on line 20 is an O&M net
2 decrease of \$10.7 million that includes a reduction for one-time consulting costs,
3 an increase for injuries and damages, and a reduction in incentive expense as
4 previously discussed.

5

6 **Q98. What adjustment did you make to Injuries and Damages?**

7 A98. Consistent with the method approved in Case No. U-21297 and prior cases, I used
8 a historical average to determine the projected test year amount for injuries and
9 damages to smooth out any year over year variance. The calculation is shown on
10 page 3 of Exhibit A-13, Schedule C5.10.

11

12 **Q99. What adjustment did you make to Environmental Remediation?**

13 A99. I used a five-year historical average to determine the projected test year amount for
14 environmental remediation costs consistent with the method applied in Case No.
15 U-21297. The calculation is shown on page 3 of Exhibit A-13, Schedule C5.10.

16

17 **Q100. What projected adjustments did you make to O&M as reflected in columns (g)**
18 **through (j)?**

19 A100. Increases based on the inflation rate were applied to the adjusted historical test
20 period expenses for the period January 2023 through December 2025.

21

22 **Q101. With these adjustments, what is the projected test period amount for**
23 **Administrative and General O&M expense?**

24 A101. Based on the adjustments described above, A&G expense is \$198.2 million for the
25 projected test period ending December 31, 2025.

Line
No.

1

2 **Q102. What expenses are included in account 920 on line 3?**

3 A102. Account 920 reflects internal labor costs that are allocated to DTE Electric for the
4 CSG organization.

5

6 **Q103. What type of expenses are included in account 921 on line 4?**

7 A103. The largest cost items in line 4, Office Supplies and Expenses, are for software
8 maintenance and telecommunications. Witness Sharma provides more detail on the
9 O&M expenses for the IT organization. This account also includes bank fees,
10 assessments, and utilities expense.

11

12 **Q104. What is the negative expense in account 922 on line 5?**

13 A104. Line 5 reflects the transfer of A&G costs to capital as an overhead. The amount of
14 A&G transferred is based on the percentage of total direct labor charged to capital.

15

16 **Q105. What is included in account 923 on line 6?**

17 A105. The account for Outside Services primarily includes contract labor for IT. It also
18 includes security services, janitorial services, external audit fees and consulting
19 services.

20

21 **Q106. What expenses are included in lines 7 through 18?**

22 A106. These lines are for property insurance, injuries and damages, advertising,
23 environmental remediation, rents, maintenance of general plant, and other
24 miscellaneous expenses. The historical period for these items has been adjusted
25 and normalized as previously discussed.

Line
No.

1

2 **Q107. How are the CSG cost allocations to DTE Energy companies accomplished?**

3 A107. CSG costs are first incurred and accumulated at the LLC. Each department within
4 a corporate staff organization identifies products and services it expects to provide
5 to legal entities and/or business units based on the corporate staff organization's
6 scope of work. These products and services are then analyzed to determine the
7 most appropriate measure, which represents a unit of work, to be used in
8 determining the billing of products or services being provided to DTE Electric and
9 other DTE entities, by the administrative function. This measurement mechanism
10 is called a cost driver. The cost driver, in cost accounting terms, is the unit of
11 work/output that is used to determine a formula for billing the products or services
12 to DTE Electric and other DTE entities. As departments incur expenses during the
13 year, they are accumulated in cost pools. The pools are distributed and billed to
14 DTE Electric and other DTE entities pursuant to the appropriate cost driver.

15

16 **Q108. How does this cost driver allocation process work?**

17 A108. Cost drivers represent units of work that best reflect the content of the work
18 performed. For example, the Company's payroll department within Corporate
19 Services processes paychecks. Given the transactional nature of this work, the
20 volumetric cost driver of "paychecks processed" provides the best indication of
21 work performed by this group for a specific legal entity. This department provides
22 services for DTE Electric and other DTE entities and thus, payroll processing costs
23 are billed based on the volume of paychecks processed for DTE Electric during the
24 year. Other examples within the CSG include invoices paid, number of system
25 application users, and application support hours. Cost drivers are evaluated and

Line
No.

1 established based on resource consumption. These cost driver standards and levels
2 of support are periodically reviewed and updated to reflect actual experience.

3

4 **Q109. Has this cost driver allocation methodology been reviewed by the Commission**
5 **in prior rate cases?**

6 A109. Yes. This is the same cost allocation methodology supported by DTE Electric and
7 approved by the Commission in DTE Electric's general rate cases going back to
8 Case No. U-13808, and DTE Gas's general rate cases going back to Case No. U-
9 13898.

10

11 **Q110. How has the Company billed costs for which no direct cost driver was**
12 **discernable?**

13 A110. While most costs have been billed to DTE Electric and its affiliated companies
14 based on the direct cost drivers I have described, a limited number of administrative
15 activities are shared across the enterprise that do not possess cost driver attributes
16 (a unit of work directly attributed to a legal entity), or that are incurred on behalf of
17 the parent, DTE Energy, that indirectly benefit DTE Electric. It is in these cases
18 that the Company uses the commonly accepted cost allocation methodology
19 traditionally referred to as the Massachusetts Formula (Mass Formula). The Mass
20 Formula, which utilizes a three-factor formula of gross margin, net plant, and labor
21 costs, is designed to measure relative size and complexity as a means of assessing
22 the degree of support services attributable to each individual company, within the
23 context of the broader enterprise.

24

Line
No.

1 **Q111. Has the Commission approved the use of the Mass Formula in allocating**
2 **common costs in prior cases?**

3 A111. Yes. Consistent with the cost driver methodology, the use of the Mass Formula for
4 the allocation of CSG common costs was approved by the Commission in DTE
5 Electric's prior general rate cases as well as in DTE Gas's general rate cases.
6 Examples of CSG costs that utilize the Mass Formula include certain Corporate
7 Communication, Governmental Affairs, Investor Relations, Corporate Secretary
8 activities, and DTE Energy Board of Director fees.

9

10 **Information Technology O&M**

11 **Q112. What is included in Information Technology O&M?**

12 A112. IT costs are included in A&G expense on Exhibit A-13, Schedule C5.10. IT O&M
13 consists of expenses related to project work along with on-going and base operating
14 expense not tied to specific projects. Non-project costs include software
15 maintenance, software licenses, cloud computing fees, software as a service,
16 hardware and software defect remediation, business support services, and IT
17 administration. Witness Sharma provides additional information and an exhibit
18 supporting IT O&M expenses.

19

20 **Q113. Are O&M costs for Information Technology reflected by project in the**
21 **Projected Period?**

22 A113. No. The business cases for IT projects often reflect both capital costs and O&M
23 costs so that the full cost can be reviewed when management is evaluating projects.
24 For rate case purposes, the capital costs are identified by project and supported by
25 Witnesses Sharma and Hatsios. O&M costs related to projects are provided for

Line
No.

1 informational purposes in Exhibit A-24, Schedule N3, as requested by the
2 Commission. O&M related to capital projects is a subset of the total O&M costs
3 related to IT and are not specifically forecasted in the O&M projections. Rather,
4 the O&M forecast assumes that as work related to historical projects ceases, it is
5 replaced with work on new projects. Consistent with all other A&G expense, IT
6 expense in the projected period is based on adjusted historical costs plus inflation.
7

8 **Q114. How are Information Technology expenses differentiated from capital**
9 **expenditures?**

10 A114. DTE Electric follows the FERC Uniform System of Accounts (USoA), per Title 18
11 of the Code of Federal Regulations, for its capitalization policies, in accordance
12 with the MPSC Order in Case No. U-14811. Costs which do not meet the criteria
13 for capitalization are charged to expense. Items that are expensed include work
14 during the preliminary project stage (resource allocation, performance
15 requirements, vendor identification), and work during the post implementation
16 stage (training and application maintenance); and upgrades and enhancements
17 which do not result in significant, additional functionality (bug fixes, table changes,
18 screen changes, routine logic changes). The IT capital projects supported by
19 Witnesses Sharma and Hatsios reflect only the cost of the components eligible for
20 capitalization under the Company's policy.
21

22 **Corporate Staff Capital Expenditures**

23 **Q115. What is the nature of the capital expenditures incurred by CSG functions?**

24 A115. These expenditures reflect the annual capital requirement investment levels
25 required for CSG organizations to deliver services to DTE affiliates. The largest

Line
No.

1 categories of capital expenditures relate to information technology, physical
2 infrastructure, and fleet.

3

4 **Q116. Why are these costs charged directly to DTE Electric?**

5 A116. CSG capital costs are generally incurred on behalf of all DTE affiliates. (Any
6 projects or costs specific to other entities are charged directly to that company.)
7 Thus, DTE Electric records 100% of the shared asset capital expenditures for CSG
8 organizations and then charges a capital usage fee (Shared Asset Charge) to DTE
9 affiliates for each affiliate's proportionate use of these assets which are owned by
10 DTE Electric and jointly used by the companies. For example, DTE Gas occupies
11 space in buildings owned by DTE Electric (e.g., the headquarters complex).
12 Additionally, the Corporate Services Group and Customer Service organization
13 providing services to DTE Gas or other affiliates do not own any of the assets or
14 infrastructure required to function; the assets are owned by DTE Electric. The
15 charge is comprised of the return on the assets and the related depreciation incurred
16 by DTE Electric. The capital usage fee (Shared Asset Charge) is included in other
17 operating revenue.

18

19 **Q117. How does the Shared Asset structure benefit utility customers?**

20 A117. This structure minimizes duplication of costs that would otherwise be required at
21 the individual utilities. By using the same building for multiple groups, space usage
22 can be optimized by filling up the available offices with employees from a different
23 company or department. This helps avoid having to own or rent additional
24 buildings for DTE Gas or the LLC. The same idea applies to computer
25 infrastructure and office equipment. Sharing infrastructure not only reduces

Line
No.

1 investment costs, but it also reduces operating and maintenance expenses (e.g.,
2 lighting, heating and cooling, water, janitorial services, repairs, computer
3 equipment maintenance, security). Thus, overhead costs for DTE and the
4 individual utilities are reduced.

5

6 **Q118. How is the Shared Asset cost allocated from DTE Electric to affiliates?**

7 A118. The CSG capital costs incurred by DTE Electric must be paid for by the companies
8 that utilize those assets, based on each company's proportionate share, to ensure
9 DTE Electric customers are not subsidizing costs for DTE Gas and other DTE
10 affiliates. The shared asset charge from DTE Electric to each affiliate is based on
11 cost drivers for each group of assets. Buildings and furniture are allocated based on
12 the location of employees and the cost drivers associated with the functions
13 performed by those employees. Similarly, computer systems are allocated based on
14 user headcount and their related cost drivers. For example, Customer Service
15 building and computer costs are allocated between DTE Electric and DTE Gas
16 based on their respective number of utility customers.

17

18 **Q119. How are expenditures underlying the shared asset charge reviewed for**
19 **reasonableness and prudence?**

20 A119. As outlined above, the capital investments are owned by DTE Electric; therefore,
21 the total capital investment, including return on capital and the related depreciation;
22 along with the reasonableness and prudence of the project, is reviewed in DTE
23 Electric rate cases. The review of the shared asset investments in an Electric rate
24 case also encompasses the shared asset charge (expense) to affiliates, including
25 DTE Gas. Upon approval of the investment in a DTE Electric rate case, the DTE

Line
No.

1 Electric revenue requirement is reduced by the amount it receives from affiliates
2 (Shared Asset charge), including DTE Gas, for use of the assets.

3

4 **Q120. If a shared asset investment and the associated revenue credits are approved**
5 **in a DTE Electric rate case, what should be the outcome with respect to the**
6 **corresponding expense in a DTE Gas rate case?**

7 A120. The corresponding expense should also be approved in a DTE Gas rate case as
8 reasonable and prudent. As discussed above, the total cost of the assets and the
9 shared asset charge (representing the proportionate use of the asset) to affiliates,
10 including DTE Gas, are reviewed for reasonableness and prudence by the
11 Commission in DTE Electric general rate cases. Shared asset capital projects
12 undergo the same review process in Electric rate cases as all other capital projects.
13 Once a project has been approved as reasonable and prudent in a rate case, it should
14 not be relitigated in subsequent rate cases. A review of shared asset costs and related
15 revenue credits previously approved in a DTE Electric rate case within a DTE Gas
16 rate case would be redundant, an inefficient use of Company and Commission
17 resources, and potentially result in contradictory determinations.

18

19 **Q121. What are the required adjustments for Shared Asset investments that are**
20 **disallowed by the Commission in this rate case?**

21 A121. If the Commission disallows capital related to a shared asset project, DTE Electric
22 must also reduce its projected revenue credit related to its affiliates' proportionate
23 share of those disallowed costs.

24

Line
No.

1 **Q122. What level of capital expenditures do you expect the CSG organizations to**
2 **incur?**

3 A122. Company Witness Sharma supports \$460.2 million for IT projects in the bridge and
4 projected periods on his Exhibit A-12, Schedule B5.7. I support Exhibit A-12,
5 Schedule B5.8, which provides the capital projections for physical infrastructure,
6 fleet, and other projects, totaling \$355.9 million.

7

8 **Q123. What capital expenditures are included on Exhibit A-12, Schedule B5.8, page**
9 **1, line 1, Vehicle Fleet?**

10 A123. Line 1, Fleet, represents the cost of new vehicles and power operated equipment.
11 Items such as cars, trucks, bucket trucks, trailers, and forklifts are replaced to
12 provide safe and reliable equipment as the fleet ages. The Company uses a
13 proprietary model which develops a comprehensive asset life cycle that optimizes
14 total cost of ownership. Historic ownership costs and operational data are used to
15 develop a replacement strategy specific to DTE Electric. Assets with the greatest
16 reduction to maintenance and ownership costs are chosen for replacement.

17

18 **Q124. What is Facilities Construction and Upgrade on line 2?**

19 A124. Line 2, Facilities Construction & Upgrade, includes capital maintenance and
20 replacement items such as roofs, facades, electrical, plumbing, heating and cooling
21 equipment, office space updates, elevators, and cranes. Capital maintenance
22 standards are applied to optimize life cycle costs and maintain safety. The capital
23 projects for the historical, bridge and test periods are detailed on Exhibit A-12,
24 Schedule B5.8, page 2.

25

Line
No.

1 Projects in the bridge and projected periods include \$7.4 million to repair and
2 replace elevators at various locations (lines 1 through 6 and 50); \$17.7 million to
3 complete the replacement of roofs at various buildings (lines 7 through 12 and 60);
4 \$4.4 million for required five-year façade inspection and restoration work on the
5 Walker Cisler Building (WCB) and General Office Building and \$2.2 million
6 façade restoration for other various locations (lines 21, 22 and 53); \$9.5 million to
7 replace the substation and related distribution equipment at the Walker Cisler
8 Building (line 13, previously approved in Case No. U-21297); \$9.1 million to
9 investigate and replace the substation and electrical distribution equipment that is
10 used to power the downtown campus (line 14); \$6.7 million for electrical work at
11 various locations (lines 24, 25 and 49); \$2.6 million for plumbing work at various
12 locations (line 58); \$4.8 million for overhead and pedestrian door replacements at
13 various locations (line 48); \$7.5 million for automotive lifts (line 45); \$30.6 million
14 for HVAC replacements at various locations including boilers, chillers, piping, air
15 handlers, diffusers, variable air volume boxes, and other equipment (lines 16, 17
16 and 56); \$5.1 million for updates to the fire suppression systems at the Warren
17 Service Center and other locations (lines 19 and 54); and \$5.1 million for the
18 Warren Service Center Transformer Yard reorganization and infrastructure
19 improvements (line 20, previously approved in Case No. U-21297).

20

21 Another project planned for 2023 and 2024 is office space updates at the downtown
22 campus of \$9.5 million (lines 28 through 33) to accommodate the mandatory three-
23 day return to work standards for employees starting in 2024. The Company is
24 purchasing chairs, monitors, keyboards, mice, and docking stations to re-outfit the
25 workstations in the General Office (GO) and Service Building (SB). The prior

Line
No.

1 workstation equipment in these buildings was made available to employees to
2 accommodate working from home during the COVID-19 pandemic and generally
3 continues to support remote work. We are also purchasing additional workstations
4 as needed based on employee counts. Additionally, all huddle and conference
5 rooms in the GO and SB will require audio visual equipment to be Microsoft Teams
6 enabled. In addition, the 2023 period includes \$4.8 million for renovation of the
7 first floor of the Walker Cisler Building lobby, including adding conference and
8 huddle rooms (line 27).

9
10 Furthermore, the 2023 and 2024 periods include \$7.0 million for renovation at the
11 Shelby service center (line 26) which includes asset preservation and infrastructure
12 upgrades including a new roof, removal of a septic tank and connection to the city
13 sewer system, mechanical equipment, bathroom/locker room replacement and
14 interior renovations.

15
16 Finally, the projected periods include \$21.7 million for other general construction
17 and end of life repairs and replacements, including but not limited to, equipment,
18 tools, overhead cranes, flooring, truck shelters, security, and windows.

19

20 **Q125. What is Service Center Optimization and Modernization on line 3?**

21 A125. Service Center Optimization and Modernization is a project to replace facilities that
22 have exceeded their useful life by consolidating some sites and updating other
23 existing sites to reduce the Company's overall footprint and reduce operating
24 expenses by 2025. The Commission approved this project in Case Nos. U-20162,
25 U-20561, U-20836 and U-21297. The capital projects for the historical, bridge and

Line
No.

1 test periods are detailed on Exhibit A-12, Schedule B5.8, page 3. The older facilities
2 have experienced increased costs due to aging infrastructure, and critical
3 components such as HVAC and roofs have failed. Through the consolidation of
4 locations, we will realize savings opportunities and increase efficiency within the
5 sites.

6
7 The Warren Service Center (WSC) is DTE's largest service center, supporting
8 Distribution Operations, Energy Supply, and other departments with over 300
9 people on 60 acres and 23 acres of parking lots and roadways. The WSC project,
10 which was approved in previous cases as stated above, started in 2017 to address
11 aging assets that are beyond their useful life and in a state of disrepair. It included
12 consolidating activities from two buildings into one building and constructing a
13 new lab on an existing DTE site. The WSC site work project involves
14 improvements to the 60-acre site which contains over 1,000,000 square feet of
15 paved roadways and parking lots. The site is experiencing sinkholes in the
16 roadways, collapsed storm water catch basins, and degraded paving resulting in
17 potholes and trip hazards along with inadequate site lighting to support 24/7
18 operations. The work includes replacing the main roadway, site lighting, and
19 parking lot paving to improve safety for employees and visitors (line 2). The
20 majority of the WSC site improvements were completed through 2023, with an
21 additional \$1.5 million projected in 2024. Another significant project at WSC is
22 improving building "L" at a cost of \$8.0 million, of which \$6.6 million is projected
23 from 2023 through December 2025 (line 3). Building L is an approximately 40,000
24 square foot automotive repair facility constructed in 1970. It is the largest
25 automotive repair facility at DTE and is critical to ensuring Company vehicles are

Line
No.

1 available to support our customers. The facility is experiencing automotive lift
2 failures, roof leaks, and HVAC system failures which affects the Company's ability
3 to maintain company vehicles in an efficient manner and support its customers. As
4 a result, work includes replacing the building exhaust system, five automotive lifts,
5 electrical panelboards and electrical service, the roof, the fire alarm and suppression
6 system, the HVAC system, as well as overhead doors, and lighting.

7
8 The Western Wayne Service Center (lines 7 through 10) will also be updated at a
9 cost of approximately \$24 million. The building was constructed in 1978 and many
10 building systems such as lighting, plumbing, electrical, flooring, and ceilings are
11 beyond their useful life and need replacing. The building renovation shown (line
12 7) costs approximately \$14.4 million and was previously approved in Case No. U-
13 21297. Phase 2 of this project includes expanding the fleet vehicle repair garage
14 bay and improvements to the fleet garage and warehouse (line 8). Phase 2 also
15 includes site improvements on line 9 for a parking lot expansion, stormwater
16 management, site lighting, and a perimeter security fence. Total projected costs for
17 Phase 2 (lines 8 and 9) are \$7.6 million.

18
19 Another significant project, Waterford, is on line 11. The lease on the Northwest
20 Planning Design office in Farmington was terminated in 2020 and the Pontiac
21 Service Center will close in the second half of 2024 and will be moved to a larger
22 location in Waterford. This project started in 2018 and was approved in Case Nos.
23 U-20162, U-20561, U-20836 and U-21297.

24

Line
No.

1 The Company plans to invest \$3.0 million in 2025 for storm water improvements
2 at the Ann Arbor service center (line 12). This is a preservation project for an asset
3 that is beyond useful life, at risk of failure, does not meet current municipal
4 requirements, and requires improvements to deal with more frequent storm events
5 and mitigate risk. The Ann Arbor SC parking lot has flooded various times over the
6 past several years impacting DTE Electric crews' ability to utilize the parking lot.

7
8 The Company also plans to invest approximately \$6.4 million for Service Center
9 Automated Building Control Systems upgrades (lines 13 through 22). These
10 upgrades are asset preservation projects to replace various building control systems
11 such as heating, ventilation, and air conditioning (HVAC) and lighting control
12 systems that do not meet current energy code, are beyond useful life and are at risk
13 of failure due to their condition. Technology advancements have made these
14 control systems obsolete, and the energy code requires any new design or
15 renovation to improve energy efficiency and reduce energy loss. This project will
16 provide more efficient management of these systems, reducing energy usage and
17 utilizing technology to remotely monitor and control these building systems. This
18 will enable our operations and maintenance team to remotely diagnose and address
19 building issues without having to travel to these locations, reducing waste and
20 improving response time.

21
22 Finally, the Company is also planning to invest \$7.9 million in 2023 through 2025
23 (lines 23 and 24) for costs to update the technical development center in Westland,
24 which is nearly 50 years old with many assets in need of repair. The scope of the
25 repairs includes replacing the current storm water management system due to

Line
No.

1 flooding which has affected training and property utilization; replacing parking
2 lots; and replacing building systems including HVAC, roof, and electrical systems.

3

4 **Q126. What are the projects in Security Measures on line 4 of Exhibit A-12, Schedule**
5 **B5.8 page 1?**

6 A126. Line 4 on page 1 is a project to reduce security related risks. It includes \$7.2 million
7 in 2025 for Phase III of a project started in 2019 to replace the existing physical
8 access control system (PACS) with new technology. The new PACS will be
9 combined with our logical access control system (LACS) to tie physical control at
10 our various sites to our SAP identity system. Employees were issued new high
11 assurance credential badges. Highly encrypted access control technology is being
12 installed at sites ranked through our Security Governance Risk Model. The costs
13 for this project include IT hardware and infrastructure, new badge readers, and
14 system integration.

15

16 **Q127. What items are included in line 5, Miscellaneous?**

17 A127. Line 5 includes approximately \$1.7 million in 2024 and 2025 for environmental
18 management. The Company is evaluating and developing technologies and controls
19 to provide cost effective solutions in meeting environmental compliance and energy
20 requirements. The remaining balance is for minor capital items used in the
21 Corporate Staff groups. These items are substantially offset by investment recovery
22 salvage sales.

23

24 **Q128. How much allowance for funds used during construction (AFUDC) is assumed**
25 **in the projected test period for Corporate Staff?**

Line
No.

1 A128. AFUDC for Corporate Staff is included on Exhibit A-12, Schedule B5.8 page 4.
2 As shown, the Corporate Staff AFUDC is projected to be \$1.8 million for the 12-
3 month period ending December 31, 2025. A historical trend is used to estimate
4 AFUDC on routine capital, such as the portion of Facilities, Design and
5 Construction where the mix of eligible projects is consistent year to year, while
6 AFUDC is calculated specifically on a project-by-project basis for eligible non-
7 routine projects. The authorized cost of capital rate is 5.561% per the December 1,
8 2023 Order in Case No. U-21297.

9

10 **Q129. What is provided on the schedule entitled Removal Costs, Plant in Service and**
11 **CWIP on page 5 of Exhibit A-12, Schedule B5.8?**

12 A129. This schedule provides a breakdown of plant activities which are used to forecast
13 Plant in Service, Accumulated Depreciation and Construction Work in Progress
14 (CWIP) on the projected balance sheet. Capital expenditures consistent with page
15 1 are summarized in columns (c) through (f). Column (b) includes a corresponding
16 in-service assumption: "Annual" is indicated for categories of plant spend that are
17 generally unitized within the year of spend, while a specific in-service date is used
18 for projects that remain in CWIP for more than a year before moving into Plant in
19 Service.

20

21 Column (g) includes an estimated percentage of removal costs that are included
22 within the capital expenditures. Removal costs are charged to Accumulated
23 Depreciation rather than Plant/CWIP and are therefore not depreciable. Removal
24 cost of 10% based on historical trend of removals as a component of capital
25 expenditures is applied to Electric Facilities Repairs and Replacements on line 2,

Line
No.

1 Facilities Construction and Upgrade on line 4, and Service Center Optimization
2 Projects on lines 8 through 32, except 100% is used for specific demolition projects
3 on lines 12 and 15. Finally, Investment Recovery Salvage Sales are assigned 100%
4 removal as these proceeds are credited directly to Accumulated Depreciation to
5 offset removal charges.

6
7 Columns (h) through (j) reflect calculated removal costs based on projected Capital
8 Expenditures in columns (d) through (f) multiplied by the removal cost percentage
9 in column (g). The remaining Capital Expenditures will appear in Plant in Service
10 columns (k) through (m) if in-service assumption is "Annual," or CWIP columns
11 (n) through (p) until the date of in-service as indicated in column (b). At that time,
12 cumulative spend including the historical period is transferred to in-service
13 (excluding the removal cost estimate).

14

15 **Balance Sheet Forecast**

16 **Q130. What projected test year balance sheet information are you providing?**

17 A130. Exhibit A-12, Schedules B2 and B3 provide the projected 13-month average utility
18 plant balances and depreciation reserves, respectively, compared to the historical
19 period. Schedule B4 provides the projected 13-month average working capital
20 compared to the historical period. Schedule B4.1 classifies the projected balance
21 sheet information into the categories of net plant, working capital, and the various
22 financing components.

23

24 **Q131. Can you explain the DTE Electric balance sheet on Schedule B4.2?**

Line
No.

1 A131. The electric balance sheet statement shown on Exhibit A-12, Schedule B4.2,
2 represents the DTE Electric 13-month average balance sheet for the projected year.
3 As previously stated, DTE Electric's financial statements represent DTE Electric
4 Company plus MERC.

5
6 **Q132. What are the major components making up the Assets and Other Debits**
7 **reflected in Exhibit A-12, Schedule B4.2, page 1 of 2?**

8 A132. Exhibit A-12, Schedule B4.2, page 1 of 2 has four major asset components:

- 9 1) Total Utility Plant and Property
10 2) Other Property and Investments
11 3) Current Assets
12 4) Deferred Debits

13

14 **Total Utility Plant and Property**

15 **Q133. How did you develop the projected Utility Plant and Property amount in this**
16 **case?**

17 A133. Total Utility Plant and Property on Exhibit A-12, Schedule B4.2 (lines 4 through
18 13) is comprised primarily of Net Utility Plant (line 9), which is projected to
19 increase each year resulting from annual capital expenditures being greater than the
20 annual depreciation allowance charge, partially offset by the transfer of \$2.1 billion
21 to a regulatory asset related to the Monroe power plant as required by the
22 Commission's Order in the Company's 2023 IRP proceeding, Case No. U-21193.
23 These projections reflect substantial capital expenditures primarily related to
24 distribution system replacements and reliability improvements, steam generation
25 reliability and environmental projects, nuclear main unit generator replacement and

Line
No.

1 maintenance projects, facility upgrades and maintenance, and information
2 technology investments. Page 1 of Exhibit A-12, Schedule B5 provides a
3 functional summary of DTE Electric's total projected capital expenditures. Further,
4 the various operational witnesses provide details on the capital expenditures they
5 are sponsoring.

6

7 **Q134. How did you develop the projected capital expenditure amounts DTE Electric**
8 **included in this case?**

9 A134. To determine the projected test year capital expenditure levels for this case, DTE
10 Electric started with historical amounts normalized for unusual, non-recurring
11 items. In some cases, the routine capital expenditures were escalated for the effects
12 of inflation. Capital expenditures for unique or one-time projects were individually
13 forecasted. Capital expenditures are supported by Company Witnesses Guillaumin,
14 Milo, Davis, Hill, Hartwick, Steudle, Deol, Elliott Andahazy, Bellini, Farrell,
15 Bennett, Sharma, Hatsios and me. (Removal costs included in capital expenditures
16 on the individual witness exhibits are reflected as a charge to the accumulated
17 depreciation reserve.)

18

19 **Q135. Will all the forecasted capital expenditures be unitized to plant in service by**
20 **the end of the projected test period?**

21 A135. No. The capital expenditure exhibits show which projects will not be in service
22 during the projected test period. There is no depreciation expense projected for
23 these projects, and the AFUDC credit on the income statement offsets the impact
24 of reflecting the projects in rate base. In other words, there is no current revenue
25 requirement for these projects.

Line
No.

1 **Q136. What are Removal Costs?**

2 A136. Pursuant to the Electric Plant Instructions in the Uniform System of Accounts
3 (USOA), cost of removal means the cost of demolishing, dismantling, tearing down
4 or otherwise removing electric plant. As part of Utility plant accounting, the
5 Company's depreciation rates are set to recover both the original cost and estimated
6 removal costs over the life of the asset. When removal costs are actually incurred,
7 they are charged against the accumulated depreciation balance. Any over or under
8 accrual is handled by updating depreciation rates in depreciation cases and applying
9 the new depreciation rates prospectively when they are reflected in base rates.

10

11 **Q137. What is included on page 2 of Exhibit A-12, Schedule B5?**

12 A137. To calculate the projected balance sheet, the rate case model appropriately assumes
13 the portion of capital expenditures related to removal work is charged as a debit to
14 accumulated depreciation. These costs do not get charged to CWIP/Plant and are
15 not depreciable capital expenditures. The schedule on page 2 of Exhibit A-12,
16 Schedule B5, shows the amount of removal costs included in capital expenditures
17 on page 1.

18

19 Capital expenditures from Page 1 are summarized on lines 1 through 13. Removal
20 Costs included within those Capital Expenditures are provided on lines 15 through
21 27 which are assumed charged to Accumulated Depreciation. The difference on
22 lines 29 through 41 represents the non-removal portion of capital expenditures
23 initially charged to CWIP and moved to Gross Plant once placed in service.

24

25 **Q138. What is provided on pages 3-4 of Exhibit A-12, Schedule B5?**

Line
No.

1 A138. This schedule provides the Company Summary breakdown of plant activities used
2 to forecast Plant in Service, Accumulated Depreciation and Construction Work in
3 Progress (CWIP) on the projected balance sheet. Witnesses Guillaumin, Davis,
4 Hill and I sponsor a similar schedule for Steam, Nuclear, Distribution and
5 Corporate Staff, respectively, which is displayed on lines 1 through 31, and 46
6 through 47. On lines 33 through 43 of this summary schedule, I also provide the
7 corresponding activity for Information Technology, MERC and Fuel Supply,
8 Community Lighting, Demand Side Management, and Charging Forward based on
9 assumptions provided by the sponsoring witnesses.

10

11 Capital expenditures consistent with page 1 are summarized in columns (d) through
12 (f). Column (g) through (i) includes estimated removal costs that are included
13 within those capital expenditures. To estimate cost of removal, the Company
14 assumes a standard percentage of capital expenditures related to removal costs,
15 unless the project is 100% related to removal or demolition or 0% removal related
16 to technology projects. The remaining Capital Expenditures will appear in Plant in
17 Service columns (j) through (l) if assumed in-service, or CWIP columns (m)
18 through (o) until transferred to in-service.

19

20 **Q139. What is the projected change in Total Utility Plant and Property?**

21 A139. Exhibit A-12, Schedule B4.2, line 4, reflects a plant-in-service decrease from
22 December 2022 to December 2024 of \$356.7 million. This change is due to
23 \$3,830.1 million of base capital in-service movement less \$3,422.0 million related
24 to the Monroe regulatory asset reclassification, and \$764.8 million of plant
25 retirements transferred to the depreciation reserve. The plant-in-service change

Line
No.

1 from December 2024 to December 2025 is \$1,419.2 million. This change is due to
2 \$1,993.7 million of in-service movement less \$574.5 million for plant retirements.

3
4 Plant held for future use on line 5 primarily reflects the FERMI 2 license extension
5 in the historical and interim periods. The license extension becomes effective when
6 the existing license expires on March 20, 2025, and is reclassified to intangible
7 plant within Plant in Service. (See Exhibit A-13, Schedule C6, page 2, line 21.)
8 The costs incurred to obtain the extension have been capitalized and include project
9 management; engineering planning and design; and NRC required inspections of,
10 and updates to, the physical assets. DTE Electric will incur additional costs through
11 March 2025 to complete work related to commitments made to the NRC as a
12 condition of obtaining the extension. The license extension will be amortized over
13 its 20-year service life starting in 2025.

14
15 The CWIP change on line 6 from December 2022 to December 2024 is an increase
16 of \$436.0 million. This change is primarily due to \$4,356.3 million of capital
17 expenditures offset by \$3,830.1 million of projects transferred to plant-in-service
18 and a reclass of \$90.1 million related to the Monroe regulatory asset. The CWIP
19 increase from December 2024 to December 2025 of \$287.0 million reflects
20 \$2,207.8 million of capital expenditures, less transfers to plant-in-service of
21 \$1,920.8 million. As can be seen on Exhibit A-12, Schedule B5, projected capital
22 expenditures are over \$2.5 billion annually. The largest capital expenditures are
23 related to distribution and production assets. Witness Guillaumin supports the
24 steam production investments including plant reliability and safety, coal ash
25 projects, decommissioning work, and battery projects. Witnesses Hill, Elliott

Line
No.

1 Andahazy, Hartwick, Deol, and Steudle support distribution investments including
2 emergent replacements, customer connections, infrastructure hardening and
3 redesign, and technology.

4

5 The decrease in acquisition adjustments on line 7 from December 2022 to
6 December 2025 of \$17.4 million results from amortization of the adjustment for the
7 Renaissance Power plant.

8

9 The decrease in depreciation reserve on line 8 from December 2022 to December
10 2024 of \$721.0 million is due to \$ 1,416.3 million of Monroe regulatory asset
11 reclass, \$767.3 million of removal costs and \$764.8 million of plant retirements,
12 offset by 2,227.4 million of depreciation expense. The increase of \$277.0 million
13 from December 2024 to December 2025 represents depreciation expense of
14 \$1,114.5 million partially offset by \$263.0 million of removal costs and \$574.5
15 million of plant retirements.

16

17 The change in Nuclear Fuel Property on line 12 from December 2022 to December
18 2024 is an increase of \$1.0 million from nuclear fuel purchases of \$112.0 million
19 less nuclear fuel expense of \$111.0 million. The change in Nuclear Fuel Property
20 from December 2024 to December 2025 is an increase of \$74.0 million due to fuel
21 purchases of \$135.1 million less nuclear fuel expense of \$61.1 million. Witness
22 Davis supports the nuclear fuel purchase amounts.

23

24 **Q140. Why is CWIP included in Net Utility Plant for ratemaking purposes?**

Line
No.

1 A140. CWIP is included in this rate filing as required by the Commission's May 10, 1976
2 Order in Case No. U-4771. CWIP is forecasted (in part) based on the expected in-
3 service date for large projects, when they are reclassified from CWIP to Plant in
4 Service. These projects generally include AFUDC, which is credited on the income
5 statement, reducing the revenue deficiency, and offsetting the impact of the assets
6 in rate base. AFUDC is applied to projects greater than \$50,000 and lasting more
7 than six months, with an exception for environmental and other specifically ordered
8 projects.
9
10 Per the Commission's March 14, 1980 Order in Case No. U-5281, a generic
11 proceeding on the Commission's own motion to examine the accounting treatment
12 of CWIP and AFUDC, the Commission required that pollution control related
13 CWIP should not accrue AFUDC but instead be included in rate base. This position
14 was affirmed in the Commission's August 16, 2011 Order in Case No. U-15244
15 (page 72).
16
17 CWIP also includes lower cost, short duration projects that are not eligible for
18 AFUDC. Projects involving smaller dollar assets, or mass assets, are initially
19 charged to CWIP but are soon transferred to Plant in Service. The type of work
20 included in the short duration items is generally standard and ongoing throughout
21 the year. Thus, as the prior balance for these types of assets is cleared to Plant in
22 Service, another wave of construction is adding new amounts to the CWIP balance.
23 For these types of recurring items, I forecasted CWIP based on a historical trend of
24 balances in the account.
25

Line
No.

1 **Other Property and Investments**

2 **Q141. What are you forecasting for Other Property and Investments?**

3 A141. Lines 16 and 17 are held constant at the historical 13-month average. As previously
4 discussed, the Nuclear Decommissioning Trust Fund balance on line 18 was
5 eliminated from the historical period because it does not impact base rates.

6

7 **Current Assets**

8 **Q142. What is included in Current Assets on lines 21 through 32 of Exhibit A-12,**
9 **Schedule B4.2?**

10 A142. Current assets include cash, notes and accounts receivable, uncollectible reserve,
11 unbilled revenues, fuel inventories, materials and supplies inventories,
12 prepayments, and other current assets.

13

14 **Q143. How did you forecast the balance for the various Current Assets?**

15 A143. Individual line items that fluctuate throughout the year, and for which a specific
16 forecast is not developed, were based on a 13-month historical average. These
17 items include cash, other accounts receivable, other accounts receivable-assoc.
18 companies, uncollectible reserve, unbilled revenues, and materials and supplies
19 inventory. Notes receivable and other current assets were adjusted to zero at
20 December historical and no changes were assumed in the projected period.
21 Customer accounts receivable was also based on a 13-month average historical with
22 additional forecast adjustments. Fuel inventory and prepayments were specifically
23 forecasted.

24

Line
No.

1 **Q144. How did you forecast the balance for Customer Accounts Receivable on line**
2 **24?**

3 A144. Customer Accounts Receivable was based on a 13-month weather normalized
4 historical average, adjusted for rate relief approved in Case No. U-21297.

5
6 **Q145. How did you forecast the balance for Fuel Inventory on line 29?**

7 A145. The increase in Fuel Inventory from the historical period reflects additional fuel
8 inventory at Monroe to support operations.

9
10 **Q146. How did you forecast the balance for Prepayments on line 31?**

11 A146. Prepayments primarily represents property taxes. The change is based on
12 forecasted accruals and payments.

13
14 **Deferred Debits**

15 **Q147. What is included in Deferred Debits on lines 35 through 68 of Exhibit A-12,**
16 **Schedule B4.2?**

17 A147. This section contains various regulatory assets and deferred tax items.
18 Unamortized Debt Expense on line 35 is increased by projected issuance expense
19 of \$24.9 million assumed at 1% of new debt issues offset by annual straight-line
20 amortization of approximately \$4.7 million. Unamortized Loss on Reacquired Debt
21 on line 36 is reduced by annual straight-line amortization of approximately \$2.7
22 million. These balances are tied to specific debt issues and are amortized over the
23 life of the issues.

24
25 **Q148. What is the prepaid pension asset on line 38?**

Line
No.

1 A148. Pension costs recognized by the Company are reflected in a pension liability
2 account. However, when contributions to the pension trust are made, they reduce
3 the liability. To date, the Company has funded more than it has recorded as a
4 pension liability, resulting in a net debit balance, referred to as the prepaid pension
5 asset. The prepaid pension asset represents the cumulative difference between the
6 pension cost recognized by the Company and the Company's contribution to its
7 pension trust. Specifically, when the Company's annual contributions exceed
8 annual pension cost, the prepaid pension asset increases; and when the Company's
9 annual contributions are less than the annual pension costs, the prepaid pension
10 asset decreases. The pension plans and related pension costs are explained by
11 Witness ~~Fix~~Cooper.

12

13 **Q149. Does the prepaid pension asset reflect any funding during the projected**
14 **period?**

15 A149. No. However, it does include a transfer of pension assets of \$50 million from the
16 DTE Gas non-union plan in 2023.

17

18 **Q150. Why did DTE Gas transfer \$50 million to the DTE Electric pension plan?**

19 A150. As of December 31, 2022, the DTE Gas Non-Union pension plan had assets in
20 excess of its projected benefit obligation (PBO) of about \$137 million, whereas the
21 DTE Electric pension plan had assets that were about \$387 million less than its
22 PBO. Since the DTE Gas Non-Union pension plan is a component of the overall
23 DTE Energy Retirement plan, as is the DTE Electric pension plan, the Company
24 can transfer the excess assets in the DTE Gas Non-Union plan to DTE Electric
25 without any income tax or ERISA consequences. Funding the pension plan

Line
No.

1 increases the return generated from plan assets, which will reduce pension costs
2 over time. This transfer was accomplished through a payment by DTE Electric of
3 \$50 million in 2023 to DTE Gas in consideration for the transfer of DTE Gas trust
4 assets of \$50 million in 2023 within the DTE Energy Retirement plan trusts.

5

6 **Q151. What is the Reg Asset – Pension Deferral on line 40 of Exhibit A-12, Schedule**
7 **B4.2?**

8 A151. The regulatory asset was established pursuant to the Commission’s order in Case
9 No. U-20836 that approved a pension expense deferral mechanism. Effective with
10 the Order, actual pension expense is deferred as a regulatory asset if positive or a
11 regulatory liability if negative. The regulatory asset balance reflects the deferral of
12 the Company’s projected pension expense as further described by Witness
13 ~~Cooper~~.
14

15 **Q152. Why is there an item called “Monroe Regulatory Asset” on line 41 of Exhibit**
16 **A-12, Schedule B4.2?**

17 A152. As previously discussed, the July 26, 2023 Order in the Company’s IRP in Case
18 No. U-21193 requires (among other things) the Company to securitize
19 approximately \$845 million after the retirement of the Monroe Power Plant,
20 expected in 2032. The portion of the plant to be securitized will remain classified
21 within plant in service until it is retired. The balance of the plant not being
22 securitized is to be recovered as a regulatory asset over fifteen years.

23

24 **Q153. Why does the Monroe Regulatory Asset have a zero balance on line 41?**

Line
No.

1 A153. The Order in Case No. U-21193 requires the overall return on the regulatory asset
2 to reflect a return on equity of 9%. To accomplish this, I have excluded the
3 regulatory asset from the balances underlying the base rate revenue deficiency
4 calculations. A separate rate of return for the Monroe regulatory asset is supported
5 by Witness Vangilder on Exhibit A11, Schedule A1.2.

6

7 **Q154. How was the Monroe Regulatory Asset balance calculated?**

8 A154. Refer to Exhibit A-12, Schedule B4.5. The total Monroe plant balance forecasted
9 for December 31, 2024 is \$3.2 billion as shown in column (a), line 9. To determine
10 how much of this should be reclassified to the regulatory asset, I had to subtract the
11 2024 amount that will remain in plant and eventually be securitized after the plant
12 is retired in 2032. Lines 13 through 16 calculate the 2024 amount that will result
13 in the agreed upon securitization value of \$845 million in 2032. That amount is
14 \$1.1 billion as shown on line 16. The \$1.1 billion will remain in plant and be
15 depreciated at 2.82% based on authorized depreciation rates. This results in a net
16 plant balance of \$845 million on December 31, 2032, as proven out in columns (c)
17 through (k). Subtracting the \$1.1 billion to be securitized from the \$3.2 billion total
18 plant balance, results in the \$2.1 billion net plant amount to be reclassified to the
19 regulatory asset, as shown in column (b). This amount is carried to Exhibit A-12,
20 Schedule B4.4, line 3.

21

22 **Q155. How is the Monroe regulatory asset calculated on Exhibit A-12, Schedule**
23 **B4.4?**

24 A155. The beginning balance on line 3 is carried from Exhibit A-12, Schedule B4.5. In
25 column (d), capital additions and amortization for 2025 are shown on lines 5 and 6.

Line
No.

1 Per the Case No. U-21193 July 26, 2023 IRP Order, capital additions approved in
2 rate cases will be added to the regulatory asset. Witness Guillaumin supports the
3 capital expenditures which are shown on Exhibit A-12, Schedule B5.1, page 2. The
4 amortization is calculated based on a fifteen-year period per the Case No. U-21193
5 July 26, 2023 IRP Order. After reflecting the additions and amortization, the
6 projected ending balance for 2025 is shown on column (d), line 7. The simple and
7 thirteen-month averages are shown in column (f). The thirteen-month average from
8 column (f) line 8 is used by Witness Vangilder on his Exhibit A-11, Schedule A1.2
9 to calculate the return.

10

11 **Q156. What is the Ludington Regulatory Asset on line 42?**

12 A156. On May 18, 2023 the Commission approved a joint application by DTE Electric
13 and Consumers Energy in Case No. U-21310 to defer certain costs at the Ludington
14 Pumped Storage Plant resulting from defective work by a third party. The balance
15 represents costs deferred during 2023 after receipt of the Order.

16

17 **Q157. How was the Customer 360 Regulatory Asset on line 44 developed?**

18 A157. The Company implemented a new Customer Relationship and Billing system in
19 April 2017 called Customer 360. Pursuant to the September 26, 2016 Order in Case
20 No. U-17666, the Company deferred \$47 million for certain project expenses in
21 Account 182.3, Other Regulatory Assets. The Company also incurred \$16.6
22 million of post implementation costs during 2017. The Commission approved
23 recovery of the 2017 amount in Case No. U-20162. The deferred costs are being
24 amortized over a 15-year period, and the balance reflects annual amortization of
25 about \$4.2 million.

Line
No.

1

2 **Q158. What is the Residential Income Assistance regulatory asset on line 46?**

3 A158. In Case No. U-20561, the Commission authorized DTE Electric to defer Residential
4 Income Assistance (RIA) and Low-Income Energy Assistance credits above a base
5 amount. The balance reflects that in 2022, the Company issued more RIA credits
6 to customers than were reflected in the base. In Case No. U-20836, the Commission
7 ordered any unspent RIA and LIA be recorded as a regulatory liability. Effective
8 with the Order in U-20836, any underspent amounts will be netted against any
9 regulatory assets recorded for overspent amounts. The projected balances were
10 based on a 13-month historical average.

11

12 **Q159. What is the Program Evaluation & Review Committee (PERC) regulatory**
13 **asset on line 47?**

14 A159. This balance represents deferred costs for certain nuclear O&M projects. As further
15 explained by Witness Davis, the Company executes PERC operations and
16 maintenance projects. The change in balance is projected based on the addition of
17 deferred costs less the amortization of deferred amounts over five years, as shown
18 on my Exhibit A-13, Schedule C5.17. As previously discussed, the Order in Case
19 No. U-18014 provided deferral treatment for any expenses over or under a \$4.9
20 million base amount, and the base was increased to \$15 million in Case No. U-
21 20561.

22

23 **Q160. What is the Advanced Distribution Management System (ADMS) regulatory**
24 **asset on line 48?**

Line
No.

1 A160. As previously discussed, the Company is installing an ADMS. The Commission
2 approved deferral of certain O&M costs as a regulatory asset with amortization over
3 fifteen years in Case No. U-20162. As shown on Exhibit A-12, Schedule B5.4,
4 page 1 of 26, line 25, these expenses were deferred in the amount of \$4.7 million
5 in the 2022 historical year and are projected to be \$3.6 million in the bridge period.
6 The regulatory asset balance is reduced by annual amortization of approximately
7 \$1.2 million in 2024 and 2025.

8

9 **Q161. What is the Charging Forward Regulatory Asset on line 49?**

10 A161. As previously discussed, in Case Nos. U-20162 and U-20935 the Commission
11 approved a program called Charging Forward to incentivize third parties to build
12 charging stations for electric vehicles by providing rebates. Per the Order, the
13 regulatory asset will be expensed over five years, concurrent with its inclusion in
14 base rates. Additionally, the Company requested, and received approval for, an
15 expansion of the Charging Forward program in Case Nos. U-20836 and U-21297.
16 The Orders provide for the same regulatory asset treatment for rebates paid to
17 schools, municipalities, gas stations, and similar customers. The projected balance
18 of \$47.1 million at December 2025 reflects deferred expense through the projected
19 period, supported by Witness Bennett, less cumulative amortization.

20

21 **Q162. What is the Advanced Customer Pricing Pilot Regulatory Asset on line 51?**

22 A162. Regulatory Asset treatment for certain implementation costs for the ACPP was
23 approved in the Commission's November 14, 2019 Order in Case No. U-20602.
24 The Commission approved deferral of up to \$7.3 million of costs. Actual costs

Line
No.

1 deferred totaling \$6.6 million are supported by Witnesses Bennett and Hatsios on
2 Exhibit A-13, Schedule C5.9.2, less cumulative amortization.

3

4 **Q163. What is the Time of Day (TOD) Regulatory Asset on line 52?**

5 A163. Regulatory Asset treatment for certain implementation costs for the Company's
6 Time of Day rate offering was approved in the Commission's November 18, 2022
7 Order in Case No. U-20836. The Company proposed a full implementation of TOD
8 rates, and the project incurred both capital and O&M expenses. The balance as of
9 December 2025 on line 52 of \$4.9 million reflects \$8.5 million of one-time
10 implementation costs offset by \$3.5 million of cumulative amortization expense
11 through the projected period. Witnesses Bennett and Hatsios support one-time
12 implementation costs on Exhibit A-13, Schedule C5.9.2.

13

14 My Exhibit A-13, Schedule C5.9.3 supports the calculation of annual amortization
15 expense of \$3.0 million for both the ACPP and TOD regulatory assets, which is
16 included in Customer Service O&M expense supported by Witness Hatsios.

17

18 **Q164. What is the Pension Capitalized on line 54?**

19 A164. As previously described regarding pension expense, this balance represents the
20 capitalized non-service cost components of pension expense. Because the non-
21 service costs became negative, the deferred balance is projected to become a
22 regulatory liability during 2023 and is shown on line 110.

23

24 **Q165. What is the Demand Response Regulatory Asset on line 55?**

Line
No.

1 A165. Witness Farrell describes the Company's Demand Response programs and the
2 reconciliation process. The Commission's February 18, 2021 Order in Case No.
3 U-20793 approved a \$3.0 million regulatory asset for under recovered 2019
4 Demand Response costs, and recovery via inclusion of amortization expense in
5 base rates. The Commission also issued an Order on February 10, 2022 approving
6 a settlement in the DR 2020 Reconciliation, Case No. U-21044, reflecting an under
7 recovery of \$1.4 million and \$202,000 of incentives. The balance also reflects a
8 settlement in the DR 2021 Reconciliation, Case No. U-21242, of \$4.3 million,
9 approved by Order on January 19, 2023. The \$1.8 million balance on December
10 31, 2025 reflects \$8.9 million of deferrals in 2021 through 2023 offset by
11 accumulated amortization of \$7.1 million.

12

13 **Q166. What is the Incentive Compensation Regulatory Asset on line 56?**

14 A166. In Case No. U-20836, the Commission approved recovery of \$12.7 million for
15 incentive compensation related to operating metrics. The approved base amount
16 assumed the Company achieved 60% of its targeted metrics. The Commission's
17 Order also provided for deferral treatment above or below the base amount, up to a
18 maximum 100% target level, to be refunded or recovered in DTE Electric's next
19 rate case. In Case No. U-21297, the Commission reduced the approved base amount
20 to \$10.1 million assuming the Company achieves approximately 52% of its targeted
21 metrics. The projected balance assumes that DTE Electric will not achieve 100%
22 of its target levels in 2023 based on projected performance. The amount below base
23 will be deferred to a regulatory liability. However, the Company expects to achieve
24 100% of its target levels in 2024 and will defer the difference between the actual
25 results and the annual base amount of \$10.1 million. Please refer to Exhibit A-13,

Line
No.

1 Schedule C5.10.1. Line 4 shows the amounts to be deferred by calendar year. The
2 calculation assumes the full amount of incentive expense will be approved for
3 recovery starting with the projected test period (January 1, 2025 to December 31,
4 2025) with no deferral required.

5

6 **Q167. Do you recommend that the incentive compensation deferral mechanism be**
7 **continued?**

8 A167. If the Commission approves the Company's forecasted incentive compensation
9 costs for the projected test period, the mechanism is unnecessary. However, if a
10 lesser amount is approved, I request the deferral be continued, but with some
11 modifications.

12

13 **Q168. What modifications to the incentive compensation mechanism are you**
14 **proposing?**

15 A168. I propose three modifications. First, the base amount should be reset equal to the
16 amount of incentive compensation approved for recovery in base rates in this case.
17 Second, the mechanism should apply to the totality of the Company's incentive
18 compensation program including the portion related to financial metrics. Witness
19 FixCooper supports the reasonableness and prudence of the Company's
20 compensation practices, including incentives tied to financial metrics. Third, the
21 deferral should cover the total actual payout, including amounts above 100% of the
22 target. As described in more detail by Witness FixCooper, the incentive program
23 allows for a range of payouts from zero to 200% of target. The incentive plan is
24 designed to motivate employees to achieve results beyond the target, further

Line
No.

1 improving organizational performance and benefitting customers. Since the
2 Company must provide a refund to customers if results fall below the baseline, it is
3 reasonable to include the cost of achieving exceptional results.

4

5 **Q169. What is the Low-Income Assistance Tracker on line 57?**

6 A169. In Case No. U-20561, the Commission authorized DTE Electric to defer Residential
7 Income Assistance (RIA) and Low-Income Energy Assistance credits above a base
8 amount. The balance reflects that in 2022, the Company issued more LIA credits
9 to customers than were reflected in the base. In Case No. U-20836, the Commission
10 ordered any unspent RIA and LIA be recorded as a regulatory liability. Effective
11 with the Order in U-20836, any underspent amounts will be netted against any
12 regulatory assets recorded for overspent amounts. The projected balances were
13 based on a 13-month historical average.

14

15 **Q170. What is the Low-Income Payment Stability Plan regulatory asset on line 58?**

16 A170. In Case No. U-20929, the Commission authorized DTE Electric to defer costs
17 associated with its low-income customer assistance pilot (the Payment Stability
18 Plan or “PSP”). The PSP pilot creates a fixed maximum bill for participating
19 customers based on their income, rather than providing a fixed credit amount on a
20 variable bill like those provided by the residential income assistance or low-income
21 assistance programs. The balance consists of supplemental payments, arrears
22 forgiveness, benefit awards, and certain O&M implementation costs associated
23 with the pilot.

24

25 **Q171. What is causing the increase in Prepaid OPEB on line 62?**

Line
No.

1 A171. The Prepaid Post-Retirement Benefit asset increases from \$129.1 million on
2 December 2022 to \$194.3 million by December 2025. The year-to-year changes
3 are primarily the result of negative OPEB expense as explained by Witness
4 €Hooper.

5
6 **Q172. Can you explain the tax items on lines 59, 65 and 66 of Exhibit A-12, Schedule**
7 **B4.2?**

8 A172. Witness Wisniewski supports these tax-related assets. Line 59 represents the
9 excess deferred taxes that were remeasured related to reduction of the federal
10 corporate income tax rate change resulting from the 2017 Tax Cuts and Jobs Act
11 (TCJA). Line 65, Miscellaneous Tax Related, represents regulatory assets resulting
12 from changes in tax law such as Medicare Part D and the Michigan Corporate
13 Income Tax, reduced each year by amortization of approximately \$22.2 million.
14 Line 66, Recoverable Income Taxes, reflects a regulatory asset recorded in
15 conjunction with an offsetting ADFIT liability when ASC 740 (formerly FAS 109)
16 was adopted in 1993. It has scheduled reductions of \$2.4 million per year supported
17 by Witness Wisniewski. The ASC 740 balance sheet accounts do not affect the
18 revenue requirement. This accounting and rate treatment were approved by the
19 Commission in Case No. U-10083.

20
21 **Q173. How was Other Deferred Debits on line 68 of Exhibit A-12, Schedule B4.2**
22 **developed?**

23 A173. The Other Deferred Debits balance consists of pre-paid software, refundable spent
24 nuclear fuel storage costs, and short-term credit facility costs which were held
25 constant at the 13-month historical period. It also includes a pre-paid long-term

Line
No.

1 maintenance service agreement (LTSA) for the Blue Water Energy Center.
2 Changes in the LTSA balance reflect payments to the service provider, reduced by
3 transfers to capital and O&M as the services are rendered.
4

5 **Q174. What components make up the Liabilities and Other Credits reflected in**
6 **Exhibit A-12, Schedule B4.2, page 2 of 2?**

7 A174. Exhibit A-12, Schedule B4.2, page 2 of 2 has four major components:

- 8 1) Capitalization
- 9 2) Non-Current Liabilities
- 10 3) Current Liabilities
- 11 4) Deferred Credits

12

13 **Capitalization**

14 **Q175. How were the projected capitalization amounts determined in this case?**

15 A175. Capitalization (lines 73 through 83) reflects DTE Electric's permanent capital in
16 the form of long-term debt and common equity. Key long-term debt drivers
17 include new capital requirements, scheduled debt retirements, refinancing, level of
18 equity, and the amount of short-term debt. As previously discussed, the regulatory
19 liability related to the REP is a source of short-term debt. Schedule B4.2, line 76,
20 shows that long-term debt balances will increase during the forecast periods to
21 support DTE Electric's increasing asset base, as supported by Company Witness
22 Lepczyk.

23

24 Common equity balances on line 82 will also increase to finance the growing asset
25 base and to meet targeted capitalization percentages. Since projected earnings are

Line
No.

1 insufficient to meet the targeted equity capital percentages, common equity will
2 need to be funded from additional equity infusions as discussed and supported by
3 Witness Lepczyk. Projected common equity also reflects dividends required to
4 sustain and attract equity investors.

5 **Q176. What is the projected change in Capitalization?**

6 A176. Exhibit A-12, Schedule B4.2, line 76, reflects a long-term debt increase from
7 January 2023 to December 2024 of \$1,014.2 million primarily due to \$1,875.0
8 million of new debt issues, less redemptions of \$861.0 million. The \$144.3 million
9 long-term debt increase from January 2025 to December 2025 is primarily due to
10 new debt of \$1,300.0 million, less \$1,156.9 million of debt redemptions. Line 79
11 reflects Common Stock increases of approximately \$2.2 billion through December
12 2025 due to planned equity infusions as addressed by Witness Lepczyk, offset by
13 the removal of \$806.9 million of equity supporting the Monroe regulatory asset. A
14 portion of the Common Stock increases may be reduced from additional equity
15 based on the Commission Order in this case granting the rate relief requested.
16 Retained Earnings (line 80) decreases by \$62.6 million from January 2023 to
17 December 2024, resulting from net income of \$1,416.8 million, less common
18 dividend payments of \$1,479.4 million. Retained Earnings decreases from January
19 2025 to December 2025 by \$157.5 million resulting from twelve months ending
20 December 2025 net income of \$690.0 million less common dividend payments of
21 \$847.5 million. The changes in common equity are reconciled on Exhibit A-12,
22 Schedule B4.3.

23

Line
No.

1 **Non-Current Liabilities**

2 **Q177. What is included in Non-Current Liabilities on lines 85 through 91 of Exhibit**
3 **A-12, Schedule B4.2?**

4 A177. This section includes the liability for capital leases and injuries and damages.
5 Capital leases on line 85 is being held constant and represents the long-term portion
6 of the liability to offset the Net Capital Lease Property on line 10. The accumulated
7 provision for injuries and damages on line 87 is being held constant to the 13-month
8 historical average during the forecast period as new claims and settlements cannot
9 be predicted.

10

11 **Current Liabilities**

12 **Q178. What is included in Current Liabilities on lines 94 through 103 of Exhibit A-**
13 **12, Schedule B4.2?**

14 A178. This section includes short-term debt and payables. DTE Electric's short-term debt
15 balances on line 94 include the balances available from the REP regulatory liability.
16 The REP regulatory liability represents the temporary over-collection of DTE
17 Electric's REP surcharge. This liability is used by DTE Electric as an additional
18 source of financing in base rates. Interest on this liability is paid to our customers
19 via a credit in the Renewables Plan, lowering the revenue requirement for that
20 program.

21

22 **Q179. How did you forecast the balance for Accounts Payable on lines 96 and 97?**

23 A179. Accounts payable was forecasted based on a 13-month historical average as of
24 December 31, 2022.

25

Line
No.

1 **Q180. How did you forecast the remaining current liabilities?**

2 A180. Taxes Payable on line 98 reflects the timing of accruals and payments, as supported
3 by Witness Wisniewski. The changes in Interest Payable on line 99 also reflect the
4 timing of accruals and payments. Capital Leases Current on line 100 reflects the
5 current portion of the liability to offset the Net Capital Lease Property on line 10.
6 The fluctuations in line 102, Fermi 2 Outage accrual, result from forecasted
7 accruals and expenditures for the Fermi 2 planned outages supported by Witness
8 Davis on line 102. Other Current Liabilities on line 103 include vacation and
9 payroll accruals, customer deposits, and refundable contributions in aid of
10 construction, and are held constant at the historical 13-month average balance.

11

12 **Deferred Credits**

13 **Q181. What is included in Deferred Credits on lines 106 through 116 of Exhibit A-**
14 **12, Schedule B4.2?**

15 A181. The December 2022 balance related to line 106 Regulatory Liability - Renewable
16 Energy Program, was re-classified to short-term debt on my historical Exhibit A-2,
17 Schedule B6.2. Other Deferred Credits on line 116 includes refundable customer
18 advances, environmental reserves, and other accrued liabilities held constant at 13-
19 month average historic levels.

20

21 **Q182. What is the Regulatory Liability – OPEB on line 108?**

22 A182. The OPEB liability was established pursuant to the Commission's Order in Case
23 No. U-17767. Consistent with the treatment of pension expense, negative OPEB
24 expense, less amounts capitalized and transferred, are offset by a regulatory
25 liability. In Case No. U-21297, the Commission ordered that the Company must

Line
No.

1 amortize the OPEB regulatory liability of \$128.4 million as of the historical test
2 year (December 2022) over a seven-year period. The projected balance includes
3 additional deferrals due to projected negative OPEB expense offset by annual
4 amortization of \$18.3 million.

5

6 **Q183. What is the OPEB Capitalized on line 109?**

7 A183. As previously described regarding OPEB expense, this balance represents the
8 capitalized non-service cost components of OPEB expense.

9

10 **Q184. What is the Pension Capitalized on line 110?**

11 A184. As previously described regarding the pension capitalized asset, the non-service
12 costs became negative, and the balance is projected to become a regulatory liability
13 during 2023.

14

15 **Q185. What are the tax items on lines 113 through 115?**

16 A185. Witness Wisniewski supports lines 113 through 115. Accumulated Deferred
17 Income Taxes represents timing differences in the recognition of tax expenses for
18 the financial statements compared to the tax return. Both the federal and state
19 deferred tax balances reflect the netting of Deferred Tax Assets (Account 190)
20 against Deferred Tax Liabilities (Accounts 281, 282, and 283), consistent with the
21 presentation in the cost of capital calculation.

22

23 Deferred taxes on line 113 includes the outstanding tax liability balance to account
24 for tax benefits previously flowed through to ratepayers stemming from the 1993
25 enactment of ASC 740 as previously discussed. It is offset by the Regulatory Asset

Line
No.

1 (Recoverable Income Taxes) shown on Schedule B4.2, line 66. This accounting
2 and rate treatment were approved by the Commission in Case No. U-10083.

3

4 Accumulated Deferred Investment Tax Credits on line 114, supported by Witness
5 Wisniewski, are deferred tax credits generated and utilized by the Company with
6 the tax benefits flowing back to customers on the same basis as customers pay for
7 the assets that generated these tax credits.

8

9 The Tax Reform Regulatory Liability on line 115 results from the Tax Cuts and
10 Jobs Act of 2017, which among other things, lowered the corporate Federal tax rate
11 from 35% to 21%. The reduction in the tax rate required that all existing deferred
12 tax balances be re-measured using the 21% rate. The reduction in deferred taxes
13 was recorded to a regulatory liability to be refunded, generally, over the life of the
14 items causing the deferred tax, primarily plant. However, it also reflects accelerated
15 amortization of the liability per the Commission's April 8, 2021 Order in Case No.
16 U-20835. Witness Wisniewski explains the calculation of the regulatory liability
17 and the Company's refund schedule.

18

19 **MERC Closure Impacts**

20 **Q186. What impact does the anticipated closure of MERC have on the projections in**
21 **this case?**

22 A186. None. As described by Witness Milo, MERC will continue to operate until
23 generation using coal is discontinued at the Belle River Power Plant in mid-2026,
24 beyond the projected test period. Witness Milo supports the O&M and capital
25 expenditures required to safely operate MERC until it ceases operations.

Line
No.

1

2 **Q187. How does the Company plan to address the recovery of the plant assets**
3 **remaining after MERC ceases operations?**

4 A187. The Company proposes to include the remaining net book value of MERC's assets
5 in the securitization transaction for the Belle River coal assets. Securitization of
6 the coal handling assets for Belle River was approved in the Company's IRP Case
7 No. U-21193 by Commission Order issued on July 26, 2023. The Company
8 estimates that the net book value will be in the range of \$20 million.

9

10 **IRM Impacts**

11 **Q188. How does the Infrastructure Recovery Mechanism impact the projected**
12 **financials?**

13 A188. An overview of the mechanism is provided by Company Witness Foley. The
14 Commission Order in Case No. U-21297 approved an IRM for December 2023
15 through December 2025. The IRM capital expenditures and plant balances, the
16 related costs and revenues, and the related debt and equity are excluded from my
17 projected financial statements. This exclusion ensures that the revenue requirement
18 for the IRM is separate and distinct from the revenue requirement for base rates.
19 Company Witness Foley describes and supports the Company's proposal to extend
20 the IRM through 2027.

21

22 **Q189. Will the IRM expenditures be permanently excluded from base?**

23 A189. No. IRM investments will be transferred into the Company's overall rate base after
24 the investments have been made and put into service. The Company will reflect

Line
No.

1 this in the first general rate case after the investments have been reviewed through
2 an IRM reconciliation proceeding consistent with the Commission's Order in Case
3 No. U-21297. Until transferred to the Company's overall rate base rates, IRM
4 investments will be recovered through the IRM surcharge. Once the Commission
5 approves the transfer of assets from the IRM mechanism to the Company's overall
6 rate base, these assets be removed from the IRM surcharge.

7

8 **Q190. Is the Company proposing to reduce its future recovery by the amount of plant**
9 **that is being retired in this IRM program?**

10 A190. No. When plant is retired, the original recorded cost of the plant is both credited to
11 the plant in service accounts and charged to accumulated depreciation reserve; thus,
12 there is no change in the net plant balance related to the retirement. With no change
13 in net plant, there is no adjustment to the largest portion of the return-on-investment
14 portion of the revenue requirement calculation. As depreciation rates are
15 periodically adjusted in subsequent depreciation cases, the impact of any abnormal
16 retirements will be incorporated.

17

18 **Q191. What is the impact to customers if the IRM is approved but the Company does**
19 **not spend the full amount of projected capital expenditures?**

20 A191. As explained by Witness Foley, the Company will record a regulatory liability for
21 any over-recovery related to the IRM. The recording of any Regulatory Liability
22 will be reviewed through an IRM reconciliation proceeding, consistent with the
23 Commission's Order in Case No. U-21297. The Company will use account 254,
24 Other Regulatory Liabilities, for that purpose.

Line
No.

1

2 **Other Accounting Requests**

3 **Q192. What accounting treatment are you proposing for customer bill credits?**

4 A192. As discussed in detail by Witness ~~Foley Crozier~~, the Company is proposing that bill
5 credits related to outages beyond the Company's control be deferred for future
6 recovery. Consistent with the proposal in Case No. U-20836, the Company will
7 use account 182.3, Other Regulatory Assets, for that purpose. The Company
8 proposes to amortize the deferred amounts concurrent with their recovery in base
9 rates.

10

11 **Q193. What accounting treatment are you proposing for storm costs?**

12 A193. As described by Witness Foley, the Company is requesting a storm restoration cost
13 sharing mechanism. I am requesting the use of account 182.3, Other Regulatory
14 Assets, and 254, Other Regulatory Liabilities, to record the refundable or
15 recoverable portion of any difference between actual storm costs and the base
16 amount approved in this case.

17

18 **Summary**

19 **Q194. Can you summarize what Commission approvals the Company is requesting?**

20 A194. In addition to the forecasted costs and revenues included herein, the Company is
21 requesting a continuation of the previously approved deferral treatment for Pension
22 expense, OPEB expense, LIA/RIA credits, TOD implementation costs, PERC
23 projects, and certain Charging Forward programs. I am also requesting approval to

Line
No.

- 1 use accounts 182.3 and 254 to record any under/over recovery from the storm cost
- 2 sharing mechanism.
- 3
- 4 **Q195. Does this complete your direct testimony?**
- 5 A195. 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

EXHIBITS

OF

THERESA M. UZENSKI

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-21534

QUALIFICATIONS

AND

REVISED DIRECT TESTIMONY

OF

SHANNEN M. HARTWICK

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

Line
No.

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

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

5

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

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

8

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

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

13

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

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

24

Line
No.

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

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

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

17

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

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

21

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

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

Line
No.

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

3

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

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

Line
No.

1 **Purpose of Testimony**

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

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

8

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

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

12

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

Line
No.

1 A-19 I1.1 Telecom Reliability

2 A-19 I1.2 Telecom Cost

3

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

5 A10. Yes, they were.

6

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

8 A11. My testimony consists of the following parts:

9 Part I – Infrastructure Recovery Mechanism (IRM) Support

10 Part II – Grid Automation

11 A. Distribution Automation

12 B. Grid Automation Telecommunications

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

15 D. Non-Wire Alternative (NWA) Pilots

16 E. Grid Edge Insights and New Technology

17 F. Distribution Line Sensors

18 Part III – Operational Technology

19 G. Grid Management

20 H. Distribution Planning

21 I. Work Management and Scheduling

22 J. Asset Management

23 K. Mobile Technology

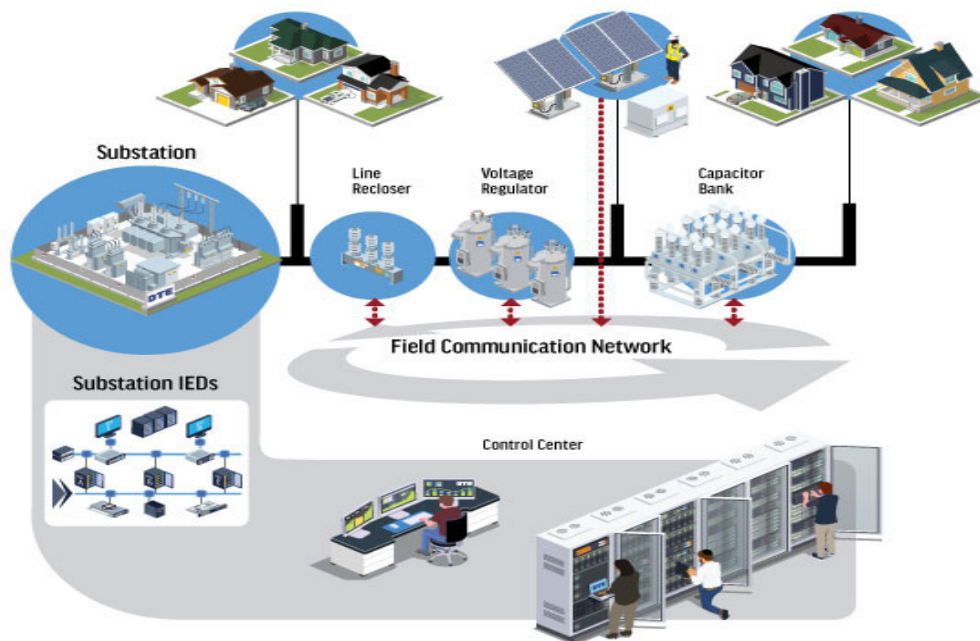
24

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

Line
No.

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

Figure 1 Modern Distribution Overview



Line
No.

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

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

10

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

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

16

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

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

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

Line
No.

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

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

10

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

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

17

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

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

Line
No.

1 **Grid Automation**

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

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

8

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

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

Line
No.

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

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

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

4 Exhibit A-23, Schedule M7

5

6 **Table 1 Grid Automation Exhibit Locations**

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

7

Line
No.

1 **A. Distribution Automation**

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

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

11

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

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

19

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

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

Line
No.

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

12

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

17

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

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

² See footnote 1.

Line
No.

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

11

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

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

Line
No.

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

3

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

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

Line
No.

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

5

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

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

23

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

Line
No.

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

16

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

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

Line
No.

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

6

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

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

15

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

21

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

Line
No.

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

3

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

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

20

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

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

Line
No.

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

13

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

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

24

Line
No.

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

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

11

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

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

22

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

Line
No.

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

13

14 **B. Grid Automation Telecommunications**

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

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

Line
No.

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

6

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

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

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

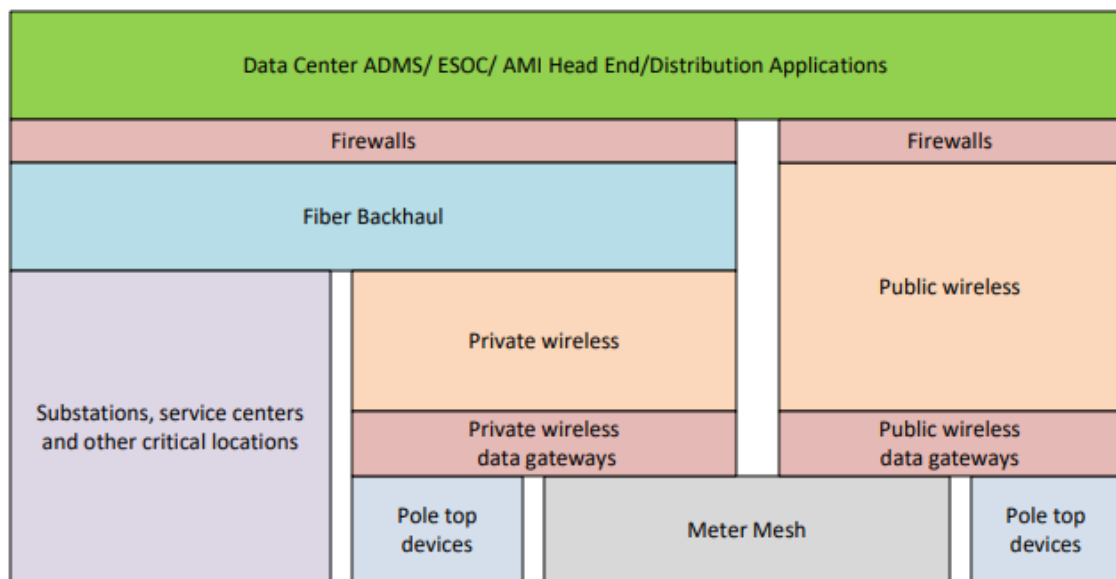
Line
No.

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

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

11

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



13

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

Line
No.

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

23

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

Line
No.

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

Line
No.

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

3

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

13

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

19

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

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

Line
No.

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

3

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

14

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

Line
No.

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

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

10

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

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

24

Line
No.

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

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

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

Line
No.

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

3

4 **Public cellular:**

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

8

9 **Current utilization:**

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

12 **Key Considerations:**

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

Line
No.

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

Line
No.

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

Line
No.

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

5

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

7 **Description:**

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

9 **Current utilization:**

- 10 • Not currently in use by the Company

11 **Key Considerations:**

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

16

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

18 **Current utilization:**

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

21 **Key Considerations:**

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

Line
No.

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

Line
No.

1 **Wireless mesh:**

2 **Description:**

- 3 • Utility owned radio equipment

4 **Current or optional utilization:**

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

9 **Key Considerations:**

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

15

16 **Leased fiber:**

17 **Description:**

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

19 **Current utilization:**

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

22 **Key Considerations:**

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

Line
No.

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

16

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

18 **Description:**

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

20 **Current utilization:**

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

23 **Key Considerations:**

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

Line
No.

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

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

11

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

17

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

Line
No.

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

9

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

Line
No.

1

Figure 3 Alternatives Compared Using Reliability Factors

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

2

Line
No.

1

Figure 4 Alternatives Compared Using Life Cycle Factors

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

2

3

Figure 5 Alternatives Compared Using Initial Cost Factors

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

4

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

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

Line
No.

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

17

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

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

Line
No.

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

18

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

21 A47. Highlights of 2022 installations include:

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

Line
No.

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

8 **2023 installations included:**

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

19

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

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

Line
No.

1 **2024:**

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

11 **2025:**

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

Line
No.

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

Line
No.

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

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

13

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

16

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

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

Line
No.

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

6

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

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

22

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

Line
No.

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

12

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

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

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

19

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

24

Line
No.

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

7

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

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

19

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

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

Line
No.

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

7

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

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

13

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

25

Line
No.

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

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

16

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

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

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

25

Line
No.

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

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

13

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

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

19

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

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

Line
No.

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

3

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

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

12

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

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

Line
No.

1

Table 2 NWA Pilots Use Cases, Technologies, and Objectives

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

2
3

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

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

13

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

Line
No.

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

4
5 **O'Shea**

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

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

13
14 **Q67. What progress has been made for the O'Shea Pilot?**

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

25

Line
No.

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

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

8

9 **Mobile Battery Trailer**

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

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

23

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

Line
No.

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

9

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

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

23

24 **Omega**

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

Line
No.

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

10

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

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

18

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

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

Line
No.

1 **Fisher**

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

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

17

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

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

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

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

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

Line
No.

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

4

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

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

9

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

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

13

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

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

Line
No.

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

3

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

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

10

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

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

16

17 **Port Austin**

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

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

Line
No.

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

6

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

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

13

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

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

21

22 **Veridian**

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

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

Line
No.

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

11

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

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

21

22 **EV Charging Demonstration at ACM**

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

Line
No.

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

14

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

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

17

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

28

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

Line
No.

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

6

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

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

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

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

19

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

Line
No.

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

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

21

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

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

Line
No.

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

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

22

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

Line
No.

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

5
6 **Q94. Can you describe the specific work for the NWA: EV Charging Demonstration**
7 **at ACM?**

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

Line
No.

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

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

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

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

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

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

Line
No.

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

4

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

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

Line
No.

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

3

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

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

20

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

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

Line
No.

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

12

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

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

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

Line
No.

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

10

11 **Adaptive Networked Microgrids**

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

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

21

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

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

Line
No.

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

11

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

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

20

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

Line
No.

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

5

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

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

14

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

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

23

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

Line
No.

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

10

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

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

19

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

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

24

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

Line
No.

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

6

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

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

15

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

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

21

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

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

Line
No.

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

3

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

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

10

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

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

21

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

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

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

Line
No.

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

Line
No.1 **Table 4 Key Investment Highlights for Grid Edge Insights and New Technology**

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

2

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

Line
No.

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

20

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

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

Line
No.

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

15

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

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

Line
No.

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

7

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

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

25

Line
No.

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

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

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

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

25

Line
No.

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

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

10

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

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

Line
No.

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

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

14

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

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

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

20

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

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

Line
No.

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

6

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

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

22

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

Line
No.

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

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

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

10

11 **Operational Technology**

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

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

18

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

Line
No.

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

4

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

9

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

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

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

Line
No.

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

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

Line
No.

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

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

10

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

14 A129. Yes. Other differences to consider include:

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

Line
No.

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

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

18

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

22

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

Line
No.

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

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

12

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

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

19

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

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

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

Line
No.

- 1 • Mobile Technology

2

3 **G. Grid Management**

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

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

16

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

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

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

Line
No.

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

7

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

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

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

Line
No.

1

Table 5 Grid Management Exhibit Locations

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

2

3 **System Operations Center (SOC) and Alternative System Operations Center**

4 **(ASOC) Projects**

5 **Q136. What is the SOC Modernization Project?**

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

Line
No.

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

4

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

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

16

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

Line
No.

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

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

12

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

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

16

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

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

23

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

Line
No.

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

5

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

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

17

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

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

22

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

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

Line
No.

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

3

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

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

19

20 **Advanced Distribution Management System (ADMS) Distribution Management**
21 **System (DMS)/Outage Management System (OMS)**

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

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

Line
No.

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

10

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

19

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

25

Line
No.

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

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

8

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

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

20

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

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

Line
No.

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

9

10 **Other Modernize Grid Management**

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

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

18

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

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

Line
No.

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

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

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

11

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

13 A151. The key investments in this category are:

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

21

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

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

Line
No.

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

4

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

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

12

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

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

14

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

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

21

Line
No.1 **Table 7 Other Modernize Grid Management by Year (\$000)**

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

2

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

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

8

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

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

18

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

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

Line
No.

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

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

5

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

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

14

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

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

22

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

Line
No.

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

4
5 **Q162. What is the key driver of the CT/VT High Voltage Test Console project?**

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

9
10 **Q163. What are the benefits of the CT/VT High Voltage Test Console project?**

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

18
19 **Q164. Why is it important to undertake this project now?**

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

22
23 **Q165. What are the pre-storm season and post-storm season ADMS Enhancements?**

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

Line
No.

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

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

14

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

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

24

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

Line
No.

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

6

7 The scope of work completed is detailed below:

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

Line
No.

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

Line
No.

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

3

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

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

15

16 **ADMS Enhancement**

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

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

Line
No.

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

4

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

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

12

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

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

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

Line
No.

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

Line
No.

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

3

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

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

11

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

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

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

21

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

Line
No.

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

3

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

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

8

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

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

10

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

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

15

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

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

Line
No.

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

6

7 The Outage Status App Updates and Security Upgrades project developed a revised
8 security framework for authorizing access to non-badged contractor crews through
9 the Outage Status app. Prior to this project, contractor crews were required to be
10 badged to have access to the Outage Status app, which is a tool utilized to perform
11 their job duties. Being a badged contractor also allowed the contractor crews access
12 to other Company information. The Company identified the need to restrict certain
13 contract workers to updating the Outage Status app exclusively, therefore removing
14 their access to other Company information. This required a new security
15 configuration to allow non-badged contract crews access to the Outage Status app.

16

17 The Pentos PPE Dashboard project included the development of an employee tile
18 in SAP to centralize and provide access to Personal Protective Equipment (PPE)
19 information for Supply Chain, the Glove Lab, Supervision, and front-line
20 employees. This dashboard was integrated into SAP Success Factors Tile for a
21 unified platform managing all employees' equipment. Additionally, the project also
22 included the implementation of self-service equipment ordering (e.g., PPE, rubber
23 gloves, sleeves, calibration equipment) for both employees and admins.

24

Line
No.

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

3

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

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

14

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

25

Line
No.

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

9
10 The DO RCO Enhancement GPS Productivity project is focused on upgrading the
11 current GPS dashboard to address issues such as data errors, manual refreshing, and
12 the need for real-time reporting. By leveraging modern technology and cloud-based
13 platforms, the project aims to reduce manual tasks and provide same-day, real-time
14 metrics. These metrics include vehicle time to leave, time to the first job, and time
15 returned to the service center. The goal of the refreshed dashboard is to eliminate
16 gaps in data, offering a comprehensive view of service center time metrics on the
17 same day.

18
19 Within the OT investment is the SOS Hardening project. This project is focused
20 on implementing enhancements to strengthen the resilience of the ADMS System
21 Outage Screen (SOS) and its related capabilities, which includes the ongoing
22 migration of crucial Azure infrastructure that supports SOS reporting and
23 notifications within DTE's Azure environment. In addition, support is being
24 provided for integrating the SOS application with the Outage Status Application
25 (OSA) to enhance the client's Damage Assessment capabilities. The SOS

Line
No.

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

6

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

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

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

17

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

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

Line
No.

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

8

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

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

17

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

23

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

Line
No.

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

8
9 Fundamentally, this project will enhance the existing AMI Network by identifying
10 locations that lack the capacity to transport the volume of data needed from meters
11 to the OMS system and adding additional network communication devices to those
12 locations. These additions will be added in a structured manner based upon the
13 number of customers served, reliability of the electric grid in that area, and
14 reliability of AMI network in that area. Additional considerations, such as the
15 communities served by that network segment, will be taken into account to ensure
16 the Company effectively supports its most vulnerable customers.

17
18 This project will focus on maximizing the:

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

24

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

Line
No.

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

Line
No.

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

7

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

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

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

Line
No.

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

Line
No.

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

6

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

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

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

18

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

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

Line
No.

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

3

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

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

10

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

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

19

20 **Microwave End of Life**

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

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

Line
No.

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

3

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

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

8

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

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

16

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

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

22

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

Line
No.

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

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

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

15

16 **FLISR Implementation**

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

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

Line
No.

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

18

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

20 A191. This investment provides fundamental support to DTEE's initiative to improve
21 overall outage restoration and storm restoration commitments, and the Company
22 agrees with the Commission's statement in Case No. U-21297 that, "outage
23 restoration is a critical area" (U-21297, pg. 114). The continued investment in
24 FLISR will help the Company improve storm restoration via reduced outage
25 duration, as well as enable the Company to continue realizing the full benefits of

Line
No.

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

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

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

20

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

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

Line
No.

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

3

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

14

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

22

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

Line
No.

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

3

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

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

8

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

20

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

Line
No.

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

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

17

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

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

Line
No.

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

8

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

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

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

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

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

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

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

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

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

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

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

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

21 other distributed technologies.

22

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

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

Line
No.

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

Line
No.

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

4

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

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

16

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

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

Line
No.

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

6

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

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

23

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

Line
No.

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

11

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

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

25

Line
No.

1 **Substation Cybersecurity Program**

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

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

12

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

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

Line
No.

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

5

6 **Automation Configuration Database**

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

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

25

Line
No.

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

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

8

9 **H. Distribution Planning**

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

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

Line
No.

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

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

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

7

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

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

9

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

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

Line
No.

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

12

13 **Network Management System (NMS)**

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

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

25

Line
No.

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

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

13

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

16

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

25

Line
No.

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

6
7 **3. Grid Model Analytics:** Centers on using analytics to gain insight into behavior,
8 performance, and characteristics of the grid. The objective is to improve reliability,
9 efficiency, and overall functionality of the electrical grid by leveraging data-driven
10 insights derived from the grid model.

11
12 **4. Asset Data Integration:** Consolidates data from different databases, sensors,
13 and sources to create a unified and comprehensive view of the assets. The goal is
14 to enhance data accuracy, accessibility, and usability, enabling better decision-
15 making and management in a coordinated manner.

16

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

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

23

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

Line
No.

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

11

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

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

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

Line
No.

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

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

17

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

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

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

Line
No.

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

10

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

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

17

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

21

22

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

Line
No.

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

3
4

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

9

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

14

15 **Load Forecasting & Analytics**

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

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

25

Line
No.

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

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

7

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

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

19

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

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

Line
No.

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

Line
No.

1 **Interconnection Process Enablement**

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

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

12

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

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

22

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

Line
No.

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

3

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

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

17

18 **Hosting Capacity Enablement**

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

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

23

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

Line
No.

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

5

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

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

15

16 **Power Quality Analysis Program**

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

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

25

Line
No.

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

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

3

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

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

12

13 **Substation Design Tool Upgrades**

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

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

21

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

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

Line
No.

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

4

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

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

14

15 **Distribution Planning**

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

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

20

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

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

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

Line
No.

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

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

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

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

15

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

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

Line
No.

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

9

10 **I. Work Management and Scheduling**

11 **Q236. What is Work Management and Scheduling?**

12 A236. Work Management is a systematic approach to track and measure work as well as
13 streamline both business processes and routine tasks. This category of investments
14 describes the essential set of work management tools and technologies that are used
15 to coordinate work on the distribution system, from initiation through close out of
16 work orders, including the work steps, assignment of labor, materials, and other
17 tasks. While current schedules and processes rely on Microsoft Excel, the benefits
18 of automation, like drag-and-drop schedules, real-time field status updates, and
19 integration with systems such as OMS and Maximo, are realized through these
20 investments. Job planning, along with managing labor, material, tools, and services,
21 is also part of the suite of tools for effective work management.

22

23 **Q237. Where are the capital investment details of the projects and programs in this**
24 **category?**

Line
No.

1 A237. Capital investment details of these projects and programs in this category are
2 included in:

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

5

6 **Table 10 Work Management and Scheduling Exhibit Locations**

Program/Project	Exhibit A-12 Sch. B5.4	Exhibit A-23 Schedule M7	Exhibit A-23 Schedule M8
Enhance Maximo Capabilities and Processes	p. 18, line 47	pp. 62-65	pp. 155-157
Primary Service Orders Replatform	p. 18, line 48	pp. 173-176	pp. 155-157
External Crew Efficiency	p. 17, line 23	pp. 66-69	pp. 155-157
Work Management and Scheduling Upgrades	p. 18, line 49	pp. 219-222	pp. 155-157
Substation Reporting and Process Enhancements	p. 17, line 20	pp. 203-206	pp. 155-157

7

8 **Enhance Maximo Capabilities and Processes**

9 **Q238. What is Enhance Maximo Capabilities and Processes?**

10 A238. Enhance Maximo Capabilities and Processes is a project aimed at improving and
11 expanding the functionality of Maximo, the Company's Work and Asset
12 Management system, and optimizing its associated processes.

13

14 **Q239. What are the key drivers of Enhance Maximo Capabilities and Processes?**

15 A239. DTEE's Work and Asset Management system, Maximo, has both on-premise and
16 field enabled capabilities. The field portion of that system is currently filled by a
17 field module, EZMax Mobile, that would have been replaced as part of the Maximo

Line
No.

1 transformation program that is under re-evaluation. With that program now on hold
2 the Company will invest in an upgrade of the EZMax mobile product in 2025 to
3 ensure that users retain the ability to work effectively at the point of activity using
4 an up-to-date product.

5

6 **Q240. What are the benefits of Enhance Maximo Capabilities and Processes?**

7 A240. This project will bring more of the capability of the existing Maximo system to the
8 front line in the form of additional inspection forms, inspection workflows and
9 expanded asset information. Bringing this capability to the field worker will
10 eliminate a portion of the remaining paper-based data collection as well as ensuring
11 that field teams have electronic access to the up-to-date equipment records when
12 performing work making that work safer and more efficient.

13

14 **Primary Service Orders Replatform**

15 **Q241. What is the Primary Service Orders (PSO) Replatform?**

16 A241. The Primary Services Group at DTEE is responsible for working with and assisting
17 many of the Company's largest commercial and industrial customers. To help them
18 perform their work, a web-enabled tracking system that houses primary customer
19 information is used. In addition to being an important tool for the Primary Services
20 Group, other departments such as Regional Relations, MAS, and the Relay Group
21 use this system when working with or for these customers.

22

23 The PSO Replatform project is a 3-year investment beginning in 2024 with a
24 targeted completion in 2026. The scope of the project has 4 major components:

- 25
- Upgrade existing end-of-life primary services web-enabled system.

Line
No.

- 1 • Capture and maintain detailed customer information and electronic primary
- 2 operating orders.
- 3 • Digitize and archive the primary customer infrastructure as-builts and sketches.
- 4 • Build interfaces between the new application and supporting systems, such as
- 5 customer relationship management, enterprise asset management and mapping
- 6 systems.
- 7

8 **Q242. What are the key drivers of PSO Replatform?**

9 A242. Today there are three separate systems required to fully support these functions.
10 The PSO Replatform project will combine all the existing systems into one
11 consolidated system and provide automated connections to other systems that today
12 are not connected. This new system, when fully implemented, will connect with
13 other customer facing systems such as the customer relationship management
14 (CRM), enterprise asset management (Maximo) and mapping systems (ESRI). The
15 current primary services application requires extensive manual processing and data
16 entry, resulting in productivity loss and an inability to keep up with increasing
17 demand. This negatively impacts the customer experience and level of service
18 DTEE can provide.

19

20 **Q243. What are the benefits of PSO Replatform?**

21 A243. The goal of this project is to create a single system that houses primary customer
22 information and equipment needed to isolate customers from DTE Electrical
23 system and vice versa. This system will provide support to field resources with
24 quick access to customer infrastructure and eventual connectivity to ESRI, Maximo
25 & CRM with up-to-date information needed to effectively support primary

Line
No.

1 customer needs. Customers will receive better and faster service and employees
2 will be able to effectively handle more requests faster.

3

4 **External Crew Efficiency**

5 **Q244. What is External Crew Efficiency?**

6 A244. External Crew Efficiency is a category of capital investments targeted at the
7 efficient and cost-effective use of external contract crews used to augment
8 Company crews. The capability to utilize external crews efficiently and cost-
9 effectively is a key component to improving the speed and efficiency of storm
10 restoration. The primary investment in this category is the Utility Restoration
11 Management Application (URMA).

12

13 **Q245. What is URMA?**

14 A245. URMA is an application that will manage crew rosters for external contract crews,
15 track current jobs status and work completed in the field, while enabling visibility
16 into contractor productivity and payment.

17

18 **Q246. What are the key drivers of the URMA application?**

19 A246. The Company relies heavily on external contract crews to support restoration
20 efforts when there is a significant event on the grid, especially during major weather
21 events. As the Company works to improve restoration for customers during storms
22 the command, control and logistics associated with the deployment of those crews
23 has never been more critical. Currently the Company lacks visibility into work
24 performed by non-DTE contract crews and cannot easily measure productivity for
25 these crews. Additionally, the rosters submitted for these crews are not

Line
No.

1 standardized, many being excel files that are submitted individually, making it
2 challenging to easily view and analyze rosters for all crews. In order to reduce
3 waste and improve productivity, ultimately leading to faster storm restoration, the
4 Company needs improved visibility and monitoring over these crews.

5

6 **Q247. What is the scope of the URMA application?**

7 A247. This is a multi-year project that began in June of 2023 with the first implementation
8 occurring in February of 2024. Delivered in that first implementation was an end-
9 to-end crew rostering application. The rostering application standardizes qualified
10 crew make up and the equipment used at the job site by external contract crews,
11 enabling operational control and the development of cost benchmarking to assist in
12 continuing to reduce overall cost per outage event.

13

14 The next set of investments for 2024 and 2025 are planned to include:

- 15 • Mobile application expansions that will status and ensure workflows for all
16 assigned work.
- 17 • A work completed input form that will document all material used, actual work
18 completed by teams in the field, give visibility on work mix, and validate
19 invoices from external contract crews.
- 20 • Expand rostering capabilities to Baseload contractors, Secure First, Single
21 Damage Assessors, and Damage Assessors to deploy these teams efficiently
22 and accurately.
- 23 • Expand the use of the electronic mobile work application to Baseload
24 contractors, Secure First, Single Damage Assessors, and Damage Assessors.

Line
No.

- 1 • Expand the use of the work completed input form to Baseload contractors,
- 2 Secure First, Single Damage Assessors, and Damage Assessor.
- 3 • Deliver a billing app to document contractor time entries, validate work
- 4 assignments, and expedite accurate invoicing.

5

6 Productivity improvements for outages include:

- 7 • Enhanced functionality in URMA will allow external contract crews to have
- 8 quick electronic access to job specific information (maps, assignments,
- 9 chronology), driving improvements on patrol and restoration times.
- 10 • Real time job status and updates on work required will allow the Emergency
- 11 Field Leaders and Regional Incident Command to take quick action to manage
- 12 crews more effectively.
- 13 • Clear line of sight into crew make-up and available equipment will inform
- 14 resource assignment and optimization.
- 15 • Right-crew to the right job: Contractor resources are currently not optimized
- 16 across restoration work type (i.e., too many contractors on smaller jobs or
- 17 spending too much time on the job). Using Single outage jobs as an example,
- 18 most jobs require only 2 crew members and should be completed in less than 2
- 19 hours.

20

21 **Q248. What are the benefits of the URMA application?**

22 A248. Currently, much of the coordination with external contract crews is manual process-

23 based and not system-enabled. This can lead to gaps in timely visibility into work

24 performed in the field, challenges with the ability to measure foreign and contractor

25 crew productivity, and overall control of those resources in real-time. These

Line
No.

1 challenges are further exacerbated during major storms. The benefits of URMA
2 include: reduction of waste through improved quality controls and crew validation;
3 improved ability to monitor and audit contractor invoicing to ensure accuracy; and
4 improved visibility of contract crew work scope and real time job statuses. The crew
5 rostering application supports the reduction of waste and improved auditing of
6 contractor invoicing by providing visibility, validation and verification of crew pay
7 rates, crew sizes, and equipment utilized per job. The improved visibility of
8 contract crew work scope and real time job statuses provides the Company
9 leadership increased oversight and ability to monitor performance and drive
10 productivity real time during storm restoration. Additionally, URMA provides
11 more efficient communication of contract crew work assignments directly to the
12 crews, reducing wait time for crews to receive work assignments, and allows
13 contract crews to access job specific information electronically, improving
14 restoration time. The Company has estimated these improvements will drive
15 efficiencies and productivity in storm restoration efforts, reducing the average
16 storm duration by three hours.

17

18 **Work Management and Scheduling Upgrades**

19 **Q249. What Work Management & Scheduling upgrade investments were made in**
20 **2022 and 2023?**

21 A249. Type 2 Customer Communication & Process Efficiency - (Closed Loop) - Phase 2,
22 Contract Agreement System (CAP) Replacement, Maximo Application Suite
23 Upgrade Phase 1 sponsored by Company Witness Sharma, Crew Management
24 Enhancements (2022/2023), multi-year renewal license purchase for ARCOS

Line
No.

1 operator call out application, PMO Primavera upgrade and field operations tools
2 automation are the investments made in 2022 and 2023.

3

4 **Q250. What is the Type 2 Customer Communication & Process Efficiency Closed**
5 **Loop project?**

6 A250. The Type 2 Customer Communication & Process Efficiency – Closed Loop project
7 included the development of a new application designed to track customer type 2
8 damage claim interactions, instances where customers file a claim that the
9 Company damaged their property while performing work. The new application
10 was initiated to improve claim management, communication with customers
11 regarding their claim, and reduce overall process cycle time for customers.

12

13 **Q251. What are the key drivers of Type 2 Customer Communication & Process**
14 **Efficiency?**

15 A251. The Damage Claims group historically utilized multiple systems, or tools such as
16 Excel, to manage damage claims and communicate updates to customers. These
17 systems were not integrated, nor did they provide visibility to all key stakeholders
18 and customers. The cycle time to resolve damage claims was on average 60-90
19 days, and there was no automated way to send customers standard updates
20 throughout the process and when claims were closed. Additionally, when customers
21 called into the DTEE call center, the call center representative did not have
22 visibility into a claim status and could not provide the customer information
23 regarding a claim. As a result, the Company received complaints from customers
24 about the damage claims process.

25

Line
No.

1 **Q252. What are the benefits of Type 2 Customer Communication & Process**
2 **Efficiency?**

3 A252. With the completion of this project claims are tracked and processed centrally
4 through the new application which includes all case information and is integrated
5 in the Company's customer relationship management system (CRM). This
6 includes a validation tool for customers to confirm their claims have been
7 submitted, a feedback loop for customers once claims have been resolved, and a
8 one stop repository for both active and resolved claims. This investment improved
9 the response time for damage claims resolution, with the average response time
10 dropping from an average of 60-90 days down to 23 days in 2023. Additionally,
11 this system is integrated with the Company's CRM, which allows customer service
12 representatives in the call center to see claim statuses and provide customers
13 updates as requested. This investment also enabled the Company to automatically
14 send weekly communications to customers regarding claim status updates and a
15 communication when a claim has been resolved through various methods such as
16 letters, texts and calls. In 2023, 100% of customers that filed a claim were
17 communicated to upon claim resolution.

18

19 **Q253. What is the Contract Agreement System (CAP) Replacement?**

20 A253. In 2022 the Company began a project to replace the existing Contract Agreement
21 System (CAP). That system was an internally created program which was no longer
22 meeting the needs of the business unit. The system did not have the capability to
23 easily create new agreement types and had no electronic document signing or
24 interchange mechanisms.

25

Line
No.

1 **Q254. What are the key drivers of CAP Replacement?**

2 A254. The Company enters into over \$3 million dollars a year in contracts for new
3 business and construction/service work. The current system is limited in the
4 information it provides and inefficient, it does not include automated workflow for
5 timing, nor does it have alerts to assist the contracts team in understanding when
6 any step in the process has taken longer than expected to complete. This can result
7 in extended construction service times and negatively impact customers that are
8 attempting to have services performed by the company on their behalf.

9

10 **Q255. What are the benefits of CAP Replacement?**

11 A255. This system helps the Company remain compliant with service levels related to
12 timing for new business and construction/service work for customers. In addition,
13 it provides the flexibility to create new types of agreements, allows more rapid
14 process improvements more easily than the previous system, and has improved
15 worksheet operability covering 15 electric service and construction agreements. For
16 customers, this translates into more efficient contract approval, a simplified
17 electronic routing processes for document management and leverages DOCUSIGN
18 for electronic signature to improve the customer experience.

19

20 **Q256. What is Crew Management Enhancement?**

21 A256. Crew Management Enhancement is a Crew Rostering system for DTEE crews that
22 replaced the outdated Crew Rostering system and will be integrated into the URMA
23 application as it goes into service. This is crucial for the Company's operational
24 groups to effectively build, manage, and deploy crews while adhering to union

Line
No.

1 agreements and maintaining DTEE's commitment to safe, timely, and qualified
2 service.

3

4 **Q257. What are the key drivers of Crew Management Enhancement?**

5 A257. DTEE employs processes and systems for resource management of internal DTEE
6 crews. The two-year project brought significant improvements, including
7 infrastructure updates, enhanced crew visibility, automated tracking of overtime
8 and training, adjustments for union contracts, and the integration of apprentice
9 rostering without manual intervention. Additional enhancements in 2024 and 2025
10 is part of the External crew efficiency project.

11

12 **Q258. What are the benefits of Crew Management Enhancement?**

13 A258. The capacity to efficiently roster and deploy crews ensures that work can be
14 accomplished with greater safety and speed.

15

16 In 2022, the system transitioned to new infrastructure, improving performance, and
17 features such as visible crew resources, automated overtime and training tracking,
18 and integration of vacation calendars were introduced. A visual dashboard
19 increased crew availability visibility, and record-keeping for employee OT
20 scheduling improved.

21

22 Continuing into 2023, continuous improvement led to additional enhancements, a
23 dedicated training environment, adaptability to changes in union contracts, Fleet
24 Organization integration for calendaring and OT reporting, and expanded
25 management-level reporting. The introduction of a training environment allowed

Line
No.

1 users to train on the rostering system beyond initial introductory training. With the
2 ability to effectively roster and deploy crews, work will be done more safely and
3 quickly.

4

5 **Q259. What is PMO P6 Primavera Refresh project?**

6 A259. PMO P6 Primavera Refresh project is an upgrade from the current unsupported
7 version of Primavera Scheduler used by DO Scheduling and DO PMO Groups to
8 the newest version of Primavera. In addition, the project includes the replacement
9 of the current WTA (Walter Tanner & Associates) interface between Primavera and
10 Maximo with an industry standard product called Maxavera.

11

12 **Q260. What are the key drivers of PMO P6 Primavera Refresh?**

13 A260. Primavera is the scheduling software used by DTEE's DO Scheduling and PMO
14 Groups to manage and execute the entire DO strategic capital investment. The
15 current version of Primavera used by DO Scheduling and PMO was 16 major
16 revisions behind and unsupported by the vendor. If the software were to crash, DO
17 Scheduling and PMO would lose the ability to manage the DO strategic capital
18 portfolio, affecting critical capital investments in the grid.

19

20 **Q261. What are the benefits of PMO P6 Primavera Refresh?**

21 A261. The upgraded Primavera version (and Maxavera interface product) will eliminate
22 data latency that is currently present with the Primavera and Maximo systems and
23 provide a more robust application. It will also bring the DO PMO group to the
24 same version of the scheduling product as the corporate project management office
25 is using allowing fee exchange and interoperability of schedules across all DTEE.

Line
No.

1 **Q262. What is the Multi-year Renewal license purchase for ARCOS?**

2 A262. DTEE has utilized the ARCOS Callout solution for several years, necessitating
3 frequent license renewals. Recently, the company successfully negotiated a
4 comprehensive 5-year agreement during the latest renewal, preventing year-over-
5 year cost increases and ensuring elevated warranty support throughout the period.

6
7 **Q263. What are the key drivers of Multi-year Renewal license for ARCOS?**

8 A263. The ARCOS license was expiring, and the Company was facing potential cost
9 increase for future licenses. This system is crucial for the Substations group to
10 conduct after-hours callouts while adhering to collective bargaining agreements
11 and union rules.

12
13 **Q264. What are the benefits of Multi-year Renewal license for ARCOS?**

14 A264. This investment ensures the continuity of an operational callout system,
15 maintaining efficiency and reliability in managing after-hours dispatching for the
16 substations group. By negotiating a 5-year agreement the company was able to
17 reduce future cost increases for licenses and obtain elevated warranty support.
18 The ARCOS system itself enables timely and accurate job callouts, reducing
19 response times for substations employees to respond emergent issues on the grid.

20
21 **Q265. What is Field Operations Tools Automation?**

22 A265. Field Operations Tools Automation is an investment undertaken to replace existing
23 operational tools, applications and dashboards that perform important operational
24 control functions but that no longer have the capability to support DTEE's rapidly
25 evolving operational processes. Some DO apps use extremely old technology and

Line
No.

1 utilize on-premises servers. These apps are built on 20-year-old foundations, such
2 as classic ASP and PHP, which substantially increases maintenance cost. The
3 objective is to automate manual efforts and reduce reliance on managing operations
4 through excel spreadsheets.

5
6 In 2023, a project to develop a system for use in confirming Customer Power Status,
7 particularly in-line with restoration efforts was in place. The project created a
8 facility to visualize the power status of meters at Customer sites along with the state
9 of the communications devices necessary to backhaul the data to DTE. This utility
10 gives insights to analysts tasked with determining why the current power state at a
11 customer site is unknown and facilitates detection of nested outages or field
12 communication devices that may need repair.

13

14 **Q266. What are the key drivers of Field Operations Tools Automation?**

15 A266. As the Company continues to work to improve its operations both in normal
16 weather conditions and during increasingly frequent weather events it continues to
17 rely upon both departmental applications and internally built solutions. Many of
18 these solutions do not scale and are not serving current or emerging needs
19 adequately. Several systems that measure day-to-day performance are dependent
20 on manual steps and do not have a consistent approach to data management. Report
21 generation is not consistent between groups/regions/service centers. This leads to
22 process inefficiencies and reduces situational awareness. The Field Operations
23 Tools Automation project was undertaken to begin to select the most important of
24 these use cases and automate them in an effective and supportable manner.

Line
No.

1 Increasing automation in these activities will increase visibility into process
2 adherence, help better identify gaps and improve situational awareness.

3

4 **Q267. What are the benefits of Field Operations Tools Automation?**

5 A267. For customers, this investment will result in tighter control of field events, more
6 information in the hands of crews to be shared with customers at their work
7 locations and improved response and restoration times during outage events.
8 Employees will be able to minimize usage of and reliance upon cumbersome
9 manual processes, add new opportunities to collaborate when reviewing/ sharing/
10 editing, and tracking activities. Instances of duplicative effort and human error will
11 be reduced. Team members can focus on value-add versus manual activities.

12

13 The 2023 efforts around CPS facilitated faster detection of on-going electric service
14 and communication network issues that can impact a customer's service restoration
15 and timely notifications. It was important to undertake the project in the time frame
16 it was executed to provide supporting insights to the larger Customer Power Status
17 Visualization (CPSV) program efforts designed to improve DTEE's outage
18 detection and service restoration efforts.

19

20 **Q268. What are the new investments planned for 2024 and 2025 in the Work**
21 **Management & Scheduling upgrade category?**

22 A268. The planned investments in the work Management & Scheduling upgrade category
23 for 2024 and 2025 are: Circuit ownership app, Wiredown Associated Call
24 Enhancement, and moving Mobile timesheet (MTS) Data to cloud.

25 • Circuit Ownership application:

Line
No.

1 The Circuit Ownership App is a new tool that consolidates data to a central location
2 for the Circuit Owner's comprehensive review. This data encompasses AMI Meter
3 Data, SCADA Data, Circuit Maps, current Maximo Work Orders in the field, and
4 Damage Assessment Information.

5 The new tool will facilitate a centralized contact accountable for real-time circuit
6 performance, strategizing, and advocating for the circuits. This strategy may
7 involve both short-term reliability projects (completed in under a year) and
8 extensive multi-year reliability projects.

9 The identified benefits include a streamlined process, reducing engineers' time
10 navigating various systems, resulting in quicker analysis and decision-making for
11 service-affecting issues on the circuits they oversee.

12

13 • Wiredown Associated Call Enhancement:

14 The company frequently receives redundant reports of wires down in the field,
15 resulting in the creation of multiple jobs in OMS. This causes delays and
16 unnecessary truck rolls.

17 The Wiredown Associated Call Enhancement investment involves updating the
18 OMS to efficiently link wiredown jobs, reducing wasted truck rolls and enhancing
19 productivity. The Field Service Edge application will be modified to display
20 associated calls on a job, enabling crews to access necessary data for safe evaluation
21 of wire down incidents and addressing public safety concerns. This enhancement
22 aims to streamline and enhance the efficiency of wiredown job responses.

23

24 • Moving mobile time sheet (MTS) data to Cloud:

Line
No.

1 Presently, the Company can observe general time sheet charges and manually delve
2 into specifics for OH/UG crews for an event requiring a truck roll.

3 The new cloud-based data will allow the OH/UG teams to automate reports on
4 detailed crew time charges, enhancing our understanding of defect codes like wait
5 time. Utilizing the cloud data platform will integrate disparate sources, such as
6 Mobile Timesheet charges and Outage Management events, enabling automated
7 reporting dashboards for timely field productivity visibility.

8 The implementation of this system can eliminate approximately 2 hours of daily
9 manual work for four individuals, equivalent to a full-time Operations Analyst
10 position worth \$80,000 per year. This will not completely offset the position, but
11 provides an opportunity for more productive and analytical tasks. Additionally, it
12 increases the capacity to run reports for all Service Centers, saving time and
13 identifying opportunities to enhance field productivity, both in storm and non-storm
14 scenarios.

15

16 **J. Asset Management**

17 **Q269. What is Asset Management?**

18 A269. Asset Management is a category of investments that involve utilizing technology
19 to support effective asset management. These investments include projects that
20 support managing physical assets, such as personal protective gear and large fleet
21 vehicles, as well as projects that support electronic asset data management.

22

23 **Q270. Where are the capital investment details of the projects and programs in this**
24 **category?**

Line
No.

1 A270. Capital investment details of these projects and programs in this category are
2 included in:

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

5

6 **Table 11 Asset Management Exhibit Locations**

Program/Project	Exhibit A-12 Sch. B5.4	Exhibit A-23 Schedule M7	Exhibit A-23 Schedule M8
Systematic Tracking of Rotatable Assets	p. 17, line 22	pp. 207-210	pp. 157-159
Asset Management Upgrades	p. 17, line 21	pp. 21-24	pp. 157-159

7

8 **Systematic Tracking of Rotatable Assets**

9 **Q271. What is the Systematic Tracking of Rotatable Assets?**

10 A271. This new investment in 2025 includes developing and implementing a digital
11 tracking repository for items like personal protective equipment that have
12 expiration dates and must be managed through their deployed life cycles. It
13 improves the accuracy, efficiency, and accountability on the movement of materials
14 within a process. Examples include Field tracking of assets using RFID (radio
15 frequency identification trackers) readers on trucks, in warehouses and tracking
16 rubber goods (sleeves and gloves used by line workers) for front line employees.
17 Benefits include decreasing the risk of having outdated assets in the field, and
18 improving the accuracy, efficiency, and accountability on the movement of
19 materials within a process.

20

21 **Q272. What are the key drivers of Systematic Tracking of Rotatable Assets?**

Line
No.

1 A272. Field tracking of assets that must be rotated in and out of the field on a regular
2 cadence and the record keeping needed to ensure that none of them remain deployed
3 beyond their expiration date is a key and critical component of DTEE's overall
4 safety program. Prior to this investment, these assets were being tracked manually.
5 A practice subject to human performance or tracking errors.

6

7 **Q273. What are the benefits of Systematic Tracking of Rotatable Assets?**

8 A273. Ensuring that all PPE is current and safe to use will reduce the likelihood of injury
9 to workers, a core value of the Company.

10

11 **Asset Management Upgrades**

12 **Q274. What is the Brigade 360 Cameras Project?**

13 A274. The Brigade 360 cameras project was an investment specifically undertaken to
14 reduce the occurrence of motor vehicle accidents and improve crew and facility
15 safety. This included installing 360-degree cameras on Distribution Operations
16 vehicles. These cameras provide additional views that allow drivers to see aerial
17 equipment hazards.

18

19 **Q275. What are the key drivers of the Brigade 360 Cameras Project?**

20 A275. DTEE's bucket and digger trucks represent a significant investment on the road,
21 and due to their size and driver visibility have some inherent challenges with
22 impacts of low hanging tree limbs, awnings, etc. Safeguarding these assets and
23 ensuring their operational efficiency is crucial for success, especially when
24 considering the limited availability of trucks in the overall market. This technology
25 investment provides for both real-time and recorded imagery for crews and allows

Line
No.

1 them to operate their vehicles with more situational awareness and higher levels of
2 safety. Between 2022 and 2023, 550 heavy-duty vehicles, 37 medium-duty
3 vehicles, and 69 light-duty vehicles were fitted with the Brigade 360 cameras.
4 Approximately 60 bucket trucks and 250 light trucks in the fleet are awaiting fitting
5 of the system.

6
7 **Q276. What are the benefits of the Brigade 360 Cameras Project?**

8 A276. Impacts with tree limbs and overhead structures happens typically more than a
9 dozen times per year and can cost as much as \$3,500 each time to repair the bucket
10 and other parts of the vehicle.

11 The Company made this investment with the goal of decreasing motor vehicle
12 incidents, measured by the Collisions per Million Miles (CPMM) metric. Since
13 inception, motor vehicle accidents have decreased from 140 (2022) to 119 (2023),
14 marking a 17% improvement. It's crucial to note that factors like inclement weather
15 and road conditions affect this metric, and this investment is part of a broader effort
16 to enhance vehicle safety. Lowering vehicle incidents not only enhances public
17 safety but also reduces expenses associated with repairing or replacing damages,
18 contributing to overall affordability of products.

19

20 **K. Mobile Technology**

21 **Q277. What is Mobile Technology?**

22 A277. Mobile Technology is a category of investments focused on creating seamless
23 transitions between on-line and off-line operations and provide integrated
24 communication, including workflows, between the control room, field leaders, field
25 crews, and supporting organizations. Mobile capabilities include both devices and

Line
No.

applications that are engineered for mobile access and usage. Applications include dispatch, work execution and forms digitization, location tracking, route navigation, analytics, and secure file sharing.

Q278. Where are the capital investment details of the projects and programs in this category?

A278. Capital investment details of these projects and programs in this category are included in:

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

Table 12 Mobile Technology Exhibit Locations

Program/Project	Exhibit A-12 Sch. B5.4	Exhibit A-23 Schedule M7	Exhibit A-23 Schedule M8
Mobile Tools Expansion	p. 18, line 50	pp. 116-119	pp. 133, 159-161
Maintain Compliance	p. 18, line 51	pp. 96-99	pp. 133, 159-161
Enhance and Expand Cybersecurity	p. 18, line 52	pp. 58-61	pp. 133, 159-161
Mobile Equipment Replacement	p. 18, line 53	pp. 108-111	pp. 133, 159-161
Mobile Technology	p. 18, line 54	pp. 112-115	pp. 133, 159-161

Mobile Tools Expansion

Q279. What is Mobile Tools Expansion?

A279. Mobile Tools Expansion is a category of investments related to tools and applications utilized by field resources. Mobile tools are a critical investment to

Line
No.

1 support operational crews and leadership drive efficiency, productivity, and safety.

2 The primary investment in this category is the Every Day Daily Plan (EDDP).

3

4 **Q280. What is Every Day Daily Plan (EDDP)?**

5 A280. The Everyday Daily Plan is a web application designed to serve as a consistent
6 "all-weather" tool for both storm and non-storm scenarios. This tool facilitates the
7 Company's response to planned and trouble work on the electric system, utilizing
8 real-time data to bundle and prioritize jobs. Customizable inputs allow for the
9 escalation of variable customer needs, such as Election Day Polling Locations and
10 School Count Day. The EDDD will work in tandem with an auto-assign function,
11 driving optimization of job and crew dispatch for the first job of the day.

12

13 **Q281. What are the key drivers of EDDP?**

14 A281. After the 2023 catastrophic ice storm the Company undertook a series of actions to
15 take advantage of system capabilities and opportunities that were never possible
16 prior to the replacement of the outdated OMS system in February of 2023. The
17 lessons learned during that storm and the capabilities that the new systems offered
18 allowed DTEE to explore opportunities within its mobile tools, which will
19 ultimately dramatically transform the ability to serve customers quickly and safely
20 as power is restored after significant storm events. This EDDP was begun as one
21 of multiple ways that DTEE will bring new capability to field teams. Historically,
22 planning and prioritizing work for the day involves using multiple databases,
23 human performance for priority evaluation, and manual phone calls. Additionally,
24 the prioritization and bundling of work during a storm utilized different tools than
25 normal operations day to day work. During storm situations a team of five

Line
No.

1 individuals worked 16 hour shifts through the night manually developing a storm
2 restoration plan for the next day. Also, during storm and during normal operations
3 the first job a crew received was manually dispatched to the crews, at times causing
4 delays for crews getting to their first job of the day, especially during high event
5 days and storms. The EDDP enables the automation of several processes, such as
6 prioritization, bundling and auto-assigning work of work, reducing manual work
7 and driving efficiency. This ultimately improves crew efficiency and enables crews
8 to get to their first job quicker, reducing restoration time for customers.

9

10 **Q282. What are the benefits of EDDP?**

11 A282. The EDDP streamlines storm and normal operations daily planning processes,
12 creating one standard process used during all weather events. This tool automates
13 daily work prioritization, budling and dispatching of the first event of the day to
14 crews in the field. The automation of this work reduces manual labor and individual
15 decision making, drives efficiency through bundling of work and geographically
16 routing, and improves restoration efforts through faster dispatching of jobs in the
17 morning. The tool will seamlessly integrate all crews, of all types, into flexible and
18 timely daily plans. The EDDP will reduce an average one hour a day per crew in
19 wait time for their first job of the day, increasing productivity and reducing
20 restoration time for customers.

21

22 **Maintain Compliance**

23 **Q283. What is Maintain Compliance?**

24 A283. DTE Electric is subject to multiple regulatory authorities and must maintain
25 compliance with the MPSC, FERC, NERC and other industry regulations and

Line
No.

1 orders. The level of regulatory and industry oversight has grown to the point that a
2 program is being undertaken to ensure successful compliance. This investment is
3 expected to grow year-over-year, especially beyond 2025 when the Company
4 anticipates the need for additional compliance components to be required on several
5 topics including but not limited to energy justice (EJ), electrification, cyber security
6 and expanding NERC requirements. Having access to accurate, timely and
7 complete operational data is key for compliance. System investments to compile
8 day-to-day operational information and demonstrate compliance are needed to
9 replace labor intensive manual methods that have been used to date.

10

11 **Q284. What are the key drivers of Maintain Compliance?**

12 A284. Real-time operational data enables DTEE to adapt to changing regulations and
13 demonstrate adherence to those changes. Investing in compliance automation to
14 meet new demands and having data accessible in a timely and cost-effective manner
15 for reporting are some examples as to why this investment is prudent.

16

17 **Q285. What are the benefits of Maintain Compliance?**

18 A285. Like any other industry the Company stewards a body of sensitive data required for
19 effective operations. This data includes electrical system, operational, customer,
20 and payment data. Many regulations and compliance mandates govern the
21 Company's use of this information and how it must be safeguarded. DTEE's
22 customers benefit from this investment when the information is collected, used, and
23 secured in such a way that the information is safeguarded both within Company
24 facilities and when in the hands of DTEE employees while serving the customer at
25 their location. Employees benefit by having ready access to the information needed

Line
No.

1 to serve wherever the work requires, knowing that mobile systems comply with all
2 the regulations that govern their job functions.

3

4 **Enhance and Expand Cybersecurity**

5 **Q286. What is Enhance and Expand Cybersecurity?**

6 A286. The Company plans to invest hundreds of millions of dollars in its grid automation
7 programs over the next decade. The automation that is placed in the field to enable
8 that automation and control must be protected from cyber-attack and that protection
9 presents unique and ever evolving challenges as bad actors will recognize this field
10 automation as a potential that they will look to exploit. This project is designed to
11 place targeted technologies, both hardware and software, into the Company's
12 infrastructure in a controlled manner to test and evaluate the most effective ways to
13 address these threats.

14

15 **Q287. What are the key drivers of Enhance and Expand Cybersecurity?**

16 A287. Industry-wide there is recognition both for the need to automate the ever evolving
17 and more complicated grid to control it in real-time and that this automation will
18 create potential vulnerabilities for outsiders to exploit. If these potential threats are
19 not addressed early in automation programs, then the opposition will gain a
20 significant advantage over the Company's ability to safely operate the grid. This
21 program will assess the cybersecurity needs for this infrastructure and inform the
22 selection of tools and techniques to combat these threats.

23

24 **Q288. What are the benefits of Enhance and Expand Cybersecurity?**

Line
No.

1 A288. Adequately understood and implemented tools and countermeasures will serve to
2 ensure that the grid is as reliable, available, and defensible as possible. Customers
3 will benefit from a more resilient, more effectively run grid, while at the same time
4 this project will be foundational in ensuring that only the authorized operators are
5 able to access and control the automation that is put in place. This is critical from
6 both a safety and an operational standpoint.

7

8 **Mobile Equipment Replacement**

9 **Q289. What is Mobile Equipment Replacement?**

10 A289. The Company has thousands of mobile devices that have been deployed to front-
11 line workers and their leadership. These devices have planned useful deployed
12 lifecycles of 6 years. The Company plans and executes device replacements yearly
13 on ~1/6th of those devices to keep the devices operational and secure.

14

15 **Q290. What are the key drivers of Mobile Equipment Replacement?**

16 A290. Up to date devices are more reliable and technically secure from cyber threats than
17 older, less capable equipment. It is important for field workers to have operational
18 and up-to-date equipment to perform their work functions safely and effectively.

19

20 **Q291. What are the benefits of Mobile Equipment Replacement?**

21 A291. Correctly functioning equipment running effectively, and up-to-date systems
22 contribute to efficient processes and work completion, an advantage to customers
23 in terms of DTEE's ability to be responsive to their needs and helps shorten outage
24 restoration times.

25

Line
No.

1 **Mobile Technology**

2 **Q292. Why has the Company chosen to represent its Mobile Technology spend more**
3 **specifically in this rate case?**

4 A292. In previous rate cases, Mobile Technology was represented in the financial exhibit
5 as the sum of several included projects and talked about at that higher level.
6 Feedback from the commission and the types of discovery questions from
7 intervenors indicate that a more itemized approach was desired so for this case that
8 category has been reworked to itemize its key investments.

9

10 **Q293. What were the key investments made in 2022 and 2023 that are Mobile**
11 **Technology?**

12 A293. The key investments grouped under the heading of Mobile Technology were
13 Outage Status App Changes for Damage Assessment, Tree Trim's Vegetation
14 Management Software Replacement Pilot Project, Service Center Wi-Fi Upgrades,
15 Lemur Pro Multiyear License Purchase and Field Service Edge Overhead
16 (OH)/Underground (UG) Enhancements.

17

18 **Q294. What is Outage Status App Changes for Damage Assessment?**

19 A294. The scope of this project was to create a capability within the Outage Status
20 Application (OSA), the mobile storm tool used by DTEE's tree trim and all foreign
21 crews for storm response, allowing automated near real time access to update
22 damage assessment from the field to planning staff.

23

24 **Q295. What are the key drivers of Outage Status App Changes for Damage**
25 **Assessment?**

Line
No.

1 A295. Over the last several years the amount and severity of damage caused by storm
2 events has increased as weather in Michigan changes for the worse. It is critical
3 that damage assessment teams get into the field and get their data back to planning
4 staffs as rapidly as possible immediately following an event. get. This project adds
5 damage assessment capability to one of DTEE's key field tools that it previously
6 did not incorporate. With the inclusion of this capability, the automated damage
7 assessment form is accessible by all damage assessors to record and provide
8 information on outage events with this information flowing into the OMS system
9 in real time as the form is completed and sent electronically.

10

11 **Q296. What are the benefits of Outage Status App Changes for Damage Assessment?**

12 A296. Having damage assessment data rapidly available allows the Company to plan
13 restoration work more accurately for any given outage event. This information
14 provides crews with advance knowledge about what types and quantities of
15 materials they may need due to the assessor's detailing of the actual location and
16 severity of the damage that has occurred. This benefits the customer in faster
17 restoration times and more accurate estimates. It also advantages the Company's
18 employees as advance notice of this kind improves the safety of the workers and
19 the efficiency of logistic response at the point of damage. A final benefit comes
20 from use of the damages assessment data to predict the needs for future events.
21 Where this data is available, it can be used to model future events and improve
22 work standards and processes. If damage levels in advance of an incoming event
23 can be better predicted, then the ability to have the right number of resources
24 deployed at the right locations will continue to improve response times, repair
25 effectiveness, and overall cost per event.

Line
No.

1 **Q297. What is Tree Trim's Vegetation Management Software Replacement Pilot**
2 **Project?**

3 A297. The Company's existing Vegetation Management system is approaching end of life
4 and will need to be replaced within the next 3-4 years. This pilot project is a key
5 component in selecting an appropriate replacement that will fulfill the business
6 outcomes needed for achieving and maintaining a 100% on cycle trimming program
7 and helping to move the Company to predictive on demand vegetation
8 management.

9
10 **Q298. What are the key drivers of Tree Trim's Vegetation Management Software**
11 **Replacement Pilot Project?**

12 A298. The replacement of DTEE's existing Vegetation Management tool will be a
13 multiyear, multi-million-dollar investment. The Company solicited multiple
14 companies through a formal RFP and selected an initial preferred partner. To verify
15 this selection a pilot project was undertaken to demonstrate the capabilities of that
16 selected software to further validate the selection before accepting the final
17 statement of work for the larger program. The activities within the pilot will allow
18 the team to experience firsthand the software, participate in configurations based
19 on key business requirements, experience onsite training, perform device setup,
20 engage in ongoing Q&A and evaluate vendor support throughout pilot program.
21 All these activities will validate the front runner's solution in the Company's
22 environment and shorten overall implementation of a final product. Choosing a
23 vendor without piloting the software beforehand may lead to receiving a product
24 that does not meet expectations.

25

Line
No.

1 **Q299. What are the benefits of Tree Trim's Vegetation Management Software**
2 **Replacement Pilot Project?**

3 A299. The pilot program is a key piece in evaluation of a potential work management
4 software replacement for Tree Trim. The pilot will highlight key business
5 functionality requirements for field and back-office users, with the goal of finding
6 and addressing any functionality discrepancies between the RFP requirements and
7 the actual vendor product prior to the beginning of the project.

8

9 **Q300. What is the scope of the Service Center Wi-Fi Upgrades?**

10 A300. The project scope was to upgrade current Wi-Fi Infrastructure at all Service Centers
11 including Warren and the Technical Development center (TDC). It included
12 installation of additional Wi-Fi capacity / coverage. With increase of over 100%
13 in the number of mobile devices in use by teams at decentralized locations (MDTs,
14 laptops, tablets, and phones) and the increase in the size of the area that had to be
15 covered at each location, the existing Wi-Fi footprint and capacity had to be
16 increased. Addressed coverage issues inside the building and reconfigured existing
17 layout to meet updated requirements. The project also added outdoor coverage in
18 the parking areas, truck bays and garages.

19

20 **Q301. What are the key drivers of Service Center Wi-Fi Upgrades?**

21 A301. Service Center demand on Wi-Fi has increased over time. Existing capacity and
22 area of coverage was no longer sufficient to support the increased usage of mobile
23 devices like MDTs, laptops, tablets, and phones. It became necessary to increase
24 indoor and outdoor Wi-Fi capacity and coverage at 15 locations (13 Service
25 Centers, Warren Center and the TDC.) Field personnel will be able to connect to

Line
No.

1 proper applications and will have appropriate bandwidth to run applications and
2 obtain data on the network.
3

4 **Q302. What are the benefits of Service Center Wi-Fi Upgrades?**

5 A302. With this investment employees will be able to use their mobile tools anywhere on
6 service center property to transfer data and software updates. The original Wi-Fi
7 designs at these locations were built with the assumption that any data intensive
8 transfers (e.g., maps, software patches, and operating system updates) to mobile
9 devices would be accomplished through a wired interface with only. This limited
10 how often and how time consuming these transfers were, which in turn limited the
11 number of changes that were made. As business needs have evolved and the
12 frequency of these activities has increased a different solution was needed. As a
13 result, the process for these activities went from monthly or quarterly wired updates
14 to on demand wireless ones. This is now possible as this technology has matured,
15 and its capabilities have improved. Wireless has the capacity to deliver large
16 updates and handle hundreds of connections over longer distances.
17

18 **Q303. What is Lemur Pro License Purchase and why is it necessary to have these**
19 **licenses?**

20 A303. Purchase of 3-year Lemur Pro license renewal was completed in 2023. Lemur Pro,
21 from Locana, is the application used by the OH/UG/PSR field resources to access
22 the As-Built maps of the electrical system. It provides access to the maps and
23 equipment attribute information in both connected and disconnected/offline
24 conditions. Crews can see the location of their work in relation to circuits and other
25 equipment as well as the location of other crews and contractors.

Line
No.

1 **Q304. What are the key drivers of Lemur Pro License Purchase?**

2 A304. By purchasing a 3-year license agreement with Locana the Company, and by
3 extension the customers, can be protected From unanticipated price increases and
4 by ensuring the level of warranty support that is provided by DTEE's vendor
5 partner.

6

7 **Q305. What are the benefits of Lemur Pro License Purchase?**

8 A305. Cost containment and Warranty support inclusion are the main benefits of this
9 investment.

10

11 **Q306. What is Field Service Edge (FSE) for Overhead and Underground crews?**

12 A306. Field Service Edge (FSE) was deployed in Feb 2023 for electric field operations
13 and Overhead (OH) and Underground (UG) crews. The FSE mobile application is
14 being used to allow OH/UG field resources to receive trouble job assignments and
15 details associated with those jobs. At the initial launch, the Company had
16 implemented the same feature set that was originally planned for the Compass
17 mobile tool before Compass was retimed to after go-live. Once in place and in use
18 it was determined that this tool could enable additional features that would
19 contribute to improved storm restoration efforts.

20

21 **Q307. What are the key drivers of FSE for OH/UG?**

22 A307. After the catastrophic ice storm in February of 2023 the Company focused on
23 improving storm restoration processes. Adding additional capability to the primary
24 field tool was determined to be an important investment. This led to a series of
25 enhancements to the system based on storm improvement efforts and feedback from

Line
No.

1 the field and dispatch teams on improvements to the usability of the FSE mobile
2 app.

3 Some of the Field Service Edge (FSE) enhancements that were deployed to the
4 overhead/underground field crews in 2023 include:

- 5 • Consolidated input screens: Changes in how field crews will handle accelerated
6 storm restoration led to an opportunity to consolidate some of the input screens
7 that the crews interact with and ensures that all of them most important
8 information in a simplified workflow.
- 9 • Added an assignment prioritization grid view that closely mimics that same
10 functionality at a dispatchers station in the OMS. This view now highlights
11 priority jobs, allows sorting and filtering to help crews focus during storms
12 rather than a first in first out flow that was typical of the original product
13 delivery.
- 14 • Implemented bulk updates and quick completions for common issues.
- 15 • Added the ability to view all the crew's current assignments on a map to assist
16 in geographically tracing wire downs and circuit issues. This type of analysis
17 function was previously found at the dispatch level, but this allows movement
18 of that awareness and decisioning to the point of activity.
- 19 • Simplified the meter exchange job flow and allowed bar code scanning for
20 serial numbers to accomplish routine tasks often associated more rapidly with
21 restorations.
- 22 • Added link to report of all crews working on the same circuit to help with
23 situational awareness.
- 24 • Improve data quality by enabling required functionality for specific data fields
25 and formatting of data being sent back to OMS.

Line
No.

1 **Q308. What are the benefits of FSE for OH/UG?**

2 A308. The above-described enhancements to workflows and screen consolidations have
3 been implemented, all of which are integral components to improve storm
4 restoration efforts.

5

6 **Q309. Does this complete your direct testimony?**

7 A309. Yes, it does.

DTE Pilot Informational Document

Project Name: Adaptive Networked Microgrid (ANM)
Included with Case: Case No. U-21534
Sponsoring Witness: Shannen M. Hartwick

(1) Pilot need and goals	
a. Need for the pilot is expressed. Results of similar pilots and findings are shared to justify the need for the proposed pilot.	• Customer reliance on the electric system will continue to grow with additional electrification, driving the expansion of clean energy alternatives • DTEE is executing a series of all renewable, Non-Wires Alternative (NWA) projects that will expand future DER use and the learnings will be used to implement the ANM technology • The MPSC has communicated its desire for Michigan utilities to pursue IIJA Federal funding grants to support providing affordable, reliable, and equitable power to the State's citizens
b. Pilot goals and desired learnings are detailed	• Develop, test, and refine the concept of ANMs with two real-world deployments, in a rural and urban area. • Partner with the research and development community to both share lessons learned and gain insights from that community • Build industry's confidence in the new ANM technology to increase implementation on the system
c. Reference any pending applicable regulatory dockets, legislation, or other consideration relevant to the pilot project.	Selection of Application for Negotiation Under Funding Opportunity Announcement Number DE-FOA-0002740, BIL – Grid Resilience and Innovation Partnerships (GRIP), Topic Area 2

(2) Pilot design and evaluation plan designed and presented together

a. Pilot design and evaluation plan designed and presented together

Measures will include the following:

- Leveraging DER for greater customer reliability
- Position Michigan with technical expertise in developing the future electrical system
- Progress technology outside the NWA and microgrid space

Seven areas of focus for Development and Testing:

- Project and Technical Management – The Company will focus on good project management practices to manage the scope within budget and schedule. A major aspect of the technical management plan will be to develop good specifications early and refine them based on what is learned as the project progresses.
- Sensors and Data Analytics – The greater flexibility offered by ANMs will require greater visibility into the electrical system. This will include deploying and using sensors with advanced machine learning applications such as fault locating, forecasting, and state estimation.
- Cybersecurity – ANMs will include deploying more grid-edge devices, increasing the attack surface for cybersecurity concerns. The Company has a plan to continuously identify threats, simulate countermeasures, and deploy those countermeasures.
- Control and Protection – Advanced controls is a critical area to tie the microgrids together to make the sectionalizing, forecasting, equipment, and other aspects work together. The dynamic boundaries of ANM will also require protection to evolve from a single setting to situationally aware or adaptive settings.
- Engineering Due Diligence – Prior to field deployments, the Company will complete several steps to ensure the safe and proper operation of the new technology. This will occur through simulations and testing at the Company's Solar and Storage Lab in Westland, Michigan.
- Microgrid Deployment – This area of focus takes the projects through the Company's gate process of engineer, design, construct, and closeout.
- Sharing Lessons Learned – The Company will leverage lessons learned in the industry to make the project progress as efficiently as possible. In the spirit of collaboration, the Company will also share what it is learning during the project.

b. If applicable, define target customer population, selection rationale, recruitment plans, and evaluation plans for customer adoption and satisfaction.	Develop and deploy pilot technology to benefit customer population in includes rural and urban areas.
c. If statistical analysis will be conducted on pilot results, a statistically significant sample size must be selected, supported, and detailed. If a statistically significant sample size is not selected, justification must be provided	The benefits and functional performance will be monitored at the two pilot locations and projected for potential future deployments. These benefits will be compared to the costs of the project and projected cost of potential future deployments.
d. If statistical analysis will not be conducted, justification must be provided as well as an approach for evaluating pilot goals.	Specific statistical analyses will not be conducted, but DTE will be collecting and tracking a variety of metrics to measure: • Demand impact compared to expectation • Deployment time • Deployment costs • Reliability impact compared to expectation

(3) Pilot project costs detailed					
a. Project costs are detailed by source and amount for all applicable periods		~~2021~~2024	~~2022~~2025	~~2023~~2026	~~2024~~2027
	DTEE	\$1,976,607	\$12,437,241	\$6,047,973	\$1,359,926
	Partners	\$317,697	\$338,633	\$337,786	\$125,183
	DOE	\$2,294,003	\$12,774,310	\$6,385,303	\$1,484,878
	Total	\$4,588,307	\$25,550,184	\$12,771,062	\$2,969,987
b. Availability of non-utility funding and whether any was pursued (such as state or federal funding opportunities) described	50% cost sharing with DOE as a part of the grant – IJJA refer to above				
c. Projected cost-effectiveness of piloted measure at scale over expected life described	The NWA solution is a pilot to assess if this technology is cost effective compared to our traditional restoration methods.				
d. Proposed rate recovery approach detailed	Capital investment proposed for recovery in the instant case				

(4) Pilot timeline detailed	
a. Proposed timeline for the pilot project and any related reports or evaluations delineated.	• Engineering Phase – 2024 ○ Specifications will be developed for the individual components and overall system. ○ Software (CYME and PSCAD) simulations will be completed. ○ The engineering needed for the Port Austin and O’Shea deployments will be finalized. ○ Achieving regulatory support is a gate to move forward past this phase. • Development Phase – 2025 ○ With regulatory and DOE support in place, the project will ramp-up significantly in phase 2. ○ Material will be ordered, design will be completed, and construction will start. ○ The specifications developed in phase 1 will be implemented by the team in phase 2. ○ Grid-edge and ADMS software will be developed, tested, and refined. ○ Hardware-in-the-loop testing will be completed. ○ Westland Equipment Yard testing will start. ○ Initial drafts of standards will be developed. ○ Initial testing, operating and maintenance procedures will be completed. • Deployment Phase – 2026 ○ After the successful completion of development work and engineering due diligence in phases 1 and 2, ANMs will be deployed in the field on two distribution circuits. • Assessment Phase – 2027 ○ With ANM deployments completed at Port Austin and O’Shea, the team will focus on monitoring the performance and benefits of the new technology.

(5) Stakeholder engagement plan detailed

a. Stakeholder engagement plan before, during, and after pilot takes place detailed	Partner with Staff for pilot review. Below is a table that describes the roles of the stakeholder partner organizations: <table border="1"> <thead> <tr> <th>Organization</th><th>Role</th></tr> </thead> <tbody> <tr> <td>DTE Electric</td><td>Perform end-to-end project management. Complete engineering due diligence and testing. Implement engineering, design, and construction</td></tr> <tr> <td>Open Systems International (OSI)</td><td>OSI is the Company's ADMS supplier. The ADMS will be a key aspect of this advanced technology, and OSI will develop the centralized aspects of the control and forecasting needs.</td></tr> <tr> <td>Open Energy Solutions (OES)</td><td>Integrate advanced microgrid logic for grid-edge devices into an interoperable communication and control network between microgrid equipment.</td></tr> <tr> <td>Electric Power Research Institute (EPRI)</td><td>Viability analysis for networked microgrids, laboratory test plan development for networked microgrid controls and protection systems, flexible protection design and implementation for networked microgrids and factory and site acceptance test planning for networked microgrid controls and grid-forming inverters.</td></tr> <tr> <td>University of Michigan - Dearborn</td><td>Support the development and testing of cybersecurity practices. Also, develop a series of workshops in which industrial and national lab members, faculty, and students can share technical skills, internship opportunities, and other follow-on collaboration opportunities.</td></tr> <tr> <td>Lawrence Livermore National Laboratory (LLNL)</td><td>An advisor to the project on the development of black start technology, integration and optimal algorithms, de-energized line testing for public safety. Design and deployment of basic microgrids</td></tr> <tr> <td>National Renewable Energy Laboratory (NREL)</td><td>An advisor to the project on the development of distribution systems state estimation and microgrid control and monitoring.</td></tr> </tbody> </table>	Organization	Role	DTE Electric	Perform end-to-end project management. Complete engineering due diligence and testing. Implement engineering, design, and construction	Open Systems International (OSI)	OSI is the Company's ADMS supplier. The ADMS will be a key aspect of this advanced technology, and OSI will develop the centralized aspects of the control and forecasting needs.	Open Energy Solutions (OES)	Integrate advanced microgrid logic for grid-edge devices into an interoperable communication and control network between microgrid equipment.	Electric Power Research Institute (EPRI)	Viability analysis for networked microgrids, laboratory test plan development for networked microgrid controls and protection systems, flexible protection design and implementation for networked microgrids and factory and site acceptance test planning for networked microgrid controls and grid-forming inverters.	University of Michigan - Dearborn	Support the development and testing of cybersecurity practices. Also, develop a series of workshops in which industrial and national lab members, faculty, and students can share technical skills, internship opportunities, and other follow-on collaboration opportunities.	Lawrence Livermore National Laboratory (LLNL)	An advisor to the project on the development of black start technology, integration and optimal algorithms, de-energized line testing for public safety. Design and deployment of basic microgrids	National Renewable Energy Laboratory (NREL)	An advisor to the project on the development of distribution systems state estimation and microgrid control and monitoring.
Organization	Role																
DTE Electric	Perform end-to-end project management. Complete engineering due diligence and testing. Implement engineering, design, and construction																
Open Systems International (OSI)	OSI is the Company's ADMS supplier. The ADMS will be a key aspect of this advanced technology, and OSI will develop the centralized aspects of the control and forecasting needs.																
Open Energy Solutions (OES)	Integrate advanced microgrid logic for grid-edge devices into an interoperable communication and control network between microgrid equipment.																
Electric Power Research Institute (EPRI)	Viability analysis for networked microgrids, laboratory test plan development for networked microgrid controls and protection systems, flexible protection design and implementation for networked microgrids and factory and site acceptance test planning for networked microgrid controls and grid-forming inverters.																
University of Michigan - Dearborn	Support the development and testing of cybersecurity practices. Also, develop a series of workshops in which industrial and national lab members, faculty, and students can share technical skills, internship opportunities, and other follow-on collaboration opportunities.																
Lawrence Livermore National Laboratory (LLNL)	An advisor to the project on the development of black start technology, integration and optimal algorithms, de-energized line testing for public safety. Design and deployment of basic microgrids																
National Renewable Energy Laboratory (NREL)	An advisor to the project on the development of distribution systems state estimation and microgrid control and monitoring.																
b. Interim and final stakeholder reporting described	Future rate case and distribution grid plan filings																
c. Expected publicly available data from pilot shared	Lessons learned from the project will be shared in technical papers, annual information sessions with the technical community, periodic discussions with the MPSC Staff, and through other channels. Critical Electrical Infrastructure Information (CEII), customer information will not be shared.																

(6) Public interest detailed

a. Pilot support of the transition to clean, distributed energy resources, and its expected impacts described.	- Utilize the DER technology to integrate distributed energy resources for a smarter grid - Reduce emissions compared to the use of traditional portable diesel generators

	Implemented advanced technology solutions faster and for lesser costs than the traditional solutions for customer reliability
b. Any added benefits to ratepayers or the energy delivery system, either due to proposed site selection or through other pilot variables, especially if any system weaknesses or forecasted needs are addressed, shared.	New technologies such as batteries are becoming available for utilities to use to solve traditional electrical system concerns. Using these solutions for advanced microgrids will provide additional reliability and customer benefits
c. Expected impacts of the piloted measure on reliability, resilience, safety, and ratepayer bills detailed.	Utilize DERs for system resiliency and reliability
d. Expected local or Michigan based employment and business opportunities created by pilot described.	The Company utilizes Michigan based service providers wherever possible
e. Any potential impacts or added benefits of the pilot on low-income customers, seniors or other vulnerable populations described.	Reduce emissions compared to the use of traditional portable diesel generators in communities of vulnerable populations. Additionally, one of the two planned areas for construction of the microgrid (the O'Shea Solar Park project) is located directly within an environmental justice community (EJ). This will benefit the EJ area and support the neighboring areas as well.
f. Any other public benefits detailed.	N/A

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

ALLEN J. KRYSCYNSKI

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

Line
No.

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

2 A1. My name is Allen J. Kryscynski (he/him), and my business address is One Energy
3 Plaza, Detroit, Michigan, 48226 and 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.

8

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

10 A3. I earned a Bachelor of Science from the University of Michigan School of Natural
11 Resources and Environment with a dual concentration in environmental policy and
12 natural resource management. I also received a master's degree in Business
13 Administration (MBA) from the University of Michigan.

14

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

16 A4. I held several positions with ITC Holdings including Senior Regulatory Analyst
17 and a variety of positions within the Local Community and Community Affairs
18 team culminating as a Senior Local Government and Community Affairs
19 Representative. At ITC Holdings, I worked on FERC and MISO regulatory issues
20 and represented ITC Holdings at community meetings to gain approval for new
21 transmission substations and transmission lines.

22

23 I joined DTE Energy in 2014 as a Strategy and Corporate Development Associate
24 in the Corporate Strategy group. In this role, I did work on the initial Distribution

Line
No.

1 Operations (DO) investment strategy project to determine distribution grid
2 investment needs as well as work on DTE workforce projections and requirements
3 for both the Distribution Operations and Fossil Generation business units. In 2016,
4 I was appointed Manager of Distribution Operations Strategy and assumed
5 responsibility for continued work to evolve the distribution operations investment
6 strategy, operations strategy, and the chief of staff role for the Senior Vice President
7 of Distribution Operations. In early 2018, I was appointed Manager in Project
8 Management with responsibility to start up and operationalize the 4.8kV Hardening
9 Program to remove City of Detroit Arc Wire and harden the City of Detroit
10 electrical infrastructure. Later in 2018, I was appointed Manager of Tree Trim
11 Strategy where I was responsible for managing the initial Tree Trim Surge rate case,
12 Tree Trim contractor negotiations, and the overall Tree Trim strategy for
13 scheduling work, and ensuring there was an adequate supply of tree trimmers
14 necessary to complete the work. In 2020 I took over the Tree Trim Operations
15 Manager position and managed day to day Tree Trim operations including
16 overseeing all of DTE's internal arborists and foresters as well as eight tree trim
17 contractors and their 1,600+ employees. In 2022 I was appointed as Manager of
18 Distribution Operations Regulatory Strategy and Grid Modernization and promoted
19 to Acting Director in 2023.

20

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

22 A5. As Director of Distribution Operations Regulatory Strategy and Grid
23 Modernization, my current responsibilities are two primary focus areas: 1)
24 managing Distribution Operations regulatory activities – including rate cases, the
25 distribution grid plan filing, required reporting, and various Company/MPSC

Line
No.

1 collaboratives, and 2) Distribution Operations long term grid modernization
2 strategy and the distribution grid plan (DGP).

3

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

6 A6. Yes. I sponsored testimony in Case No. U-21297. In addition, I supported Tree
7 Trim testimony and witnesses in U-20162, U-20561, and U-20836.

Line
No.

1 **Purpose of Testimony**

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

3 A7. The purpose of my testimony is to support, as reasonable and necessary, the
4 historical Operations and Maintenance (O&M) expenses related to electric
5 distribution activities for 2022 historical period and for the projected test period 12-
6 months ending December 31, 2025. Additionally, my testimony describes the (1)
7 Distribution Operations Overview which includes an introduction to the other
8 witnesses from Distribution Operations in this case and System Performance,
9 Overview, (2) Distribution Rate Request, (3) Distribution O&M, (4) Distribution
10 Grid Plan (DGP) Overview, (5) Strategic Capital Overview, (6) Overview of the
11 capital exhibits – Exhibit A-12 Schedule B5.4, and Exhibit A-23 Schedules M4,
12 M5, M6, and M7, (7) Variances between the 2022 actuals and the forecast in Case
13 No. U-21297 in Exhibit A-12 Schedule M1; projected capital expenditures
14 forecasted in Case No. U-21297 for calendar years 2023 and 2024 and the project
15 capital expenditures in this case for calendar years 2023 in Exhibit A-12 Schedule
16 M2 and 2024 in Exhibit A-12 Schedule M3, (8) Distribution Operations' Global
17 Prioritization Model (GPM) and Exhibit A-23 Schedule M14, (9) the Company's
18 Capital/Reliability Projection Model (10) Infrastructure Investment and Jobs Act
19 (IIJA) funding grants, (11) Updates on the Distribution Operation's approach to
20 Environmental Justice (EJ), and (12) Coordination Processes in place with local
21 municipalities.

22

23 I will discuss the capital exhibits and overview while the reasonableness and
24 prudence of each specific capital investments will be supported by other DO
25 witnesses.

Line
No.

1

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

3 A8. My testimony consists of twelve parts:

4 Part I Distribution Operations Overview and System Performance

5 Part II Distribution O&M and Capital Rate Request

6 Part III Distribution O&M Overview and Exhibits

7 Part IV Distribution Grid Plan (DGP) Overview

8 Part V Strategic Capital Overview

9 Part VI Capital Exhibits Description

10 Part VII Capital Investment Variance Discussion

11 Part VIII Global Prioritization Model

12 Part IX Capital/Reliability Model

13 Part X IIJA Grant Opportunities

14 Part XI Environmental Justice

15 Part XII Municipal Project Coordination

16

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

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

19 Exhibit Schedule Description20 A-13 C5.6 Projected Operation and Maintenance Expenses –
21 Distribution Expenses22 A-23 M1 Revised U-21297 2022 Forecast vs. U-21534 Comparison23 A-23 M2 Revised U-21297 2023 Forecast vs. U-21534 Comparison24 A-23 M3 Revised U-21297 2024 Forecast vs. U-21534 Comparison

25 A-23 M8 2023 Distribution Grid Plan, MPSC Case No.

Line
No.

1 20147
2 A-23 M14 GPM Project and Program Rankings

3

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

5 A10. Yes, they were.

6

7 **Part I: Distribution Operations Overview and System Performance**

8 Distribution Operations Organization

9 **Q11. Can you please describe the organization that manages the investments**
10 **included in the exhibits you are sponsoring?**

11 A11. Distribution Operations (DO) is the organization that manages the investments
12 included in the exhibits I am sponsoring. The organization focuses on the design,
13 maintenance, and operation of the Company's electrical distribution system and
14 subtransmission system, which together are often referred to as "the distribution
15 system." DO is comprised of nine suborganizations, described below.

16

17 (i) Central Engineering: This organization is responsible for determining,
18 maintaining, and improving the health of the Company's electric
19 distribution assets, which includes defining technical standards for
20 distribution equipment, long-term system planning including grid
21 modernization, and developing major projects needed for customer
22 connections, relocations, increasing loads, infrastructure improvements,
23 reliability upgrades, and technology enhancements.

24

Line
No.

- 1 (ii) Regulatory Strategy and Grid Modernization: This organization is
2 responsible for two primary areas of focus: 1) Distribution Operations’
3 long term grid modernization strategy and the distribution grid plan (DGP)
4 and, 2) Distribution Operations regulatory activities – including rate cases,
5 the distribution grid plan filing, MPSC required reporting, and conducting
6 and organizing the numerous collaborations ordered by the MPSC.
7
8 (iii) Scheduling & Construction: This organization is responsible for: 1)
9 scheduling all planned work for both DTE and contractors’ field crews on
10 overhead and underground distribution, subtransmission, and substation
11 assets; 2) leading systematic approaches to track and measure work,
12 streamlining business processes and routine tasks, and governing the
13 Maximo Business Process that coordinates team collaboration and
14 workflows across all levels of the organization; 3) planning, and field
15 oversight of out-of-state storm resources when required for large storm
16 events; 4) contractor accounts payable and invoicing, unitization of capital
17 investments, and conducting field quality inspections to validate
18 construction is built to standards and specifications; 5) governance of the
19 DO Safety, Human Performance, and Hazardous Energy Control
20 programs.
21
22 (iv) Operational Technology: This organization is responsible for Advanced
23 Metering Infrastructure (AMI) system enhancements and operations,
24 meter engineering and metrology, equipment calibration, grid mapping
25 including analytics, and working with business units within Distribution

Line
No.

1 Operations to define, implement, and support technology and analytical
2 solutions including our Storm Excellence investments in support of our
3 storm restoration efforts. The organization also manages the Advanced
4 Distribution Management System (ADMS), which provides the
5 technological capabilities to monitor and operate the grid, respond to
6 emergency conditions and outages, and facilitates the deployment of
7 distributed energy resources.

8

9 (v) Regional Customer Operations: This organization is responsible for
10 overhead and underground emergent work, short-cycle (typically less than
11 a year) construction, new service and meter installations, and design and
12 planning focused on short-cycle reliability, and customer-requested work.

13

14 (vi) System Operation: This organization includes the Company's Electric
15 System Operations Center (ESOC), where DTE Electric monitors and
16 controls the electrical system to maintain a reliable and secure flow of
17 electric power.

18

19 (vii) Emergency Preparedness & Response "EPR": This organization plans
20 efforts to reduce the time customers spend without power and develops,
21 maintains, manages DO's incident response procedures and storm events
22 and enhances storm process for customers through improved
23 communication. EPR has expanded the organization with a pointed focus
24 on improving storm restoration processes and enhancing the Company's
25 ability to efficiently restore customers in "extreme weather" scenarios,

Line
No.

1 such as recent storms our customer base has been experiencing. EPR is
2 comprised of six groups (strategy, public safety, damage assessment,
3 Regional ICS, Productivity, and Event management). The team has set
4 individual targets within each group and has initiated projects focused on
5 addressing the gaps identified from previous storms. All of this work is
6 aligned to a broad strategic plan focused on improving day to day
7 emergent operations and storm processes.

8

9 (viii) Tree Trimming: This organization plans, communicates, and implements
10 the Company's tree trimming program.

11

12 (ix) Substation Operations: This organization is responsible for the operation
13 and maintenance of all the substations within the DTE Energy service
14 territory.

15

16 **Q12. Have there been any significant changes to the DO organization since the filing**
17 **of U-21297?**

18 A12. Yes. To better support the increasing construction for grid investments, a Project
19 Management Office (PMO) was created by merging the DO project organization
20 with DTE's Major Enterprise Projects (MEP) group to consolidate project
21 management expertise in one group. This new organization is responsible for
22 management and execution of the majority of Strategic Capital projects and
23 programs for Distribution Operations, as well as large investment projects for other
24 areas of DTE. The organization consists of the project managers, cost engineers,
25 schedulers, project estimators, and the leadership/support teams required to manage

Line
No.

1 and track the progress of DO's capital investments. The PMO has focus on driving
2 cost efficiency, managing project scope and schedule, and is specifically targeting
3 challenges in labor cost and availability, supply chain constraints and material
4 availability, as well as obtaining needed land, permits, and easements. Some
5 smaller programs and projects are still managed within the DO organization.

6

7 **Q13. How is the Distribution Operations testimony organized in this case?**

8 A13. Distribution Operation (DO) capital and O&M expenditures, as well as other
9 activities, are supported by six (6) witnesses in this case. Together these witnesses
10 discuss the reasonableness and prudence of DO capital and O&M expenditures,
11 exhibit content, tree trim, Environmental Justice (EJ), and other topics related to
12 DO. A high level summary of these six witnesses' scope of testimony is introduced
13 below:

- 14 1) Witness Allen J. Kryscynski is the Distribution Operations Regulatory Strategy
15 and Grid Modernization. The purpose of my testimony is described above.
- 16 2) Witness Brian Hill is the Director Southwest Regional Customer Operations and
17 Scheduling & Coordination. The purpose of witness Hill's testimony is to
18 support as reasonable and prudent the investments in base capital programs,
19 Emergent Replacements and Customer Connections, Relocations & Other.
- 20 3) Witness Morgan Elliott Andahazy is the Director of PMO Programs. The
21 purpose of witness Elliott Andahazy's testimony is to support, as reasonable and
22 prudent, investments in the strategic capital pillar Infrastructure Resilience and
23 Hardening.

Line
No.

- 1 4) Witness Satvir Deol is the Director of Engineering. The purpose of witness
2 Deol's testimony is to support, as reasonable and prudent, investments in the
3 strategic capital pillar Infrastructure Redesign and Modernization.
- 4 5) Witness Shannen Hartwick is the Director of Automation for DO. The purpose
5 of witness Hartwick's testimony is to support, as reasonable and prudent,
6 investments in the Technology and Automation pillar including Grid
7 Automation, Grid Automation Telecommunication, AMI and ADMS projects,
8 and the Electric System Operations Center (ESOC) and Alternate System
9 Operations Center (ASOC) projects, and other operational technology
10 investments.
- 11 6) Witness Rachel Steudle is the Director of Tree Trim. The purpose of witness
12 Steudle's testimony is to (1) discuss the importance of and progress made in
13 DTE Electric's vegetation management ("Tree Trimming") program, (2)
14 provide details related to the Company's Tree Trimming Surge Program that
15 will deliver on the reliability goals established in the Company's Distribution
16 Grid Plan (DGP), (3) describe the customer benefits of the Company's Tree
17 Trimming Surge Program to date, (4) support the Operations and Maintenance
18 (O&M) expenses related to tree trimming efforts for the historical test period
19 ending December 31, 2022, and the projected base O&M expenses and the Tree
20 Trimming Regulatory Asset Surge funding amount for January 1, 2025, to
21 December 31, 2025, (5) request approval of incremental Surge funding for 2025,
22 (6) discuss the future of the Tree Trimming program once the Surge is
23 completed, (7) address the additional requests from U-21297.

Line
No.

1 Electrical System Overview

2 **Q14. Can you briefly describe the electrical system that the Company owns and**
3 **operates?**

4 A14. The Company owns and operates approximately 31,000 miles of overhead
5 subtransmission and distribution lines, and 16,830 miles of underground
6 subtransmission and distribution lines. The Company's service territory
7 encompasses approximately 7,600 square miles and includes approximately 2.3
8 million residential, commercial, and industrial customers. Additional key statistics
9 are listed in **Tables 1 – 4.**

10

11 **Table 1 DTE Electric Substations by Type and Voltage**

Substation Type	Total Number of Substations	Number of Substations by Circuit/Low Side kV							
		4.8	8.3	13.2	4.8&13.2	24	40	24&40	Other
General Purpose	542	244	4	243	30	4	13	3	1
Single Customer	145	49	0	86	1	0	0	0	9
Customer Owned	102	NA	NA	NA	NA	NA	NA	NA	NA
Total	789	293	4	329	31	4	13	3	10

12

13 **Table 2 DTE Electric Transformers by Voltage Level**

Voltage Level	Number of Transformers	kVA Capacity
Substation - Subtransmission	178	13,085,000
Substation - Distribution	1,449	24,093,221
Distribution - Overhead and Pad-mount	451,919	33,078,863
Total	453,546	70,257,084

14

Line
No.

1

Table 3 Distribution Circuits and Line Miles

Bus Voltage	Number of Circuits	Overhead Miles			Underground			Total Miles	Total Customers
		13.2 kV	8.3 kV	4.8 kV	13.2 kV	8.3 kV	4.8 kV		
13.2 kV	1,269	11,796	16	5,596	10,710	1	417	28,535	1,030,999
8.3 kV	13	0	45	0	1	18	0	63	8,202
4.8 kV	1,991	31	0	11,064	274	0	1,937	13,307	1,213,025
Total	3,273	11,828	60	16,660	10,985	18	2,354	41,905	2,252,226

2

3

Table 4 Subtransmission Circuits and Line Miles by Substation Bus

Voltage	Number of Circuits	Overhead Miles	Underground Miles	Total Miles
120 kV	68	59	8	67
40 kV	326	2,353	466	2,819
24 kV	242	177	732	909
Total	636	2,589	1,206	3,795

4

Voltage

5

6 **Q15. What is the difference between the Company's distribution and**
7 **subtransmission voltages?**

8 A15. Voltage and purpose distinguish the difference between the Company's
9 subtransmission system and distribution system. The Company operates
10 subtransmission voltages of 24kV, 40kV, and 120kV and this infrastructure is
11 designed to feed substations that convert the voltage to distribution levels, although
12 some larger industrial customers are fed directly from subtransmission. The
13 Company currently operates distribution voltages of 4.8kV, 8.3kV, and 13.2kV and
14 this infrastructure is designed to feed the circuits that provide power to customers.

Line
No.

1

2 **Q16. How are the Company's distribution and subtransmission voltages distributed**
3 **throughout the service territory?**

4 A16. **Figure 1** illustrates the location of the Company's substation equipment voltages.
5 There are some substations that operate at 13.2kV but have parts of circuits that
6 operate at 4.8kV.

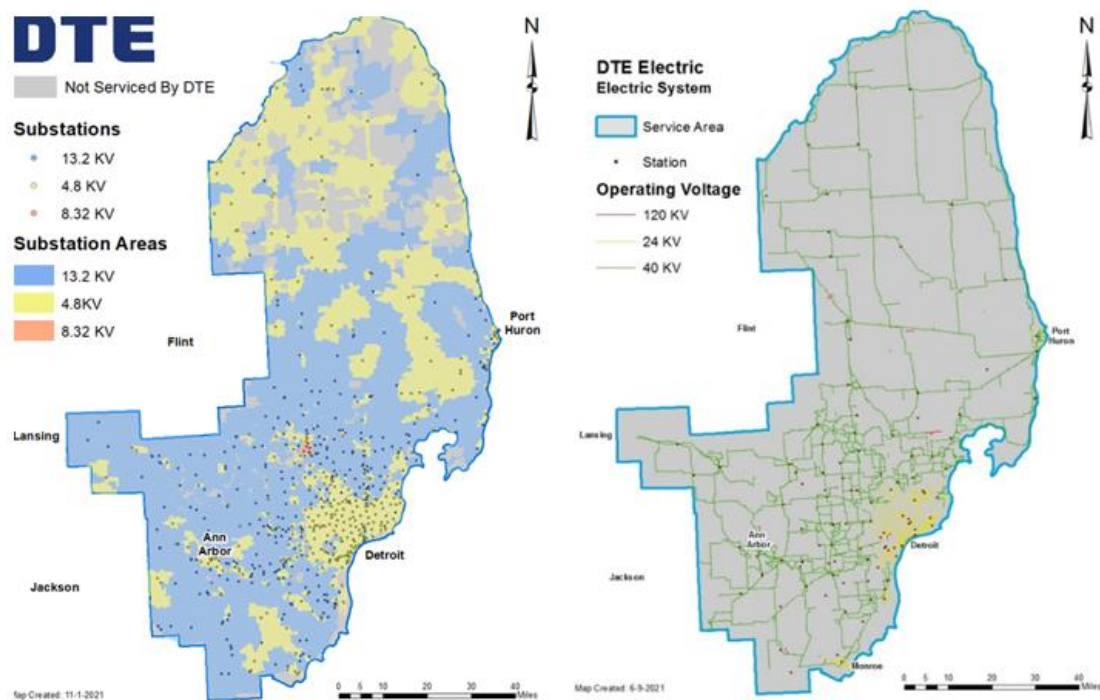
7

**Figure 1 Location of Distribution and
Subtransmission Voltages**

8

9

10



11

12 **Q17. What is the age of the Company's distribution system assets?**

13 A17. **Table 5** provides the average age and age range of the Company's key distribution
14 assets along with the life expectancy and demonstrates that the Company's assets
15 are relatively aged. For some asset classes, poles for example, the average age and

Line
No.

1 the industry life expectancy of the asset are close to the same which can be an
2 indicator of challenges to current and future equipment health. While not the only
3 factor impacting reliability, age can become a significant factor when replacement
4 parts become unavailable or in the specific cases where asset health deteriorates
5 sharply with age. Eight of the 18 asset classes have an average age at or near the
6 life expectancy.

Line
No.

1

Table 5 Asset Age Summary

Asset (Section)	DTE Electric Age Range (Years)	DTE Electric Average Age (Years)	Life Expectancy (Years)	% of Asset Class at or Beyond End of Life
Substation Power Transformers	0-99	43	40-45	49%
Network Bank Transformers	0 – 85+	46	20 - 30	91%
Circuit Breakers	0 – 90	41	30 – 40	60%
Circuit Switchers	0 – 36	19	NA	NA
Relays	0-60+	33	15-50	NA
Switchgear	0 – 70	40	40	55%
Poles	0-90+	48	40-50	50%
Three-phase Reclosers	0-34	10	20	10%
SCADA (Supervisory Control and Data Acquisition) Pole Top Switches	0-31	15	20	38.5%
40 kV Automatic Pole Top Switches	0-50+	21	40	35%
Overhead Capacitors	Oldest: 25+	NA	20	NA
Overhead Regulators	Oldest: 25+	NA	20	NA
System Cable	0 – 100+	49	20 – 40	64%
Underground Residential Distribution (URD) Cable	0 – 60+	26	40	23.6%
Manholes	1-100+	78	Varies based on construction and field conditions	NA
Advanced Metering Infrastructure (AMI meters)	0-13	6.5	20	0%

Line
No.

1 **Q18. As shown in Table 5, how has the Company determined industry end of life**
2 **expectancy?**

3 A18. The Company's internal subject matter experts draw from a broad set of sources to
4 determine equipment life expectancy, including ongoing review of technical
5 papers, attending industry working groups, meeting with manufacturers, and
6 gaining specific experience with the performance of the assets on the Company's
7 electrical system.

8

9 **Q19. Is age the only factor to consider when selecting assets for replacement?**

10 A19. No. Age is just one of the factors considered when determining asset health and
11 the need for equipment replacement. There are instances where younger equipment
12 is at higher risk of failure, for example due to specific known equipment issues, and
13 is selected for replacement ahead of more aged equipment. Additionally, there are
14 many instances where the Company assesses older equipment and finds that it still
15 can safely and reliably remain in service and serve customers. However, age is a
16 factor used throughout industry as one measure of asset health.

17

18 System Performance

19 **Q20. How does the Company and industry measure system reliability?**

20 A20. The Company uses industry standard reliability metrics that are defined by the
21 Institute of Electrical and Electronics Engineers (IEEE) standard 1366¹. DTE
22 Electric measures overall system reliability using the indices System Average
23 Interruption Duration Index (SAIDI), System Average Interruption Frequency
24 Index (SAIFI), and Customer Average Interruption Duration Index (CAIDI). These

¹ [Microsoft PowerPoint - Without video IEEE 1366- Reliability Indices 2-2019.pptx available at https://site.ieee.org/boston-pes/files/2019/03/IEEE-1366-Reliability-Indices-2-2019.pdf](https://site.ieee.org/boston-pes/files/2019/03/IEEE-1366-Reliability-Indices-2-2019.pdf)

Line
No.

1 indices are typically calculated in two ways: 1) All-Weather conditions, and 2)
2 excluding Major Event Days (MEDs). An MED is any 24-hour period in which
3 there is a significant statistical difference in daily SAIDI. Excluding MEDs from
4 the indices offers a more accurate comparison between time periods and to other
5 utilities because it gives the Company a clear picture of day-to-day system
6 performance and customer experience absent significant weather events – which
7 are highly variable in size, impact, and system location from year-to-year and. The
8 Company’s primary metric for measuring system reliability is the System Average
9 Interruption Duration Index (SAIDI). SAIDI is defined by IEEE as the total time
10 (in minutes) of all customer interruptions divided by the total number of customers
11 served. SAIDI measures the average time that customers are without power in a
12 year because it is calculated using both the frequency and the duration of
13 interruptions. SAIFI is calculated by dividing the number of customer interruptions
14 by the number of customers served. SAIFI measures the average number of
15 sustained interruptions experiences by the system’s average customer. CAIDI is
16 calculated by dividing the sum of customer interruption duration by the total
17 number of customer interruptions. CAIDI measures the average time required to
18 restore power to the average customer who experiences an outage.

19

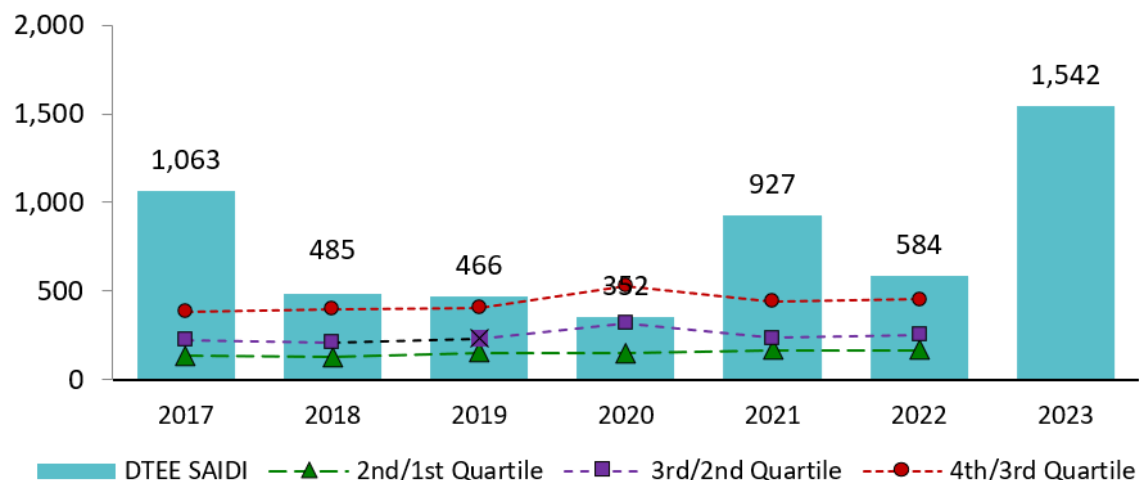
20 **Q21. What are the recent reliability metric trends for the Company’s electrical**
21 **system?**

22 A21. **Figure 2** through **Figure 5** show the distribution system performance from 2017 to
23 2023 for SAIDI-All Weather, SAIDI-Excluding MEDs, SAIFI-All Weather, and
24 SAIFI-Excluding MEDs. As shown in **Figure 2** and **Figure 3**, the Company
25 performed in the 4th quartile in All-Weather SAIDI and 3rd quartile for SAIDI-

Line
No.

Excluding MEDs for 2023. The Company has been, except for 2020, in the fourth quartile for SAIDI-All Weather for the seven years shown on **Figure 2** below. As shown in **Figure 4** and **Figure 5**, the Company performed in the 3rd quartile in All-Weather SAIFI and 2nd quartile for SAIFI-Excluding MEDs for 2023. SAIFI-All Weather has been in the second quartile four of the last seven years. Benchmarking quartiles are not yet available for 2023 so all quartiles referenced for 2023 are compared to the 2022 benchmarking numbers. CAIDI can be calculated by dividing SAIDI by SAIFI. Benchmarking is performed by the Institute of Electrical and Electronics Engineers (IEEE) and made available to its members annually.

Figure 2 All Weather SAIDI Performance*
(Minutes)



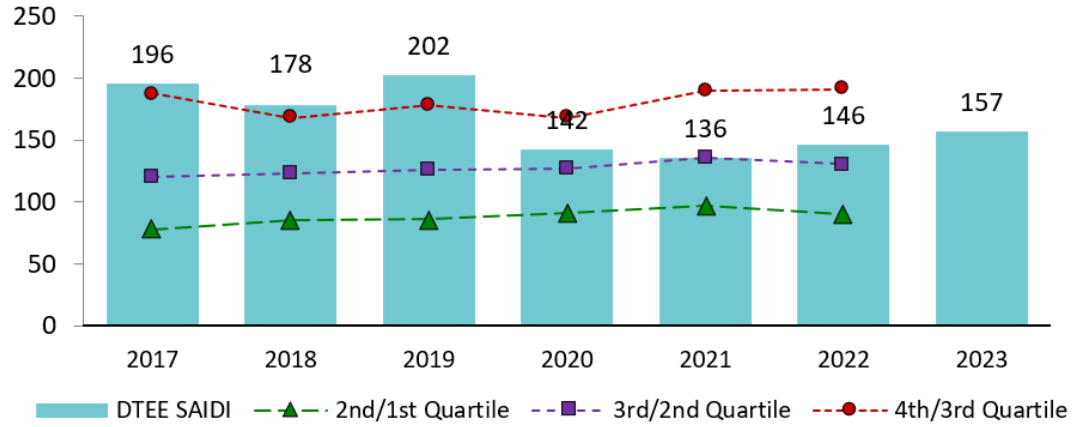
*Quartile information for 2023 is not yet available

Line
No.

1

Figure 3 SAIDI Ex-MED Performance* (Minutes)

2



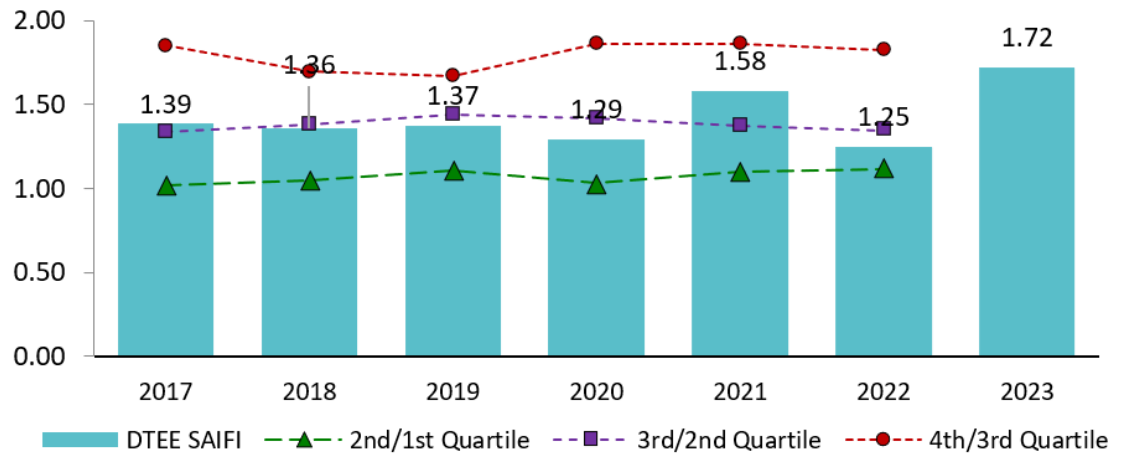
*Quartile information for 2023 is not yet available

3

4

Figure 4 All Weather SAIFI Performance*

5



*Quartile information for 2023 is not yet available

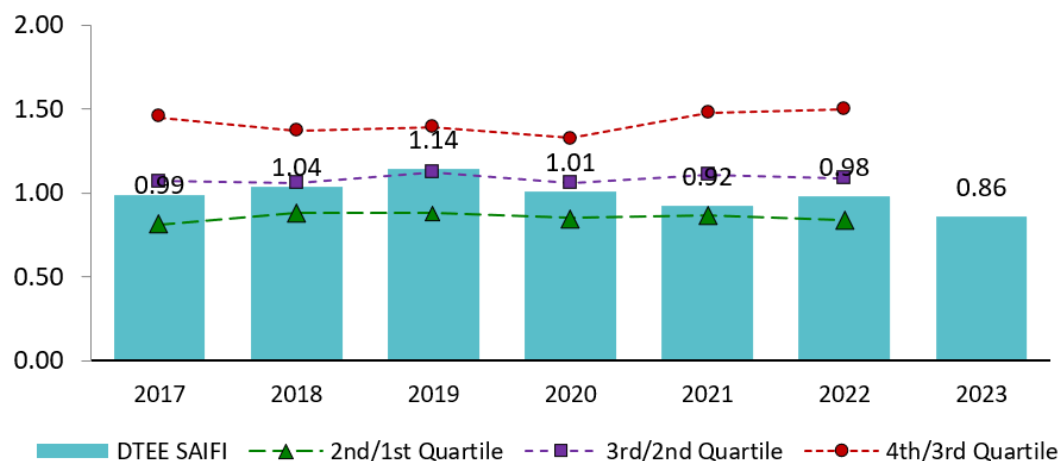
6

Line
No.

1

Figure 5 SAIFI Ex-MED Performance*

2



*Quartile information for 2023 is not yet available

3

4 **Q22. What large weather events impacted the Company's reliability performance**
5 **in 2023?**

6 A22. This past year, 2023, brought additional large storm events including back-to-back
7 storms in February, first ice and then snow, that left over 675,000 customers
8 without power for extended periods of time. These two storms alone contributed
9 730 minutes of All-Weather SAIDI to the annual metric, more than all SAIDI
10 minutes recorded in 2022. However, if the volatility of the extreme weather is
11 removed, SAIFI and SAIDI Excluding MEDs remain in the second quartile
12 indicating that the Company's non-storm performance is stable. See Witness Hill's
13 testimony for additional discussion on 2023 storm impacts.

14

15 **Q23. How have previous strategic investments impacted reliability performance?**

Line
No.

1 A23. Positively. To name a few examples, the Company has seen improved reliability
2 results in areas that have had their Surge Tree Trim program, 4.8kV Hardening, and
3 Frequent Outage Programs. These programs and reliability improvements are
4 discussed in Witness Steudle and Witness Elliott Andahazy's testimony.

5
6 **Q24. What are the primary challenges the Company faces with respect to reliability**
7 **improvements?**

8 A24. There are three primary challenges:

- 9 • First, the Company has seen an increase in the number of high wind speed
10 days which adds additional stress to the already aged fleet of equipment and
11 provides more opportunity for failures (**Figure 6**).
- 12 • Second, the system continues to get older. The average pole age has
13 increased from 40.7 years in 2012 to 47.9 in 2024 – See **Figure 7**. Notably,
14 the slope of the line becomes less steep starting in 2022, indicating the
15 average pole age increased at a slower rate as the Company increased
16 investment in 4.8kV Hardening, PTMM, and 4.8kV Conversion. Continued
17 investments in these programs is needed in order to continue to decrease the
18 rate at which the Company's assets are aging. The pole equipment age curve
19 was selected as a representative sample of the Company's overhead
20 equipment health. DTE will continue to invest in the rebuilding the
21 overhead system to flatten and bend down the age curve.
- 22 • Third, the Company is early on its journey to stabilize and rebuild the grid.
23 While the Company has made progress to date, increased, sustained
24 investment will be needed to improve and then maintain reliability. The
25 Company's 2023 DGP provides a path forward to both improve near-term

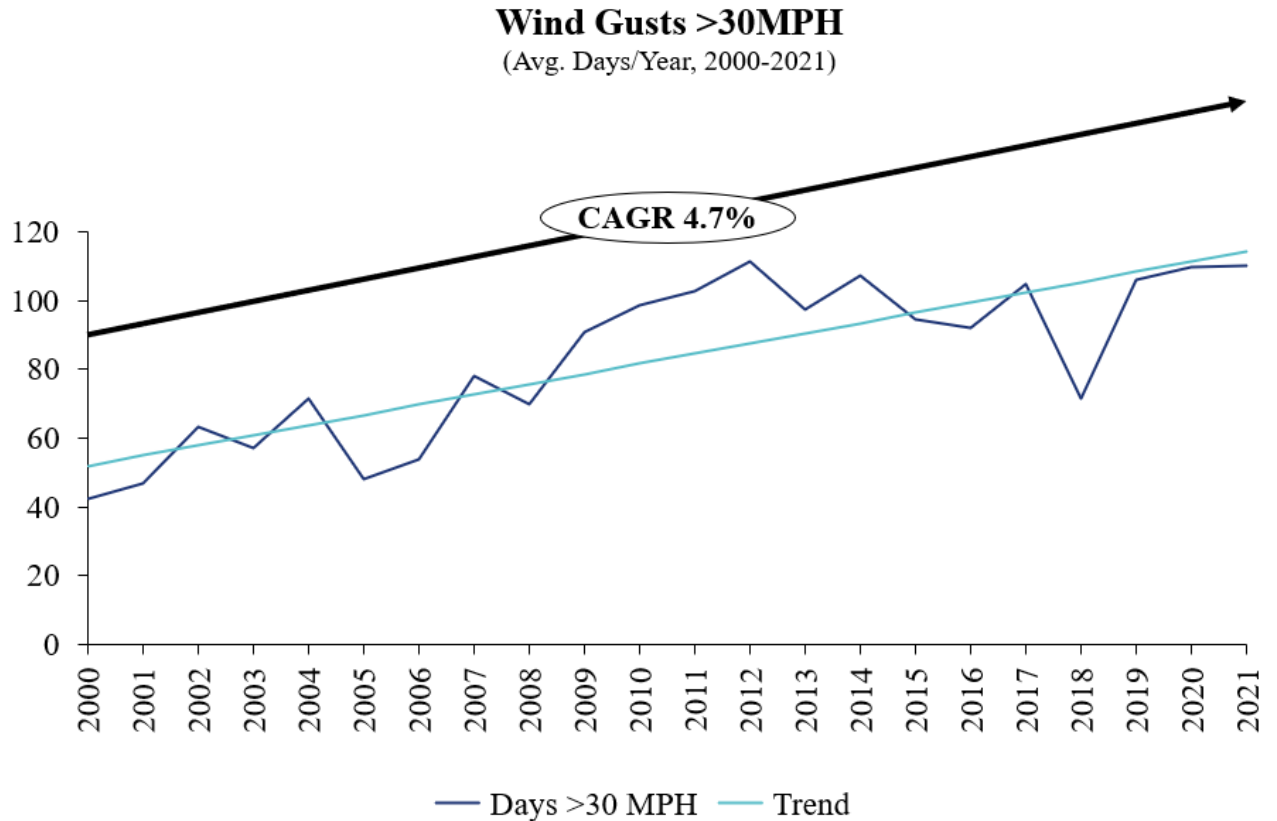
Line
No.

1 reliability and provides a roadmap for the required investment necessary
2 maintain long-term reliability.

3

4

Figure 6 Michigan² Wind Gusts 2000-2021



5

² Data from <https://mesonet.agron.iastate.edu/request/daily.phtml>. SE region represented by Detroit Metro, SW region represented by Ann Arbor, NW region represented by Pontiac.

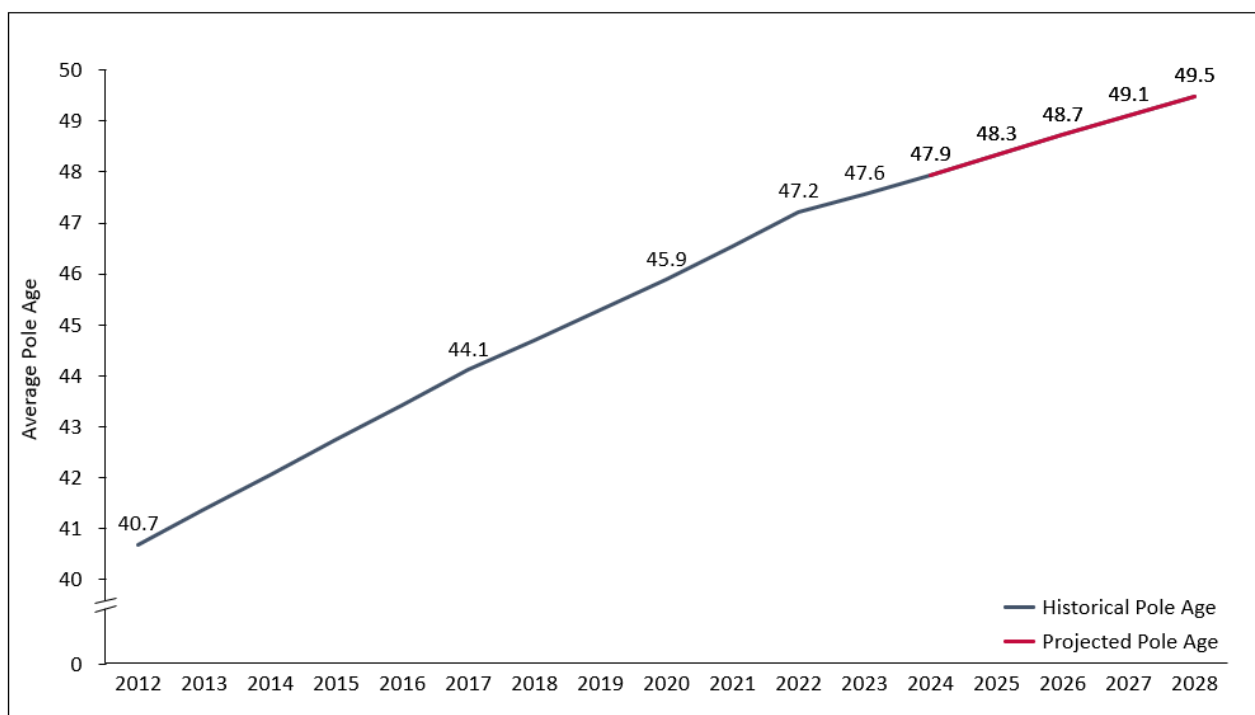
Line
No.

1

Figure 7 Historical and projected average pole

2

age³



3

4

5 **Q25. What changes were made to the Company's investment strategy based on the**
6 **2023 weather events and system age and deterioration?**

7 A25. The Company has increased its investment plans in both PTMM, 4.8kV Hardening
8 and Automation in order to target near and mid-term improvements in fundamental
9 grid resiliency and restoration. Long-term work such as conversions will continue
10 to support rebuilding the grid to increase system resilience and support needed
11 capacity. The Company is also working to improve storm restoration processes,

³ Projected pole age assumes 2025-2028 strategic investment levels for PTMM, 4.8kV Hardening and 4.8kV Conversion are the same as the 2024 investments planned in the case. Poles replaced on base capital, including emergent replacements, are assumed to be constant.

Line
No.

1 including ADMS Enhancements, to be able to respond to storm events more
2 quickly.

3 **Part II: Distribution O&M and Capital Rate Request**

4 **Q26. What O&M and capital is the Company asking the Commission to include in**
5 **rates related to Distribution Operations?**

6 A26. The Company is including \$359.2 million of operation and maintenance (O&M)
7 expenses in the projected test period as shown in Exhibit A-13, Schedule C5.6, Page
8 1, Line 27.

9
10 The Company is requesting \$3.14 billion of capital investments for the 24-month
11 bridge period ending December 31, 2024 and \$1.63 billion of capital investments
12 for the 12-month projected test year ending December 31, 2025, as shown in
13 Exhibit A-12, Schedule B5.4, Page 1, Line 23, supported and sponsored by
14 witnesses Hill, Elliott Andahazy, Hartwick, Deol, and Steudle in base rates.

15

16 **Q27. Why are the levels of capital and O&M proposed by the Company necessary?**

17 A27. The levels of capital investment and O&M expense are necessary to achieve the
18 Company's goals of providing safe, reliable, and clean electricity to our customers
19 at reasonable rates. These investments also lay the foundation for grid
20 modernization, needed to support our customers' evolving needs for greater
21 resiliency in the face of increasingly frequent and intense storms, electrification
22 including electric vehicles (EVs), and the integration of distributed energy
23 resources (DERs).

24

Line
No.

1 **Part III: Distribution O&M Overview and Exhibits**

2 **Q28. What does Exhibit A-13, Schedule C5.6, “Projected Operation and**
3 **Maintenance Expenses – Distribution Expenses” show?**

4 A28. This schedule reflects the operations and maintenance costs for DO, which are
5 primarily driven by systems operations costs (including operating the System
6 Operations Center which monitors and controls the subtransmission and
7 distribution grids), addressing day-to-day trouble and storm restoration, tree
8 trimming, equipment preventative maintenance and other system maintenance
9 requirements. The expenses shown in this exhibit represent both DO and street
10 lighting. Company Witness Bellini provides testimony addressing the streetlighting
11 costs, and Company Witness Steudle supports DO’s tree trimming expenses. I am
12 supporting all other DO expenses.

13

14 **Q29. Can you provide a brief explanation of the items listed under Distribution**
15 **Expenses in Exhibit A-13, Schedule C5.6?**

16 A29. The costs associated with dispatching, coordinating restoration, and tree trim efforts
17 are included in FERC accounts 580 (Operation Supervision and Engineering) and
18 581 (Load Dispatching). Accounts 582 (Station Expenses), 583 (Overhead Line
19 Expenses), 584 (Underground Line Expenses), and 588 (Miscellaneous Expenses)
20 incorporate the costs for developing and implementing training and work force
21 planning for the Company’s substation operators and maintenance personnel,
22 apprentice lineman, splicers, technicians, engineers, riggers, and planners as well
23 as the staff groups to support these critical efforts. Job skills training is conducted
24 for the safety of employees and the public. Witness Bellini supports account 585
25 (Street Lighting and Signal System Expense). Meter testing and distribution costs

Line
No.

1 are incorporated into account 586 (Meter Expenses). Account 587 (Customer
2 Installations Expenses) includes expenses to support the specific needs of
3 customers served at primary voltages. Account 589 (Rents) reflects the expenses
4 associated with leased facilities and the Company attaching to poles not owned by
5 the Company.

6

7 **Q30. What do the line items listed under Maintenance in Exhibit A-13, Schedule**
8 **C5.6 describe?**

9 A30. Maintenance costs are critical to providing safe and reliable service. Account 591
10 (Maintenance of Structures) is to support the maintenance of existing physical
11 structures associated with the electric distribution system. Restoration,
12 troubleshooting and reactive maintenance work associated with substation,
13 overhead and underground equipment is included in accounts 592 (Maintenance of
14 Station Equipment), 593 (Maintenance of Overhead Lines), and 594 (Maintenance
15 of Underground Lines) respectively. In addition, account 593 includes the tree trim
16 expenses supported by Company Witness Steudle. The supervision and other
17 support costs for these important efforts are included in account 590 (Maintenance
18 Supervision and Engineering). Company Witness Bellini supports account 596
19 (Maintenance of Street Lighting and Signal Systems).

20

21 **Q31. How are the 2022 historical O&M and the projected test period O&M**
22 **expenses for DO shown on Exhibit A-13, Schedule C5.6?**

23 A31. Exhibit A-13, Schedule C5.6, page 1, summarizes the 12-month period ended
24 December 31, 2022 actual O&M expense and the projected O&M expense for
25 December 31, 2023 through December 31, 2025. Line 27, column (c) provides the

Line
No.

1 total actual unadjusted O&M expenses for the 12-month historical test period ended
2 December 2022.

3

4 **Q32. What are the adjustments in columns (d) and (e) of Exhibit A-13, Schedule**
5 **C5.6, page 1?**

6 A32. The adjustments in column (d) reduce the total historical test year O&M expenses
7 by the amounts related to the Transitional Reconciliation Mechanism (TRM) costs,
8 which are included in accounts 566 and 588. In column (e) the adjustment on line
9 20 is to normalize restoration expenses, see below. The total results of columns (d)
10 and (e) are added with column (c) to produce column (f).

11

12 **Q33. What are the adjustments in columns (g) through (i) of Exhibit A-13, Schedule**
13 **C5.6, page 1?**

14 A33. The adjustments in columns (g) through (i) show the inflation adjustment to convert
15 the historical test period O&M expenditures to the projected test period dollars. The
16 inflation rates for all DO exhibits are supported by Company witness Uzenski.

17

18 **Q34. What are the adjustments in column (j) of Exhibit A-13, Schedule C5.6, page**
19 **1?**

20 A34. These adjustments are one-time known and measurable adjustments to the
21 Distribution Expenses. The adjustment to Line No. 3, Operation Supervision and
22 Engineering, shows a \$1.6M increase related to the Damage Prevention Program.
23 The adjustment to Line No. 11, Miscellaneous Expenses, shows the cost for the
24 Peaker Study, \$0.3 million, that the Company agreed to complete in the IRP
25 settlement. The adjustment to Line No. 19, Maintenance of Overhead Lines – Tree

Line
No.

1 Trim, shows the \$3.4 million increase in Tree Trim base O&M to remain in line
2 with the funding levels outlined in the Tree Trim Surge plan. The adjustment in line
3 No. 20, Maintenance of Overhead Lines – Other, shows a reduction due to Tree
4 Trim Surge reduction of \$8.8 million offset by inspection expenditures of the Pole
5 and Pole Top Maintenance and Modernization (Pole/PTMM) program and the
6 4.8kV Hardening Program, an increase of \$5.0 million, a net decrease of \$3.8
7 million. The Pole/PTMM program are discussed by Company witness Elliott
8 Andahazy. The adjustment to Line No. 12 is an adjustment to the ADMS regulatory
9 asset supported by Company witness Uzenski.

10

11 **Q35. How did the Company calculate restoration O&M expense for the projected**
12 **period?**

13 A35. As shown on Exhibit A-13, Schedule C5.6, page 2, line 22, column (h), the
14 Company shows projected restoration expenses, including inflation, of \$128.2
15 million. A five-year average method was used to normalize restoration expenses
16 and is consistent with the methodology used in the Company's previous rate cases
17 and the Commission guidance in Case No. U-21297. This method addresses the
18 variability in these expenses.

19

20 The details of this calculation are shown on Exhibit A-13, Schedule C5.6, page 2,
21 "Restoration Expenses". Line 2 shows the actual expenses from 2018 to 2022
22 associated with restoration related to storm conditions. Line 10 presents the actual
23 expenses associated with non-storm restoration. Lines 3 and 11 include inflation
24 adjustments for the historical expenses, and these adjustments are included on lines
25 4 and 12 for storm and non-storm costs respectively. The expenses for the 2018 to

Line
No.

1 2022 period are averaged in column (g) and inflation is applied to those amounts to
2 determine the values in column (j). Column (h) shows the expenses included in the
3 historical test period adjusted for inflation. Column (j) shows the difference
4 between columns (h) and (i). Lines 17 to 22 summarize the calculations and shows
5 on line 22 the \$128.2 million five-year average (column (h)), the \$131.1 million
6 (column (i)) included in the historical test period and the difference of (\$2.9)
7 million (column (j)), which is the adjustment needed in the projected test period for
8 restoration costs in this case. The pre-inflation adjustment of (\$2.6) million
9 included in column (j), line 18 is carried to page 1 of Exhibit A-13, Schedule C5.6
10 in column (e), line 20.

11

12 **Q36. How was the projected O&M expense amount in column (l) of Exhibit A-13,**
13 **Schedule C5.6, page 1, derived?**

14 A36. The 12-month historical test year period ended December 31, 2022 adjusted
15 expenses from column (f) were adjusted by inflation and other expected changes in
16 column (k) to derive projected O&M costs in column (l).

17

18 **Part IV: Distribution Grid Plan (DGP) Overview**

19 **Q37. What is the role of the Distribution Grid Plan (DGP) in supporting the grid**
20 **investments included in this case?**

21 A37. Consistent with Commission guidance on the need for shorter-term investments
22 and longer-term grid planning, the Company filed the updated DGP on September
23 29, 2023, in Case No. U-20147. The 2023 DGP built on the previous DGP filed in
24 September of 2021, also Case No. U-20147 and included an update to DTE
25 Electric's distribution investment strategy considering factors including the

Line
No.

1 continued frequency and intensity of storms, and the aging grid assets. The 2023
2 DGP includes an increased focus on investments that will be able to quickly deliver
3 for customers a safer, more reliable, and more storm resilient grid over the next 5
4 years. In addition, the updated DGP maintains its focus on the Company's 10 to 15-
5 year vision for the grid that includes capacity needed for electrification, and
6 advances in technology to support both reliability and incorporation of Distributed
7 Generation (DG)/Distributed Storage (DS). The DGP supports the development of
8 the investments that are the basis of this case. Furthermore, the direct alignment
9 between the DGP and the investments proposed for rate base treatment illustrate
10 the Company's long-term plans and larger strategy for improving the strength of
11 the distribution system.

12

13 **Q38. Has the Company used previous versions of the DGP to support the**
14 **development of investment plans in previous rate cases?**

15 A38. In two of the Company's recent rate cases (MPSC Case Nos. U-20836, and U-
16 21297), the Company referenced the 2021 DGP filed in September of 2021. In this
17 case the 2023 DGP, along with submitted testimony, supports the Company's
18 distribution investments. The 2023 DGP is included as Exhibit A-23 Schedule M8.
19 The Company's investments as reflected in this case, and in previous cases, are
20 based on long-term distribution planning processes that identify customer and grid
21 needs and develop and prioritize projects that provide both benefits to customers in
22 terms of improved safety and reliability in the near term (primarily achieved
23 through Pole Top Maintenance and Modernization, Automation, and 4.8kV
24 Hardening), and provide the foundation for long-term changes, including increased
25 electrification and Distributed Energy Resource (DER) adoption. The investments

Line
No.

1 in this case are consistent with the long-term vision laid out in the DGP filed in
2 September 2023.

3

4 **Q39. What was the Company's approach to developing the 2023 DGP?**

5 A39. To create the 2023 DGP, DTE Electric followed the five-step methodology used in
6 the development of the 2021 DGP:



7

8 • **Define DTE Objectives:** Reviewed objectives from the Company's previous
9 2021 DGP and aligned them to the long-term distribution grid vision

10 • **Assess Future Drivers of Change:** The future drivers of change that are
11 expected to have a significant impact on the distribution grid over the next five
12 to fifteen years were reviewed, including previously identified scenario
13 signposts.

14 • **Assess Current State:** Assessed the current grid and its capabilities to
15 determine how well it can support current and future customer demands.

16 • **Determine Gaps to Future State:** Identified future state objectives based on
17 future drivers of change, current state assessments and distribution grid gaps.

18 • **Develop Investment Plan:** Based on those gaps, a five-year investment plan
19 was developed, organized within the four pillars of investment. Individual
20 program and project prioritization within the investment plan is done through
21 the Company's Global Prioritization Model (GPM) process – discussed below.

22

Line
No.

1 Additionally, customer and stakeholder feedback were integrated into the Plan,
2 including a shift to consider environmental justice (EJ) in DTE Electric's
3 investment decisions so that projects benefiting our most vulnerable customers are
4 considered in the investment prioritization process.

5 **Q40. How did the Company gather feedback for the most recent DGP?**

6 A40. Feedback was received in several ways including:

- 7 • The March 2023 and August 2023 4.8kV Hardening and DGP Tech
8 Conferences which offered numerous stakeholders an opportunity to
9 provide feedback via roundtable discussions, questions, and written
10 comments.
- 11 • Through the regulatory process associated with Case U-21297, the company
12 received comments and feedback through MPSC Staff and stakeholder
13 testimony.
- 14 • The Commission issued Order and stakeholder comments received in Case
15 No. U-20147 containing feedback on the 2021 DGP.
- 16 • Regular engagement with the Company's customers via community
17 meetings, the DTE customer call center, MPSC complaint response, and
18 other miscellaneous forums.

19

20 **Q41. Please describe how scenario planning informs DGP investments.**

21 A41. Grid modernization plausible scenario planning involves developing scenarios that
22 are directionally correct and plausible. In the context of grid planning, plausible is
23 preferable to using the most likely scenario, in order to analyze impacts that will
24 stress or cause impacts to the grid, and therefore should be reasonably planned for.
25 Plausible scenarios provide input to grid impact of potential future challenges, as

Line
No.

1 opposed to probabilistic or forecasted scenarios. These scenarios focus on a discrete
2 set of drivers and allow for a better understanding of the resulting grid impacts, as
3 well as the potential for overlapping impacts on needed capabilities and the
4 resulting determination of investments. The Company built on the work initially
5 done in the 2021 DGP, to update three scenarios to use for identifying (1) changes
6 coming to the grid in the future, (2) the grid impacts of those potential changes, and
7 (3) the investments needed to mitigate grid impacts. The three plausible future
8 scenarios selected were the Electrification scenario, the Increasing CAT storm
9 scenario, and the DG/DS Scenario (distributed generation [DG] solar photovoltaic
10 [PV] and distributed storage [DS]).

11

12 **Q42. Can you please summarize the key highlights of the DGP?**

13 A42. Using the learnings from scenario planning, combined with an assessment of the
14 current state of the grid, the Company identified gaps between the existing grid and
15 the future state required to meet the DGP objectives.

16

17 Based on this analysis, the 2023 DGP, in line with the 2021 DGP, remains focused
18 on closing these gaps through four investment pillars supporting grid improvement:

19

20 1) Tree Trimming remains focused on completing the Surge plan and returning
21 our electric grid to a routine, maintenance cycle.

22

23 2) Infrastructure Resilience and Hardening projects and programs focus on
24 making the grid more resilient in the face of increasingly severe storms,
25 replacing aging infrastructure at risk of failure, hardening the system, and

Line
No.

1 addressing areas of the system with known poor customer reliability. These
2 projects and programs specifically target equipment with known risks, (e.g.,
3 failed inspections or multiple prior failures), or in areas with known poor
4 customer reliability and potential safety issues, (e.g., high SAIDI or arc wire on
5 the system). Projects in this pillar are designed to provide improved customer
6 reliability and replace at risk equipment quickly. Key areas of focus in this pillar
7 are an expansion in the PTMM program to stabilize the aging overhead
8 equipment as well as finishing the 4.8kV Hardening program which will
9 conclude in 2026 once arc wire is removed. Infrastructure Resilience and
10 Hardening investments are supported by witness Elliott Andahazy.

11

12 3) Infrastructure Redesign and Modernization projects and programs make
13 fundamental improvements to the electrical system, including the conversion of
14 the 4.8kV system and upgrades of the fundamental subtransmission system.
15 Overall redesign and modernization of the system also brings reliability and
16 resilience improvements through the replacement of aging infrastructure.
17 Investments in this pillar provide benefits such as load relief (including
18 increased capacity for electrification) and increased system operability. This
19 pillar focuses on 4.8kV Conversion to rebuild the oldest sections of the grid in
20 orders to accommodate future load growth and boost reliability. The 4.8kV
21 Conversion projects will convert the 4.8kV system to a higher voltage and be
22 built to the latest, most resilient standards, provide higher capacity for
23 electrification, enable DER penetration, and improve safety by eliminating the
24 ungrounded delta configuration and removing arc wire from the city of Detroit.
25 More detail on the 4.8kV conversion is provided is provided in Exhibit A-23

Line
No.

1 Schedule M8 DGP. This pillar also includes subtransmission improvements to
2 add capacity and improve performance of this fundamental part of the grid.
3 Infrastructure Redesign and Modernization investments are supported by
4 witness Deol.

5 4) Technology and Automation projects and programs are focused on ramping up
6 the Company's automation capability and operational Technology (OT)
7 investments that will enable the Company to monitor, control, and optimize the
8 operation of grid. Investments in this pillar focus on the physical infrastructure
9 needed to support a modern distribution grid including reclosers, capacitors and
10 voltage regulation, and grid telecommunications as well as the software and
11 technology needed for operations and improved customer communication.
12 Advanced technology and automation on the grid not only improve customer
13 reliability but is also a key factor in enabling customer accessibility to the grid.
14 Additional investments include the electric system operation center (ESOC)
15 and advanced distribution monitoring system (ADMS), and develop more
16 advanced analytic capabilities. This pillar is an integral part of grid
17 modernization and will allow the Company to develop needed capabilities in
18 grid observability, analytics and computing, grid controls, and communications.
19 Investments in Technology and Automation are supported by witnesses
20 Hartwick and Steudle.

21

22 **Q43. When will the Company file a new DGP?**

23 A43. The Company expects to file another Distribution Grid Plan in 2025 on the normal
24 2-year schedule.

Line
No.

1 **Part V: Strategic Capital Overview**

2 **Q44. How does the Company categorize capital investments?**

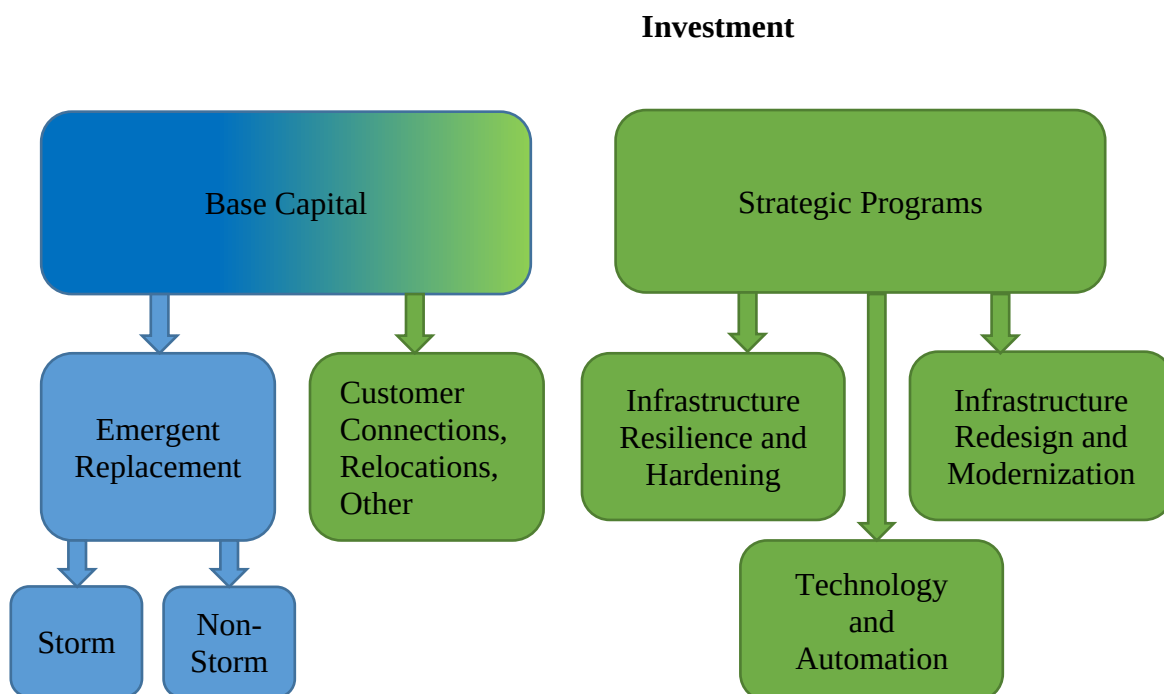
3 A44. Capital investments are broken out into two primary categories: Base Capital and
4 Strategic Capital. Base Capital programs include work the Company is required to
5 perform as part of normal business activities. There are two sub-categories of Base
6 Capital: (1) Emergent Replacements and (2) Customer Connections, Relocations &
7 Other. Emergent Replacements include expenditures to recover from interruptions
8 in electric service (e.g., emergent replacements during storms, equipment failures
9 at substations), address immediate safety concerns, or return the system to normal
10 operating conditions, and are reactive in nature. Customer Connections,
11 Relocations and Other are planned capital expenditures to address customer
12 requests for new or upgraded service connections, or to relocate equipment in
13 response to third-party requests (e.g., Michigan Department of Transportation
14 [MDOT]). Details for Base Capital programs are included in Exhibit A-12,
15 Schedule B5.4, pages 3 to 12, and in more detail on Exhibit A-23, Schedule M4,
16 and are supported by witness Hill.

17
18 The second primary category of capital is Strategic Capital. Strategic Capital
19 projects and programs include work the Company performs to improve safety,
20 reliability and operability, and grid automation and modernization. These
21 investments are subcategorized into three areas or investment pillars: Infrastructure
22 Resilience and Hardening, Infrastructure Redesign and Modernization, and
23 Technology and Automation. Details for Strategic Capital programs are included
24 in Exhibit A-12, Schedule B5.4, pages 13 to 18, and in more detail in Exhibit A-

Line
No.

23, Schedules M-4 through M-7, and are supported by witnesses Hill, Elliott Andahazy, Hartwick, and Deol.

Figure 8 Categories of Planned and Unplanned Capital



*green coloring represents planned capital categories

Q45. Which categories of Capital Investment is the Company able to plan for ahead of time?

A45. In **Figure 8**, the green capital categories are planned: strategic programs and customer connections, relocations and other. The only category of capital for which the Company cannot fully plan is emergent replacements, depicted in blue.

Q46. What level of investment is the Company requesting for capital investments that are for strategic programs or projects in the forward-looking test year ending December 31, 2025?

Line
No.

1 A46. In the projected test year ending December 31, 2025, the Company is proposing to
2 invest a total of \$827.3 million in strategic programs and projects as part of this
3 case (Exhibit A-12 Schedule B5.4 Page 1, Line 22). Additionally, the Commission
4 approved a Distribution Infrastructure Recovery Mechanism (Distribution IRM or
5 IRM) in Case No. U-21297 totaling an additional \$290.1 million in 2025 that is not
6 included in the Company's rate request in this case (Exhibit A-33 Schedule X1
7 Page 1, Line 8) - Witness Foley provides additional information on the IRM in his
8 testimony. Summing both the proposed strategic investment for the 2025 test year
9 and the 2025 IRM yields a total of \$1,117 million of 2025 strategic investment.

10

11 **Q47. What are emergent replacements, and what level of investment is the**
12 **Company requesting for emergent replacements in the test year?**

13 A47. Emergent replacements are those necessitated by damage or failure on the system.
14 Although investments in this category are reactive, rather than proactive, they are
15 essential to restoring customers' power after an outage event, maintain system
16 operability, and in many cases increase reliability. For the projected test year
17 ending December 31, 2025, the Company forecasts \$506.9 million in emergent
18 capital (Exhibit A-12 Schedule B5.4 Page 1, Line 7). Witness Hill discusses
19 emergent replacements in detail in his testimony.

20

21 **Q48. What type of work comprises Customer Connections, Relocations and Other,**
22 **and what level of investment is the Company requesting for Customer**
23 **Connections, Relocations and Other in the test year?**

24 A48. The Customer Connections, Relocations and Other category includes multiple
25 investment areas:

Line
No.

- 1 • Connections and New Load is work required to connect new customer sites
- 2 and load to the distribution system
- 3 • Relocations is work required to move DTE Electric infrastructure primarily
- 4 driven by MDOT and local road commission projects
- 5 • Electric System Equipment is an inventory of critical spare equipment to
- 6 support emergent replacements and planned projects
- 7 • Normal Retirement Unit Change-out (NRUC) and Improvement Blankets
- 8 is work focused on reducing customer outages, replacing end-of-life
- 9 equipment and supporting the AMI platform and data
- 10 • General Plant, Tools & Equipment and Miscellaneous are new replacement
- 11 tools required for field workers to perform their tasks, engineering test
- 12 equipment and substation physical security
- 13 • Public Lighting Department Project is a project to convert Public Lighting
- 14 Department customers to the Company's distribution system

15

16 The Company is requesting \$301 million in Customer Connections, Relocations
17 and Other (Exhibit A-12 Schedule B5.4 Page 1, Lines 15 and 16). Witness Hill
18 discusses the Customer Connections, Relocations and Other category in detail in
19 his testimony.

20

21 **Part VI Capital Exhibits Description**

22 **Q49. How will the Company support the capital investments it is requesting in this**
23 **case?**

24 A49. The Company is supporting the requested capital investments using witness
25 testimony as well as five capital investment exhibits:

Line
No.

- 1 • Exhibit A-12 Schedule B5.4 Projected Capital Expenditures – Distribution
- 2 Plan (witnesses Hill, Elliott Andahazy, Deol, Hartwick and Steudle).
- 3 • Exhibit A-23 Schedule M4 Distribution Plant Capital Project Detail – Base
- 4 Capital (witness Hill).
- 5 • Exhibit A-23 Schedule M5 Distribution Plant Capital Project Detail –
- 6 Infrastructure Resilience and Hardening (witness Elliott Andahazy and Hill).
- 7 • Exhibit A-23 Schedule M6 Distribution Plant Capital Project Detail –
- 8 Infrastructure Redesign and Modernization (witness Deol).
- 9 • Exhibit A-23 Schedule M7 Distribution Plant Capital Project Detail –
- 10 Technology and Automation (witnesses Hartwick and Steudle).

11

12 **Q50. What information is included in Exhibit A-12 Schedule B5.4?**

13 A50. Exhibit A-12 Schedule B5.4 includes the total capital forecast for all of Distribution
14 Operations categories from the historical test period, 2022, through the projected
15 test year 12-months ending December 31, 2025, excluding investments that will be
16 recovered through the Commission approved IRM for the 13 months ending
17 December 31, 2024 and 12 months ending December 31, 2025. Witness Foley
18 covers the IRM in his testimony.

19

20 Page 1 of Exhibit A-12 Schedule B5.4, column (a) includes a brief description of
21 the expenditures included on the line, and column (b) includes the historical (2022)
22 actual investment for each category. Between columns (a) and (b) is a list of
23 footnotes that reference additional details for the investment and forecasting
24 methodologies and witnesses supporting each category. Columns (c) to (e) include
25 forecasts for each line item for 2023, 2024, and the 24-month period ending

Line
No.

1 December 31, 2024, respectively, while column (f) includes forecasts for the 12-
2 month period ending December 31, 2025, the projected test year.

3

4 Page 2 of Exhibit A-12 Schedule B5.4 provides additional detail on the information
5 provided on page 1, showing the normalization adjustments used to reconcile the
6 historical 12 months ended December 31, 2022 to the projected calendar years of
7 2023, 2024 and 2025. Page 2 is structured in much the same way as page 1 with
8 the following exceptions: columns (c) and (d) include adjustments to normalize
9 emergent replacement capital to the five-year average for use in 2024 and 2025
10 forecasts, and columns (e) to (g) provide forecasted investment for 2023, 2024 and
11 2025 respectively.

12

13 Page 3 of Exhibit A-12 Schedule B5.4 provides the calculations of the
14 normalization adjustment applied to emergent capital to reflect a historical five-
15 year average for forecasting less the emergent reduction due to strategic investment
16 and surge tree trim reduction on line 29. More detail on emergent capital
17 expenditures is provided by witness Hill, further detail on the emergent reduction
18 due to strategic investment is discussed in Part IX Capital/Reliability Model and
19 more detail regarding the surge tree trim reduction is sponsored by Witness Steudle.

20

21 Pages 4 through 9 of Exhibit A-12 Schedule B5.4 provide the three-year historical
22 average and projected investments for the Customer Connections, Relocations, and
23 Other subcategories. More detail on these capital expenditures is provided by
24 witness Hill.

Line
No.

1 Pages 10 through 12 provide project lists for the historic test period for New
2 Business and Relocations and are supported by witness Hill.

3
4 Pages 13 through 18 provide the same information as pages 1 and 2 for all the
5 strategic capital projects by category and are supported by various DO witnesses as
6 shown on these pages.

7
8 Page 19 provides detail on the Allowance for Funds Used During Construction
9 (AFUDC) for DO projects and is supported by witnesses Hill, Elliott Andahazy,
10 Deol, and Hartwick. Capital investments include an AFUDC for eligible projects
11 that are in Construction Work in Progress (CWIP) as described by Witness Uzenski.
12 The total DO-related AFUDC is projected to be \$13.8 million for the 12-month
13 period ending December 31, 2025. The authorized overall rate of return used was
14 5.561% per the Order in Case No. U-21297.

15
16 Pages 20 through 26, supported by witnesses Hill, Elliott Andahazy, Deol, Steudle,
17 and Hartwick, provide a breakdown of plant activities, which are used by witness
18 Uzenski to forecast Plant in Service, Accumulated Depreciation and CWIP on the
19 projected balance sheet. Column (a) lists the project and program descriptions listed
20 in the earlier emergent, the customer connections, relocations, and other strategic
21 capital pages. Column (b) includes a corresponding in-service assumption:
22 “Annual” indicates plant investment is generally unitized within the year of
23 investment, while a specific in-service date is used for projects that remain in CWIP
24 for more than a year before moving into Plant in Service. Capital expenditures
25 consistent with page 1 are summarized in columns (c) through (f). Column (g)

Line
No.

1 includes an estimated percentage of removal costs included within the capital
2 expenditures. Removal costs, as discussed by witness Uzenski, are charged to
3 accumulated depreciation rather than Plant/ CWIP and are therefore not
4 depreciable. Removal cost of 15% based on historical trend of removals as a
5 component of capital expenditures is applied to Base Capital Programs,
6 Infrastructure Resilience and Hardening, and Infrastructure Redesign. Technology
7 and Automation projects are assigned 0% since there is no related removal work.
8 Columns (h) through (j) reflect calculated removal costs based on projected Capital
9 Expenditures in columns (d) through (f) multiplied by the removal cost percentage
10 in column (g). The remaining capital expenditures will appear in Plant in Service
11 columns (k) through (m) if the in-service assumption is “Annual”, or CWIP
12 columns (n) through (p) until the date of in-service as indicated in column (b). At
13 the time of in-service (as indicated in column (b)), cumulative investment including
14 the historical period is transferred from CWIP to in-service (excluding the removal
15 cost estimate).

16

17 **Q51. Can you describe what is included in the Exhibit A-23 Schedules M4-M7?**

18 A51. Yes. Exhibit A-23, Schedules M4-M7, supported by witnesses Hill, Elliot
19 Andahazy, Deol, Hartwick and Steudle, provide greater project detail for all
20 projects and programs included in Exhibit A-12, Schedule B5.4, and represents
21 100% of the Company’s total forecast capital for DO. Each document, which can
22 be from one to several pages, includes the following:

- 23 • Program: As described in Exhibit A-12, Schedule B5.4, pages 3 to 18
- 24 column (a).
- 25 • Purpose and Necessity: A description of the driving forces for the work.

Line
No.

- 1 • Category: The pillar of Strategic Capital investment from the DGP or the
- 2 Base Capital investment.
- 3 • Line Number: A reference to the exhibits, schedule, page, and line numbers
- 4 supported.
- 5 • Scope: The scope of work.
- 6 • Benefits: How the Company's customers benefit from the program and a
- 7 description of the how the project or program is expected to impact
- 8 operations and reliability.
- 9 • Impact Dimensions: The GPM dimensions the strategic capital project or
- 10 program will impact. Base capital is excluded from GPM scoring.
- 11 • Approximate Construction Schedule: Proposed work schedule for the rate
- 12 case period.
- 13 • Budget Basis: Origin of budget estimate.
- 14 • Total Estimated Cost: The total expected cost of the project in present
- 15 dollars – this field was added per direction from the Commission (Case No.
- 16 U-21297, p108).
- 17 • Projected: The expected cost of the program for the forecasted years 2023,
- 18 2024, and 2025 in current dollar values.

19

20 **Q52. What is included in the "Other Cost" line item shown in Exhibit A-23**
 21 **Schedules M4-M7?**

22 A52. The other cost line item represents the forecasted amount of overheads that get
 23 applied to a given project/program. Examples of project or program overheads
 24 include facilities, stock, and procurement. Facilities overhead represents the costs
 25 related to preventative maintenance, repairs, and improvements to facilities; these

Line
No.

1 costs are allocated to capital projects based on the amount of direct labor. Stock
2 overhead represents the costs related to operation of warehouses; these costs are
3 allocated to capital projects based on their stock and material purchases.
4 Procurement overhead is the cost related to the supply chain procurement process;
5 these costs are allocated based on the project stock and material purchases,
6 contractor expenditures, and consultant expenditures.

7

8 “Other” costs are allocated to projects based on the mix of direct costs such as labor,
9 material usage, contractor expenditures, etc. “Other” costs for each project/program
10 can vary year to year based on the mix of direct costs. If a project has material
11 purchases scheduled for year one and the labor to install scheduled for year two, it
12 could see more overheads associated with Stock and Procurement for the first year
13 and overheads associated with Facilities in the second year. As the mix of direct
14 costs change year over year, the other costs associated will change as well.

15

16 **Part VII: Capital Investment Variance Discussion**

17 **Q53. What is the purpose of the variance analysis section of your testimony?**

18 A53. To describe variances from forecast in calendar years 2022-2024. The
19 reasonableness and prudence of these expenditures is supported primarily by
20 witnesses Hill, Elliot Andahazy, Hartwick, Deol, and Steudle in their respective
21 testimonies.

22

23 2022 U-21297 Forecast vs. U-21534 Actuals

24

25 **Q54. How does the Company’s 2022 forecast in Case No. U-21297 compare to the**
26 **actual capital investment for 2022?**

Line
No.

1 A54. Exhibit A-23 Schedule M1 Revised compares the 2022 actual capital investment to
2 the Company's capital forecast from Case No. U-21297. Overall, the Company
3 invested \$56.6 million more than forecasted in Case No. U-21297 for calendar year
4 2022, or approximately 4% above the original forecast (Exhibit A-23, Schedule M1
5 Revised, page 1, line 25). The difference is driven by lower than projected base
6 capital of \$13.2 million and increased investments in strategic capital of \$69.8
7 million. Exhibit A-23 Schedule M1 Revised, U-21297 vs. U-25134 2023 Forecast
8 Comparison, provides the project level detail of the variance.

9

10 **Q55. What are the main drivers of the decreased investment in base capital in 2022?**

11 A55. In 2022, the actual investment was \$2.8 million lower than forecast in Emergent
12 Replacements (Exhibit A-23, Schedule M1 Revised, page 1, column c, line 7) and
13 \$10.4 million lower than forecast in Customer Connections, Relocations and Other
14 (Exhibit A-23, Schedule M1 Revised, page 1, column c, line 15) and Customer
15 Advances for Construction (Exhibit A-23, Schedule M1 Revised, page 1, column
16 c, line 16). Lower investment in Emergent Replacements were driven by lower than
17 forecast equipment failure events. The lower investment in Customer Connections,
18 Relocations and Other and Customer Advances for Construction was driven by a
19 lower volume in the number of customer requests.

20

21 **Q56. What are the main drivers of the increased strategic investment in 2022?**

22 A56. In 2022, \$34.3 million of increased investment was in the Infrastructure Resilience
23 and Hardening Pillar. The Company was able to complete more units than
24 forecasted in the Pole and Pole Top Maintenance and Modernization program with
25 \$13.7 million of additional investment and \$6.2 million of additional investment in

Line
No.

1 the 4.8kV Hardening program. Similarly, the Company increased its investment by
2 \$4.5 million in the Frequent Outage Program (CEMI) program by both addressing
3 more circuits and increasing scope on circuits where more work was needed for
4 reliability improvements.

5
6 The Infrastructure Redesign and Modernization Pillar had an increased investment
7 of \$10.3 million primarily driven by accelerating tree trimming work on CODI:
8 Islandview Substation ahead of circuit conversion work as well as progress
9 payments for long lead substation equipment for the 4.8 kV CC: I-94 Substation
10 and Circuit Conversion (Promenade) and System Loading: Richmond/Armada.

11
12 The Technology and Automation Pillar had increased investment of \$25.2 million.
13 The Work Management and Scheduling Upgrades project had additional
14 investment of \$6.0 million for new tools supporting field and storm processes. For
15 the Grid Automation Telecommunications as well as NWA: Omega Load Relief,
16 both projects pulled ahead \$4.4 million of material and equipment purchases to
17 avoid supply chain delays. The “Other Modernize Grid Management project” had
18 an additional \$3.0 million in investment driven by Error Free Communications
19 interface work and field network end of life equipment replacement. For the Tree
20 Trim Risk Prioritization Model, the total investment was shown in Exhibit A-12,
21 Schedule B5.7.7, page 1, line 25 in Case No. U-21297. When the project was
22 implemented, the investment was split into two locations in this case. The \$6.4 IT
23 investment shows on Exhibit A-12, Schedule B5.7.7, page 1, line 39 and \$3.1
24 million of investment shows on Exhibit A-12, Schedule B5.4, page 17, line 24. This
25 split results in a \$3.1 million increase investment in the Technology and

Line
No.

1 Automation Pillar. For the Interconnection Process Enablement project, the
2 interconnection gateway platform development was pulled ahead leading to \$2.8
3 million of increased investment. An additional \$5.9 million of investment was
4 made across other projects as shown in exhibit A-23, schedule M1 Revised.

5
6 These expenditures facilitated necessary system upgrades or improvements to
7 continue safe and reliable service to customers and were reasonably and prudently
8 incurred.

9

10 **Q57. How did actual capital investments for 2022 compare to rates included in the**
11 **Commission's final Order for Case No. U-21297?**

12 A57. Distribution Operations' actual capital investments equaled \$1,496.1 million in
13 2022. In the rate order, distribution plant investments of \$1,434.3 million were
14 included in rate base, or \$61.8 million less than the actual prudently incurred
15 investments (see witness Uzenski's Exhibit A-12, Schedule B5, line 7).

16

17 2023 U-21297 Forecast vs. U-21534 Forecast

18

19 **Q58. How does the Company's 2023 forecast in MPSC Case No. U-21297 compare**
20 **to the forecast in this case?**

21 A58. Exhibit A-23 Schedule M2 Revised compares the 2023 forecast capital investment
22 Case No. U-21297 to this case. Overall, the Company is projecting to invest \$129.4
23 million more than forecasted in Case No. U-21297 for calendar year 2023,
24 approximately 9% above the original forecast. The difference is driven by higher
25 than projected base capital of \$139.9 million and lower strategic capital investments

Line
No.

1 of \$10.5 million. Exhibit A-23 Schedule M2 Revised, U-21297 vs. U-25134 2023
2 Forecast Comparison, provides the project level detail of the variance.

3

4 **Q59. What are the main drivers for the 2023 base capital forecast changes?**

5 A59. The primary changes in the 2023 base capital forecast changes are driven by storms.
6 2023 included five (5) catastrophic storms, including the most damaging winter ice
7 storm in Company history, and another summer catastrophic storm event that
8 included heavy damage from historic six tornadoes. See witness Hill's testimony
9 for discussion on base capital.

10

11 **Q60. What are the main drivers for the 2023 strategic capital forecast changes?**

12 A60. For 2023, the Company is projecting \$42.4 million of increased investment in the
13 Infrastructure Resilience and Hardening Pillar, \$29.0 million of increased
14 investment in the Technology and Automation Pillar, and \$81.9 million of
15 decreased investment in the Infrastructure Redesign and Modernization Pillar.
16 Overall, the Company is forecasting \$10.5 million of decreased investment in
17 strategic capital.

18

19 2024 U-21297 Forecast vs. U-21534 Forecast

20

21 **Q61. How does the Company's 2024 forecast in MPSC Case No. U-21297 compare**
22 **to the forecast in this case?**

23 A61. Exhibit A-23 Schedule M3 Revised compares the 2024 forecast capital investment
24 Case No. U-21297 to this case. Overall, the Company is projecting to invest \$59.8
25 million less than forecasted in Case No. U-21297 for calendar year 2024, or
26 approximately 4% less the original forecast. The difference is driven by higher

Line
No.

1 than projected base capital of \$111.0 million and lower strategic capital investments
2 of \$170.8 million. Exhibit A-23 Schedule M3 Revised, U-21297 vs. U-25134 2024
3 Forecast Comparison, provides the project level detail of the variance.
4

5 **Q62. What are the main drivers for the 2024 base capital forecast changes?**

6 A62. Emergent replacements are forecast based upon a five-year historical average as
7 discussed in Witness Hill's testimony. In this case, per the approved methodology,
8 the five-year average calculation replaced 2017, a lower cost year, with 2022, a
9 higher cost year. This change increased the projection, resulting in an additional
10 \$69.2 million in the 2024 forecast for emergent replacement (Exhibit A-23,
11 Schedule M3 Revised, column d, line 7). This increase in Emergent Replacement
12 did not impact the Company's strategic capital investment level. For Customer
13 Connections, Relocations and Other, the I-375 relocation project is a primary driver
14 of increased investment with \$25 million projected in 2024. The other cost drivers
15 that make up the full \$111.0 million are found in Exhibit A-23 Schedule M3
16 Revised, U-21297 vs. U-25134 2024 Forecast Comparison.
17

18 **Q63. What are the main drivers for the 2024 strategic capital forecast changes?**

19 A63. In Case No. U-21297 the Company forecasted total strategic capital at \$879.6
20 million for the calendar year 2024. In this case the Company is forecasting a total
21 strategic capital investment of \$708.8 million, a decrease of \$170.8 million from
22 the U-21297 forecast. Of the \$170.8 million decrease, \$60.6 million is a simple
23 shift of investment to the IRM. Project and Program investment changes were based
24 on the Company's review of strategic factors since the initial Case No. U-21297
25 filling including 2023 ice storm learnings (increased focus on near term reliability

Line
No.

1 such as 4.8kV Hardening, and Automation) and the December Case No. U-21297
2 rate order. The Commission approved an annual investment level of \$659.4 million
3 in strategic investment in the Case No. U-21297 order, a difference of \$220.1
4 million from what the Company originally forecasted.

5
6 In the Infrastructure Resilience and Hardening Pillar, the Company is forecasting
7 an increase of \$56.6 million, primarily driven by an \$80.0 million increase in the
8 4.8kV Hardening program, carryover work for Substation Risk: McGraw of \$37.8
9 million, an offsetting decrease of \$57.1 million in PTMM due to rate order
10 guidance, and other miscellaneous adjustments that result in an additional \$4.1M
11 reduction. The Company is forecasting an increased investment of \$24.4 million in
12 the Technology and Automation Pillar for operational technology projects initiated
13 to support and enhance storm restoration efforts. In the Redesign and
14 Modernization Pillar, the Company is forecasting a decrease of \$251.7 driven by
15 shifting \$60.6 million of investments to the IRM and \$191.2 million of project
16 investment to later years, in part, to shift investment to projects that impact near
17 term system resiliency, including Automation and Hardening.

18

19 Capability to Execute Strategic Work

20

21 **Q64. How does the Company ensure that it has the capabilities and resources**
22 **required to make its proposed strategic investments?**

23 A64. As the long-term needs of the electric grid call for increasing levels of investment,
24 the Company has responded by increasing our labor force (employees and
25 contractors, engineering and planning staff), leveraging partnerships, and
26 strengthening project management and supply chain oversight. The Company has

Line
No.

1 instituted workforce planning processes and tools that calculate overall resource
2 demands for all field trades, as well as support and enabling groups including
3 engineering, designers, and project managers. Estimates and forecasts for short-
4 term and long-term resource needs are performed on an ongoing basis as an input
5 to our sourcing decisions. DTE Electric will add staffing as needed to address our
6 growing capital investment portfolio.

7

8 The projected resources (Company and contractors) required by year-end 2023 to
9 complete the planned strategic capital investments is just over 5,200 full-time
10 equivalents (FTEs). The projected resources (Company and contractors) required
11 by year-end 2024 to complete the planned strategic capital investments is
12 approximately 5,500 FTEs. As a result, the Company currently has more line
13 workers in the field than ever before. Additionally, the Company utilizes strategic
14 partnerships with engineering and design firms and front-line labor contractors.
15 Local contractor workforce has been growing as our investments have increased.
16 Contractor needs that exceed the local workforce availability and are supplemented
17 with additional work force from outside of the area.

18

19 As discussed above, the Company has a Project Management Organization (PMO)
20 specifically focused on managing this growing work force. Additionally, the PMO
21 works with the Company Supply Chain Management team to mitigate impacts of
22 material supply chain challenges. These mitigation actions include, but are not
23 limited to:

24

Line
No.

- 1) Increasing the number of suppliers for key equipment including transformers, insulators, and cross arms.
- 2) Demand planning with a long-time horizon, including securing product slots for current year and beyond with suppliers.
- 3) Deploying weekly and daily tracking calls with key suppliers (driving collaboration and leveraging our resources, including transportation, to keep orders on track).
- 4) Sending supply chain and other employees to supplier facilities to provide real time governance and quality control on purchased materials.

10

11 The Company continues to grow its strategic capital capabilities with over \$700
12 million invested in 2022 and over \$800M invested in 2023.

13

14 **Part VIII: Global Prioritization Model**

15 **Q65. What is the Global Prioritization Model (GPM) and how does it support the**
16 **prioritization of capital strategic investments?**

17 A65. The GPM is a tool the Company's Distribution Operations team developed to
18 prioritize investments by ranking projects and programs based on the benefits the
19 project or program delivers for a given level of investment. The ranking is
20 accomplished through a process of evaluating a project across ten impact
21 dimensions, which represent project benefits, and developing a total project score
22 based on the weighting of each impact dimensions. The model results serve as the
23 initial basis for the Company's investment prioritization and highlight those
24 projects that have the highest relative benefit and/or are most urgent.

25

Line
No.

1 **Q66. Does the GPM consider benefits and costs?**

2 A66. Yes. Each of the ten impact dimensions within the GPM measures a benefit of the
3 project or program. These benefits are weighed against costs in eight of the
4 dimensions. Costs are not considered when evaluating if the project or program
5 delivers benefits in the “Regulatory Compliance” or “Investment in EJ
6 communities” dimensions.

7
8 **Q67. Does the GPM determine if benefits exceed costs?**

9 A67. No. In order to determine if benefits exceed costs, all benefits would need to be
10 translated into a monetary value. Only two of the benefits the GPM captures, O&M
11 Avoidance and Capital Avoidance, are measured in monetary terms. All other
12 dimensions are quantified in non-monetary terms. While the GPM does not
13 determine if benefits exceed costs, it does utilize benefit-cost ratios in most of its
14 dimensions to provide a result where projects which deliver the most benefits per
15 dollar invested receive the highest scores. Not all dimensions use this structure,
16 specifically “Regulatory Compliance” and “Investment in EJ Communities”, where
17 programs receive a score without dividing by overall project cost.

18
19 **Q68. Why doesn’t the Company convert all project benefits to a monetary value?**

20 A68. The non-monetary benefits which the GPM measures have no standard or generally
21 accepted method available to convert the quantified benefits into a monetary value.
22 While SAIDI and SAIFI can be monetized relative to the customer potential cost
23 impacts of an outage by using the ICE calculator developed by Lawrence Berkeley
24 National Laboratory (LBNL), that methodology has limitations including dated
25 customer survey data. Other benefits such as providing load relief so that equipment

Line
No.

1 does not operate over its designed rating, or reducing the probability of major
2 events, or investing in EJ communities do not have any commonly accepted
3 conversion to a monetary value. Additionally, the Company does not place a
4 monetary value on project benefits which deliver safety benefits such as a reduction
5 in energized wire-downs. Using the Current GPM methodology, the Company can
6 transparently demonstrate which projects provide the highest benefit for customers
7 across different impact dimensions.

8

9 **Q69. What determines whether a project is scored in the GPM?**

10 A69. The engineering team evaluates alternatives to meet the system needs and selects
11 the best project or program to move forward. If necessary, a BCA takes place as
12 part of the engineering process to select the best option. The solution which is
13 selected to move forward is scored in the GPM for prioritization.

14

15 **Q70. Has the GPM model been recently updated?**

16 A70. Yes. As introduced in the 2023 DGP filing the GPM has been updated to include
17 three new dimensions to capture additional project benefits and to align to two
18 additional planning objectives (Clean, and Customer Accessibility and Community
19 Focus). Specifically, the dimension of “Investment in EJ communities” was added
20 based on feedback from the Commission to incorporate equity into the decision-
21 making process.⁴ Additionally, the weightings of each dimension have been
22 updated. The “Investment in EJ communities” addresses the Commission’s order
23 in Case No. U-20836: “the Commission will continue to hold DTE Electric to its

⁴ See Commission’s Order on November 18, 2022 in docket U-20836 (p 459).

Line
No.

1 commitments to more fully incorporate equity considerations into its decision-
2 making processes”.

3 **Q71. How does the GPM consider DTE Electric's planning objectives when**
4 **evaluating the Company's distribution investment options?**

5 A71. The Company uses the GPM to assess the benefits that strategic investments have
6 on the distribution system as they relate to each of five planning objectives of 1)
7 Safe, 2) Reliable and Resilient, 3) Affordable, 4) Clean, and 5) Customer
8 Accessibility and Community Focus. All impact dimensions that are measured in
9 the GPM are aligned to one or more of these five planning objectives as described
10 in **Table 6**. These five objectives also align with the Commission’s overarching
11 objectives for the electric distribution system, which are safety, reliability and
12 resilience, cost effectiveness and affordability, and accessibility.⁵

13

14 **Table 6 Mapping of GPM impact dimensions to Planning Objectives**

15

		Planning Objectives				
		Safe	Reliable and Resilient	Affordable	Clean	Customer accessible and community focus
GPM Impact Dimensions	Reduce Electrical Hazards	✓		✓		
	Overload Relief	✓	✓	✓	✓	✓
	SAIDI	✓	✓	✓		
	SAIFI		✓			
	Regulatory Compliance	✓	✓			
	Major event risk	✓	✓	✓		
	Capacity Relief		✓		✓	✓
	Investment in EJ communities					✓
	O&M Avoidance			✓		
	Capital Avoidance			✓		

16

⁵ See Commission’s Order on October 11, 2017 in docket U-18014 (pp10-12) and re-affirmed in the Commission Order on August 20, 2020 in docket U-20147 (pp 36-38).

Line
No.

1 **Q72. What impact dimensions are quantitatively assessed to determine project and**
2 **program impact across the Company’s Planning Objectives?**

3 A72. In the GPM, strategic investments are evaluated against ten impact dimensions as
4 described in **Table 7**. Quantitative assessments are conducted for all the impact
5 dimensions to score and rank investments.

6

7 **Q73. What impact dimensions have remained unchanged in the updated GPM?**

8 A73. Six of the Seven original impact dimension have calculations that remain
9 unchanged. Four impact dimensions, Regulatory Compliance, Major event risk,
10 O&M Avoidance, and Capital Avoidance, are unchanged from the previous GPM.
11 Two additional dimensions have been renamed but the calculations are the same as
12 in the previous GPM. The “Reduce electrical hazards” dimension was previously
13 named “Safety” and “SAIDI” was previously named “Reliability”.

14

15 **Q74. What impact dimensions were added or changed in the updated version of the**
16 **GPM?**

17 A74. Two dimensions were added, and one dimension was divided into two separate
18 dimensions. The two new dimensions are “SAIFI” and “Investment in EJ
19 communities”. To better differentiate day-to-day loading challenges from
20 constraints that limit operational flexibility, the “Load Relief” dimension in the
21 previous iteration of the GPM has been split into two dimensions: “Overload Relief”
22 and “Capacity Relief”.

23

24 **Q75. Was the weighting of dimensions changed in the updated version of the GPM?**

Line
No.

- 1 A75. Yes, the weighting of the dimensions was simplified from a ten-point scale to a
2 three-point scale.

3 **Table 7 Global Prioritization Model Impact Dimensions**

4

Impact Dimension	Drivers	Weight
Reduce Electrical Hazards	- Reduction in wire down events - Reduction in secondary network cable manhole events	3
Overload Relief	Elimination of overloaded equipment	
SAIDI	Reduction in duration of outage events	
SAIFI	Reduction in frequency of outage events	
Regulatory Compliance	- MPSC staff's recommendation (March 30, 2010, report) on utilities' pole inspection program - Docket U-12270 – Service restoration under normal conditions within 8 hours - Docket U-12270 – Service restoration under catastrophic conditions within 60 hours - Docket U-12270 – Service restoration under all conditions within 36 hours - Docket U-12270 – Same circuit repetitive interruption of fewer than five within a 12-month period	2
Major Event Risk	Reduction in extensive substation outage events that lead to a large amount of stranded load for more than 24 hours	
Capacity Relief	Elimination of system capacity constraints	
Investment in EJ Communities	Percent of customers impacted by investment in EJ communities	
O&M Avoidance	- Trouble event reduction and truck roll reduction - Preventive maintenance investment reduction	1
Capital Avoidance	- Trouble event reduction and truck roll reduction - Reduction in capital replacement either during equipment failures or avoided planned capital work	

Line
No.

1 **Q76. What are the drivers of the changes to the GPM?**

2 A76. The GPM was changed to capture customer benefits that were not previously
3 accounted for, and to include benefits from across all of DTE Electric’s Planning
4 Objectives (as shown in **Table 6**). “SAIFI” was added because reducing frequency
5 of outages is important to providing reliable power to our customers, and because
6 the State’s Reliability and Service Quality standards provide guidance on what
7 outage frequency is consistent with an acceptable level of service. Project benefits
8 in the “Capacity Relief” dimension were added to measure projected load
9 constraints in 2035, and to account for benefits accrued by addressing circuits that
10 do not have enough capacity to fully realize automation capabilities. Incorporating
11 the 2035 load projection aligns with the Company’s goals to provide a grid that
12 facilitates a transition to a decarbonized economy. “Overload Relief” accounts for
13 benefits that come from reduced day-to-day equipment loading. Finally, by adding
14 the “Investment in EJ communities” dimension, which scores a project based on
15 the percentage of customers benefiting from this project who are from EJ
16 communities, we have incorporated equity into our planning and capital
17 prioritization process as directed by the Commission in 2022.⁶

18

19 **Q77. How are projects ranked using the GPM?**

20 A77. Strategic investments are assessed, scored, and then ranked in a quantitative manner
21 on how they support/improve each impact dimension. **Table 8** shows the mapping
22 of the investments to the impact dimensions they general receive a score in, based
23 on the benefits the investment delivers.

24

⁶ See Commission’s Order on November 18, 2022 in docket U-20836 (p 459).

Line
No.

1

Table 8 Selected programs and GPM impact dimensions

2

Program	Impact Dimensions									
	Reduce Electrical Hazards	Overload Relief	SAIDI	SAIFI	Regulatory Compliance	Major Event Risk	Capacity Relief	Investment in EJ Communities	O&M Avoidance	Capital Avoidance
Substation Risk						X		*		
4.8kV Hardening	X		X	X				X	X	X
PTMM	X		X	X	X			P	X	X
Cable Replacement						X		P		X
Frequent Outage			X	X	X			P		
Breaker Replacement			X	X		X		P	X	X
URD Replacement			X	X				P		X
<u>Subtransmission Redesign</u>		X					X	*		
CODI	X	X	X	X		X		*	X	X
4.8kV Conversion	X	X	X	X		X		*	X	X
System Loading		X	X	X		X	X	*	X	X
Automation	X		X	X				P		

Investment in EJ Community Key: * = Dependent on location of project, X = Yes, addresses EJ communities, P = program where some areas of the program will occur in EJ communities

3

4

Detailed analyses based on historical data, engineering assessments, and field feedback was used to quantify each investment's benefits within each impact dimension. The quantified benefits were then compared to the investment's costs to derive benefit-cost ratios used to determine the relative difference between projects.

9

10

Unit measurements used for benefit-cost ratios are different for each impact dimension. For example, reliability benefits are captured in customer minutes of interruption reduction whereas O&M and reactive capital benefits are captured in dollars avoided.

13

Line
No.

1 Each program's benefit-cost score for each impact dimension is indexed so that a
2 project with a benefit-cost ratio at the 95th percentile receives a score of 100.
3 Projects scoring exceptionally high, above the 95th percentile, will receive a score
4 above 100. This method provides three benefits. First, by aligning the 95th
5 percentile to a score of 100, outlier projects do not skew the entire index. Second,
6 the 100-point scale makes it makes it easy to understand which projects are
7 delivering the highest benefit per dollar invested – namely, the ones which score
8 closer to 100. Finally, indexing, along with the weighting of dimensions, allows for
9 the consideration of multiple monetary and non-monetary benefits to be combined
10 into a single analysis.

11

12 Impact dimensions are weighted relative to each other. **Table 7** lists the different
13 weights given to each impact dimension. The weights of each dimension were
14 simplified in the recent GPM update from a 10 point range to a 3 point range
15 Dimensions which align with core safety and reliability improvements, such as
16 Reduce Electric Hazards, one of the Company's most important impact dimensions,
17 is given the highest weight of 3. This change effectively means that a score of 100
18 in a lower weighted dimension will not be worth as much as a 100 rating in Reduce
19 Electrical Hazards. For example, if a project's Reduce Electrical Hazards score is
20 50 (on a 0-100 scale), it will be multiplied by a weighting factor of 3 to receive a
21 score of 150. A project with a Capacity Expansion score of 50 will be multiplied
22 by the weighting of 2 and contribute 100 to the total scoring. This example
23 illustrates how the impact dimension weights will rank projects higher if they
24 provide benefits in dimensions which have higher weightings. Once a program's
25 index scores have been calculated across all impact dimensions and adjusted by

Line
No.

1 weighting, the index scores are summed together to determine the program's
2 overall score. The higher the score, the better the GPM ranking.

3

4 **Q78. How do the GPM results influence the Company's distribution investment**
5 **decisions?**

6 A78. We use the GPM to pick the highest relative benefit projects that will have the
7 greatest impact improving the grid and the overall customer experience. Projects
8 and programs are ranked using the GPM on an annual basis. Investments that score
9 highest in the GPM rankings are generally selected for the Company's distribution
10 infrastructure strategic investment plan. As described in detail below, there are
11 some projects that are chosen outside of the GPM process or lower ranked projects
12 within the process that are funded for various operational reasons.

13

14 Projects and programs that span multiple years are evaluated every year and may
15 experience a change in GPM ranking if additional information changes the expected
16 project costs or benefits. However, to keep scoring relatively consistent year over
17 year, the entire project cost and entire project benefits are still used when scoring
18 the project or program – although the project costs and benefits will be adjusted for
19 known changes (examples include costs increases or more benefits than forecast).

20

21 **Q79. How does the GPM support reasonable and prudent prioritization of**
22 **investments?**

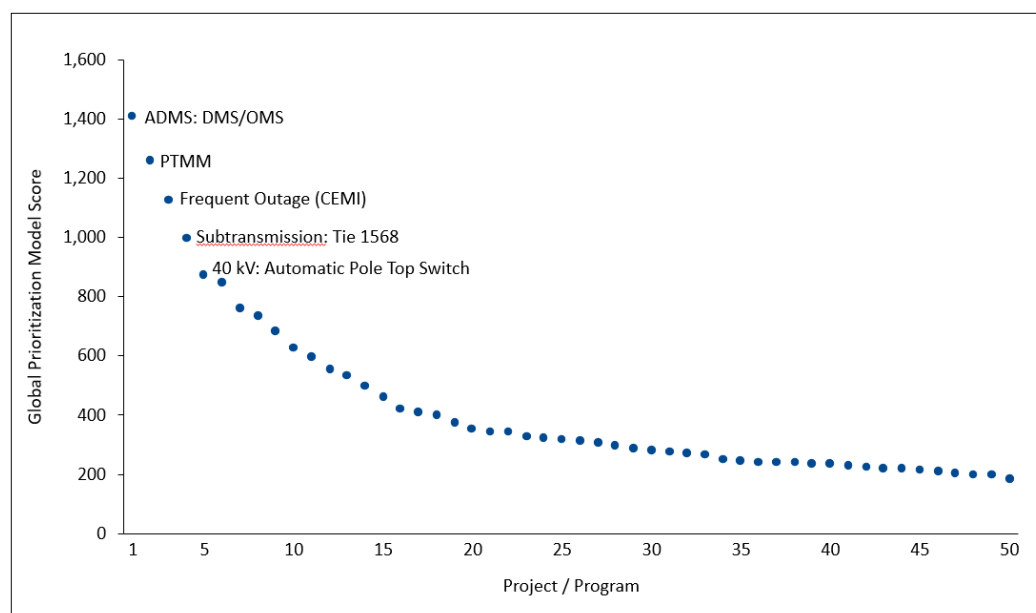
23 A79. The GPM helps the Company compare hundreds of vastly different types of
24 projects and programs of different sizes and identify which ones are going to be the
25 most beneficial for customers.

Line
No.

1 **Q80. What are the GPM scores for the projects and programs proposed in this case?**

2 A80. The total GPM scores for strategic capital projects and programs, ranked from
3 highest to lowest, is illustrated in **Figure 9. Table 9** lists the names of the capital
4 projects and programs ranked in the top 50. GPM scores for the top 50 projects and
5 programs including scores for each of the 10 impact dimensions is included in
6 Exhibit A-23 M14 GPM Project and Program Rankings. Tree trimming⁷ to the
7 enhanced specification, although excluded from the **Table 9** and **Figure 9**,
8 continues to provide high customer benefits, and ranks within the top five projects
9 and programs in the Company's five-year investment portfolio.

10 **Figure 9 Overall Benefit-Cost Scores for top 50 strategic capital**
11 **programs and projects**



12

⁷ Tree trimming, as an O&M program, is excluded from the **Figure 9** and **Table 9**. Nonetheless, tree trimming to the enhanced specification has a top 5 benefit-cost ranking among all programs.

- 1
- 2

3

4

5

Line
No.

1 A81. Yes. While the benefit-cost scores of programs and projects and their prioritization
2 ranking provide the foundation for the Company's strategic investment decisions,
3 there are other considerations that impact project selection and timing, as listed
4 below:

5

6 • Investment timing for programs and projects considers the impact on
7 workforce needs. Resources required for engineering, design, project
8 management, scheduling, and construction need to be evaluated not only by
9 project type (substation, overhead or underground) but also by geographic
10 location. Resource gaps and balancing are evaluated before project
11 sequencing decisions are made. Funding decisions also consider the
12 Company's capacity to perform the work, as the Company often partners
13 with third parties to plan and execute projects.

14 • System operational constraints and stability, occasionally including
15 transmission, can cause the Company to pull a project ahead. For example,
16 a project may be needed to address subtransmission system integrity caused
17 by load growth.

18 • Regulatory requirements or guidance also influence the selection of some
19 projects and programs regardless of the GPM ranking. NERC requirements,
20 for example, require upgrades to ensure the bulk electric system is
21 unaffected by subtransmission outages. These NERC driven projects have
22 benefits that are difficult to quantify in GPM.

23 • Safety issues that cannot be easily quantified and indexed could warrant an
24 investment outside of the GPM model to protect our customers or

Line
No.

1 employees. For instance, subtransmission disconnect switches and the
2 Pontiac vault projects are necessary to meet operational safety needs.

3 • Pilot projects are excluded from the ranking process as they are used to
4 determine what the true benefits and cost will be to complete an activity that
5 the Company believes will be beneficial to its customers. In other words,
6 the pilots help provide the data for a more adequate accounting of future
7 project benefits. An example is non-wire alternative (NWA) projects. These
8 NWA pilot projects focus on using alternative technologies to address circuit
9 or substation overload concerns to help delay or offset traditional grid
10 upgrades. The Company developed these NWA pilots to better understand
11 the customer and costs benefits as part of the longer-term grid modernization
12 plan, so that in the future these can be evaluated against more traditional
13 alternatives. These pilots are supported by Company witness Hartwick and
14 detail is provided in Exhibit A-12 Schedule B5.4.1 through B5.4.7 and
15 B5.4.9.

16 • Capital projects are subject to development milestones, especially in the
17 conceptual design and early development stages, including land availability
18 and property purchases, municipal approvals and construction permits, right-
19 of-way acquisition and easements, and lead times when procuring major
20 equipment. While the Company takes proactive measures to mitigate these
21 execution risks, many of these early-stage milestones are difficult for the
22 Company to control and can introduce schedule delays or cost increases.
23 Therefore, the Company's investment and maintenance plan is designed to
24 include some flexibility to accommodate these unpredictable variations in
25 timing and cost.

Line
No.

- 1 • Some capital replacement programs are funded annually, to avoid
- 2 acceleration of asset failures and the risk that a large quantity of assets would
- 3 reach end-of-life concurrently, thus exceeding available resources to replace
- 4 them (e.g., underground residential distribution cable program).
- 5 • If the Company is awarded grant money from the state or federal government
- 6 for specific projects, including IJJA grants, it could positively impact project
- 7 selection due to grant project completion requirements. In 2023, the
- 8 Company was awarded an Adaptive Networked Microgrids (ANMs) grant
- 9 which the Company has funded in both 2024 and 2025. This project is further
- 10 discussed by witness Hartwick.
- 11 • Projects already in active construction.
- 12 • Some Operational Technology (OT) projects are not evaluated through the
- 13 GPM, as the GPM is designed for investments which upgrade the physical
- 14 distribution grid. The specific benefits which OT projects deliver are
- 15 discussed in more detail in witness Hartwick's testimony.

16

17 It is important to note that some programs and projects may not receive funding in
18 a particular year due to lower benefit-cost scores relative to other projects, but this
19 does not indicate that these programs or projects are not beneficial to customers, or
20 that they will not be selected in other years. Rather, all the programs and projects
21 identified by the Company and evaluated by the GPM provide system
22 improvements and may be funded at some point over the next several years. While
23 the strategic capital investment plan is primarily driven by the GPM, the Company
24 may adjust the annual plans based on changing circumstances and grid needs.

25

Line
No.

1 **Q82. Do the GPM scores and rankings have the potential to change over time?**

2 A82. Yes. As the Company continues to make investments in distribution infrastructure,
3 the effectiveness of the capital investment is examined on a regular basis. The
4 benefit-cost scores of the programs and projects may change over time as new data
5 becomes available. The prioritization ranking of the programs and projects may
6 change accordingly.

7

8 **Part IX: Capital/Reliability Model**

9 **Q83. Based on DO investments requested in this case, what system reliability**
10 **improvements are expected?**

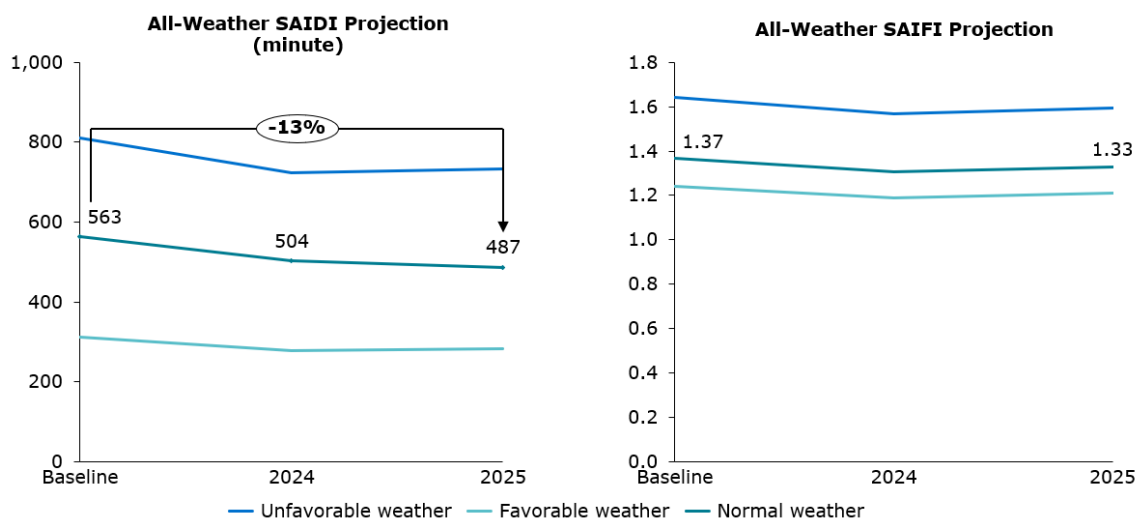
11 A83. The Company's reliability model projects that customers will experience an all-
12 weather SAIDI of 504 minutes in 2024 and 487 minutes in 2025 versus a historical
13 baseline of 563 minutes, assuming normal weather. Similarly, all weather SAIFI
14 will improve to 1.33 in 2025 from the historical baseline of 1.37. The model
15 assumes that due to timing of the execution of projects and programs, half of the
16 benefits are realized in the year of construction and full benefits are realized the
17 following calendar year. Graphs of expected reliability improvements are shown in
18 **Figure 10.**

Line
No.

1

Figure 10

All-Weather Reliability Projections



2

3 **Q84. How does the Company calculate its reliability projections?**

4 A84. The reliability calculations are performed at a circuit level based on historical
5 performance and the impact of planned investments on those circuits. The projected
6 performance of all circuits is summed to provide a system level projection. The
7 process to project reliability performance within the model can be summarized in
8 five steps:

- 9 ○ **Baseline:** Calculate circuit-level baseline reliability performance
- 10 ○ **Program impact:** Estimate impact of reliability programs
- 11 ○ **Degradation impact:** Estimate impact of system degradation
- 12 ○ **Investment plan:** Enter planned or expected in-service schedule for
- 13 reliability programs into model
- 14 ○ **Calculate Ex-MED performance:** Combine baseline performance with
- 15 investment plan on a circuit level to project future performance
- 16 ○ **Calculate All-weather performance:** Scale Ex-MED output to all weather
- 17 output and expected ranges

Line
No.

1 Each of these steps is described briefly below.

2

3 **Q85. How is the starting point, or circuit baseline calculated?**

4 A85. Each circuit has a baseline of reliability performance based on five years of
5 historical, non-MED event volume. Events are further divided into tree and non-
6 tree, single and multiple, and outage and non-outage events. An average customer's
7 interrupted (CI) and customer minutes interrupted (CMI) per event is used to
8 convert the volume of events to a SAIDI Ex-MED and SAIFI ex-MED baseline.

9

10 **Q86. Which reliability investments are included in the model?**

11 A86. The model's purpose is to forecast system reliability based on outage events on the
12 overhead distribution system (where the vast majority of the Company's outage
13 events occur), and therefore incorporates the impact of projects and programs
14 which have the potential reduce the impact of overhead outage events. The model
15 accounts for reliability improvements from six programs: Tree Trimming, 4.8kV
16 Hardening, PTMM, Customer Excellence, 4.8kV Conversion, and Automation.

17

18 **Q87. How does the company estimate the effectiveness of the reliability**
19 **investments?**

20 A87. For programs that have been established for over 3 years, the Company looks at a
21 year worth of non-MED historical circuit outage data before reliability
22 improvement is deployed. Non-MED event data for years post deployment is
23 compared to the baseline to calculate the reliability improvement. For newer
24 programs or projects, the reliability improvement is based either on the assessment
25 from industry subject matter experts, including DTE's Engineering, or by

Line
No.

1 comparing the newer program to similar established programs.
2 Programs impact the event types they are most likely to avoid. For example, if a
3 circuit has tree trimming planned, the model will project a reduction in tree-related
4 multiple events.

5

6 **Q88. How is the circuit performance projected?**

7 A88. The investment plan is entered in the model on a circuit level basis. For example,
8 the model has a list of circuits with planned PTMM in 2024 which is aligned with
9 our investment plan. If a circuit has no planned investment indicated in the model,
10 the model will calculate an increase in future event volume, or degradation, over
11 time. Circuits which have Tree Trimming, 4.8kV Hardening, PTMM, or Customer
12 Excellence work will have the program benefits applied to them by reducing the
13 future volume of events. Half of the maximum benefit will be applied in the year
14 of the investment, and the total benefit in the year after the investment. The benefit
15 will reduce over time due to factors such as the regrowth of trees, and the continued
16 aging of overhead equipment. The model assumes that significant rebuild work
17 from 4.8kV Conversion will deliver a consistent benefit for 10 years after the
18 investment without any degradation. The impact of the Automation investment is a
19 reduction in the customer interrupted (CI) per event on the circuit, but there is no
20 associated reduction in event volume.

21

22 **Q89. How are Ex-MED and all-weather reliability metrics calculated?**

23 A89. The primary output of the model is a projection of ex-MED event volume, which
24 is translated into SAIFI ex-MED and SAIDI ex-MED using a historical event
25 average CI and CMI per event. The ex-MED results are scaled to all-weather

Line
No.

1 projections by calculating the ex-MED to all weather performance relationship of
2 64 large utilities based on historical data available on EIA.gov. As an example, for
3 utilities who had a SAIDI ex-MED of 100 minutes in a given year, the range of All-
4 Weather SAIDI outcomes, excluding the top and bottom 20% of outcomes, was
5 140 minutes to 342 minutes. If the model projects the Company's SAIDI ex-MED
6 performance to be 100 minutes, it would also calculate a range of expected All-
7 weather outcomes to be 140 to 342 minutes, with an average performance
8 calculated as the median of the data set. This range, based on industry performance,
9 accounts for weather variability.

10

11 **Q90. Does the model capture all potential reliability benefits?**

12 A90. No, as mentioned the model captures the benefits of the investment programs which
13 deliver the majority of the improvements on the overhead distribution system.
14 Other programs such as URD replacement, Cable replacement, Breaker
15 replacement, Substation Risk projects will also reduce outage events and impact
16 reliability. For specific benefits from these projects, please refer to testimony from
17 Witnesses Elliott Andahazy, Deol, and Hartwick.

18

19 **Q91. How is this model an improvement upon previous reliability projections?**

20 A91. The structure of this model has many improvements over previous methods to
21 project reliability. First, the model is based on ex-MED events and reliability which
22 has less inherent variability than all-weather performance. Second, by modelling
23 the system on a circuit level basis, this methodology more accurately accounts for
24 benefits from different programs without double counting. Finally, as circuit
25 performance is disaggregated into many event types (tree vs non tree, single vs

Line
No.

1 multiple, outage vs non-outage), program improvements can more accurately be
2 modelled against the events they are most likely to address.

3

4 **Q92. Does the reliability model project emergent reductions and how are these**
5 **reductions shown in Exhibit A-12 Schedule B5.4?**

6 A92. Yes. The reliability model projected emergent reduction, along with the surge tree
7 trim capital reduction shown on Exhibit A-22, Schedule L1, line 33, are shown in
8 Exhibit A-12, Schedule B5.4, page 1, line 6.

9

10 **Part X: IIJA Grant Opportunities**

11 **Q93. What are IIJA grants?**

12 A93. The Infrastructure Investment and Jobs Act (IIJA)) was enacted federally in
13 November 2021. The goal of the IIJA grants is to provide funding opportunities in
14 multiple types of investments to catalyze public and private investment to enhance
15 the nation's infrastructure, with a particular focus on helping America's
16 disadvantaged communities. For electric infrastructure, the grants are mainly
17 administered in three broad categories: improving grid resilience, building smart
18 grids, and pursuing grid innovation.

19

20 **Q94. Did the Company seek grant funding to invest in the distribution system in**
21 **2023?**

22 A94. Yes. In 2023, the Company applied for two direct grants to improve the distribution
23 system: Section 40101(c) – Grid Resilience and Section 40107 – Smart Grid. The
24 company also applied for a grant from the Michigan Department of Environment,
25 Great Lakes, and Energy (EGLE), who is administering funds awarded through

Line
No.

1 Section 40101(d) – Preventing Outages and Enhancing the Resilience of the
2 Electric Grid. Additionally, the Company was a partner on an application for
3 Section 40103(b) – Grid Innovation Program. This grant was led by the State of
4 Michigan.

5

6 **Q95. Were any of the Company’s IIJA grant applications selected to be funded?**

7 A95. Yes. The DOE (Department of Energy) selected the Company’s Section 40107 –
8 Smart Grid application for investment in October 2023. This project will deploy
9 Adaptive Network Microgrids (ANM) on the distribution system in two
10 communities and is discussed in Witness Hartwick’s testimony. The Company
11 received positive feedback on its Section 40101(c) – Grid Resilience grant from the
12 DOE on the application, although was not selected. The Company is currently
13 waiting to hear the outcome for its Section 40101 (d) – Preventing Outages and
14 Enhancing the Resilience of the Electric Grid application filed on November 17th,
15 2023. DTE Electric expects a response from EGLE in the first half of 2024.

16

17 **Q96. Will the Company continue to seek additional IIJA grant funding to invest in**
18 **the distribution system in 2024?**

19 A96. Yes. The Company is currently pursuing the second round of funding for Section
20 40101 (c) – Grid Resilience, incorporating the feedback from the DOE on project
21 scope and strategic alignment. The Company filed a concept paper on January 12,
22 2024 and will continue to update our IIJA grant planning as requested with reports
23 filed in U-21227.

24

Line
No.

1 **Q97. What are the objectives and details of the 40101(d) Preventing Outages and**
2 **Enhancing the Resilience of the Electric Grid grant?**

3 A97. Unlike the two grants (Section 40101c and Section 40107), this grant is an indirect
4 grant for which the Company cannot directly apply. Instead, EGLE applied for
5 DOE funding with the support of the MPSC. EGLE was awarded the grant on June
6 30, 2023 and the Request for Proposal (RFP) was posted on EGLE's website on
7 October 3, 2023. The objectives of this grant are similar to the 40101(c) grant, with
8 a focus on improving energy resilience and investing in modernized grid
9 infrastructure, and are restricted to large utilities applicants. Overall, EGLE intends
10 to award approximately \$8 million in funding between the two largest utilities in
11 the state of Michigan (DTE Electric and Consumers Energy). The Company filed
12 an application on November 17, 2023. The Company's grant proposal is to support
13 activities that will harden and modernize electric services for residential customers
14 in Detroit and Highland Park with the impact of reducing electrical service outages
15 during storm for disadvantaged communities. These outages can have significant
16 economic impact due to loss of food or medicine, and cost of temporary shelter.
17 The proposal will investigate the most viable option to scale up a program to harden
18 electric service lines within the Company's service territory. Amongst the proposed
19 options for hardening services are (1) undergrounding overhead services, and (2)
20 replacing overhead services and tree trimming away from services. Additionally,
21 newly hardened residential services will be brought up to the Company's current
22 standard and will be capable of supporting future electrification.

23

24 **Q98. Is the Company requesting funding in this rate case for investments or**
25 **expenses that may be partially covered by any of the grants discussed above?**

Line
No.

1 A98. Yes. The investment beyond the grant funding needed for the Section 40107 - Smart
2 Grid award is covered in the Adaptive Networked Microgrid section of Witness
3 Hartwick's testimony. The Company is not seeking funding for the other two grants
4 that are still being pursued in this rate case.

5

6 **Q99. If the Company is successful at obtaining any of the grants discussed above**
7 **but not yet awarded, what will the Company's financial obligation be?**

8 A99. For the grants the Company is actively pursuing, a 1:1 funding match of federal
9 funds will be required. For example, in the 40101(c) grant application, if DOE
10 awards \$100 million of funding, DTE would need to contribute a minimum of \$100
11 million in matching funds. DTE Electric customers would receive system
12 improvements through the federal grants without having to fund the full investment
13 in the project(s) through electric rates. Because this case does not include any
14 requested investment for DTE Electric's match, it is expected that the cost recovery
15 for the Company's match amounts would be requested in future rate cases.

16

17 **Q100. What happens if the grant requires that the Company provide matching**
18 **funding for a grant project before it can be presented for approval in a future**
19 **rate case?**

20 A100. The Company will notify the Commission through the ongoing docket on IIJA
21 grants (U-21227) and discuss needed adjustments to the capital plan and funding
22 allocations.

23

24 **Part XI: Environmental Justice**

25 **Q101. How does the Company define environmental justice (EJ)?**

Line
No.

1 A101. The Company defines EJ in the context of the State of Michigan’s definition of
2 environmental justice as “the equitable treatment and meaningful involvement of
3 all people, regardless of race, color, national origin, ability, or income in the
4 development and application of laws, regulations, and policies that affect the
5 environment, as well as the places people live, work, play, worship, and learn.”⁸
6

7 **Q102. How did DTE Electric incorporate EJ in grid planning as described in the 2023**
8 **DGP?**

9 A102. Building on the 2021 DGP, the Company developed three key EJ objectives for the
10 2023 DGP; (1) incorporate EJ considerations in investment decisions by including
11 an EJ component in the Global Prioritization Model (GPM), (2) improve system
12 performance for vulnerable communities experiencing poor reliability through our
13 investment programs, and (3) provide support to vulnerable customers experiencing
14 outages during storms through community outreach efforts.
15

16 **Q103. Does the Company continue to leverage the State of Michigan MiEJScreen tool**
17 **for environmental justice data and the identification of vulnerable**
18 **communities?**

19 A103. Yes. DO continues to use the MiEJScreen Tool for its EJ data in analyzing
20 investment impacts on disadvantaged customers and communities. EGLE released
21 the draft version of the MiEJScreen tool in March of 2022, following extensive
22 stakeholder involvement including a public comment process.⁹ This tool combines
23 environmental conditions and population characteristics to highlight, by census

⁸ State of Michigan, Department of Environment, Great Lakes, and Energy, <https://www.michigan.gov/egle/public/learn/environmental-justice>, accessed January 23, 2024.

⁹ MiEJScreen: Environmental Justice Screening Tool (DRAFT) (michigan.gov) available at <https://www.michigan.gov/egle/maps-data/miejscreen?adlt=strict>

Line
No.

1 tract, where the most vulnerable communities in Michigan are located. EGLE does
2 not explicitly define the threshold for which communities are vulnerable and which
3 ones are not vulnerable. A final MiEJScreen tool has not been released.

4

5 **Q104. How did DTE Electric Distribution Operations define a vulnerable community**
6 **for use with the draft MiEJScreen Tool?**

7 A104. An 80% threshold definition was adopted for vulnerable communities using the
8 draft MiEJScreen Tool score, consistent with the U.S. EPA approach.¹⁰ Following
9 this approach, census tracts with a MiEJScreen composite score at or above the 80th
10 percentile are considered vulnerable communities for the purpose of this testimony
11 and associated analysis. The draft MiEJScreen composite score is calculated using
12 categories and indicators for environmental and population data as shown in **Figure**
13 **11** below. On November 18, 2022 the Commission directed its Energy
14 Affordability and Accessibility Collaborative to address definitions of terms such
15 as environmental justice, grid equity, and energy justice (Case No. U-20836, pp
16 462-463).

¹⁰ 80th percentile, EPA, <https://www.epa.gov/ejscreen/frequent-questions-about-ejscreen#q5>, accessed January 24, 2024.

Line
No.

1

Figure 11 MiEJScreen Overall Score Calculation

Categories	Environmental Exposure	Environmental Effects	Sensitive Populations	Socioeconomic Factors
Indicators	NATA Air Toxics Cancer Risk NATA Respiratory Hazard Index NATA Diesel Particulate Matter Particulate Matter (PM _{2.5}) Ozone Traffic Density	Proximity to Cleanup Sites Proximity to Hazardous Waste Facilities Impaired Water Bodies Proximity to Solid waste Sites and Facilities Lead Paint Indicator Proximity to RMP Sites Wastewater Discharge Indicator	Asthma Cardiovascular Disease Low Birth Weight Infants Blood Lead Level Life Expectancy	Low Income Population Black, Indigenous, People of Color Population Educational Attainment Linguistic Isolation Population Under Age 5 Population Over Age 64 Unemployment Housing Burden
Sub Scores	Environmental Conditions (Average percentile of Environmental Exposure indicators + 0.5 x average percentile of Environmental Effects indicators) <u>1.5</u>		Population Characteristics (Average percentile of Sensitive Population indicators + average percentile of Socioeconomic Factor indicators) <u>2</u>	
Score	Final Composite Score = Environmental Conditions score x Population Characteristics score MiEJScreen Score			

2

3 **Q105. Is the Company able to group reliability statistics by geographic area (i.e.,**
 4 **census tracts and zip codes) and align to scores from the draft MiEJScreen**
 5 **Tool?**

6 A105. Yes. DTE Electric tracks reliability statistics by customer, which are then rolled up
 7 to a circuit and substation. However, circuits often cross more than one census tract
 8 or zip code. DTE Electric has matched residential meters to the census tracts
 9 defined by the U.S. Census Bureau. Commercial properties are not surveyed as part
 10 of the U.S. Census, and therefore, their addresses and associated meters are not
 11 assigned to a census tract for the purposes of this analysis. There are some
 12 residential meters, due to ongoing data cleaning work, that have yet to be placed in
 13 a census tract/zip code. Currently, most meters have been successfully mapped to

Line
No.

1 zip code and census tract. There are some small census tracts with a small number
2 of customers where reliability statistics may be abnormally high or low due to small
3 sample size.

4

5 **Q106. Using available data, is the Company able to provide a geographic**
6 **representation of 2023 electric reliability data by census tracts?**

7 A106. Yes. Using the meters that are matched to census tracts, DTE Electric developed
8 reliability data for SAIFI and SAIDI by census tract and grouped the data into DTE
9 Electric reliability quartiles, with first quartile customers (shown below in green)
10 experiencing the best reliability and fourth quartile customers (shown below in red)
11 experiencing the worst reliability. Looking specifically at outage frequency, first
12 quartile reliability customers have a 2023 All-Weather SAIFI performance fewer
13 than 0.81 interruptions, second quartile customers range between 0.81 and 1.42
14 interruptions, third quartile customers are between 1.42 and 2.31 interruptions, and
15 fourth quartile customers have performance greater than 2.31 interruptions.
16 Looking at outage duration, first quartile reliability customers have a 2023 All-
17 Weather SAIDI performance less than 331 minutes, second quartile customers
18 range between 331 and 957 minutes, third quartile customers are between 957
19 minutes and 2,140 minutes, and fourth quartile customers have experienced outage
20 duration above 2,140 minutes. As discussed in Part I above, for 2023, a key impact
21 on All-Weather SAIDI was the single large ice/snow storm in February, 2023,
22 which significantly impacted both SAIDI and SAIFI reliability metrics. Maps for
23 SAIFI and SAIDI by census tract are included in **Figure 12 to Figure 15**.

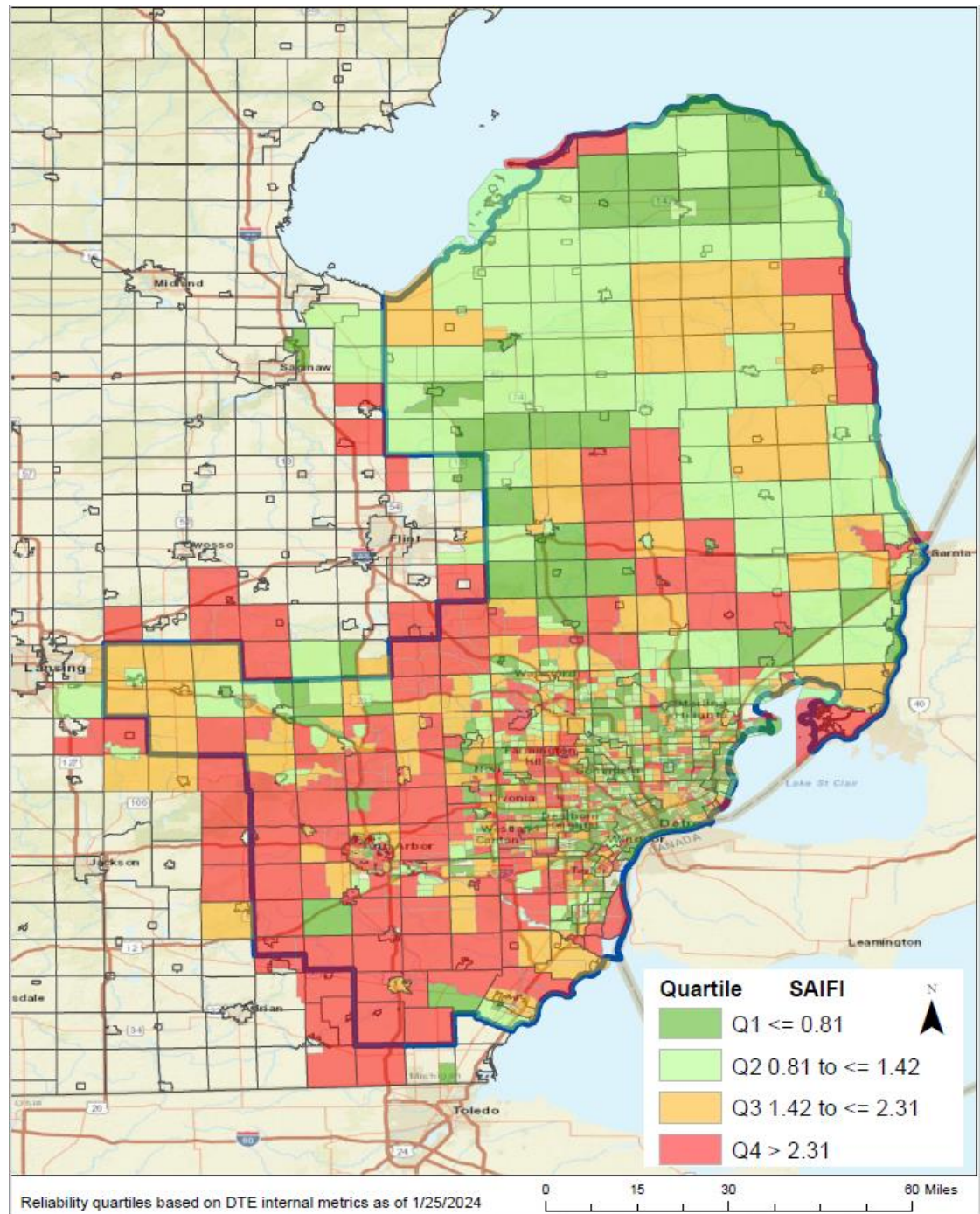
Line
No.

1

2

3

**Figure 12 2023 All Weather SAIFI by Census Tract
for DTE Electric (Full Electric Service Area)**



4

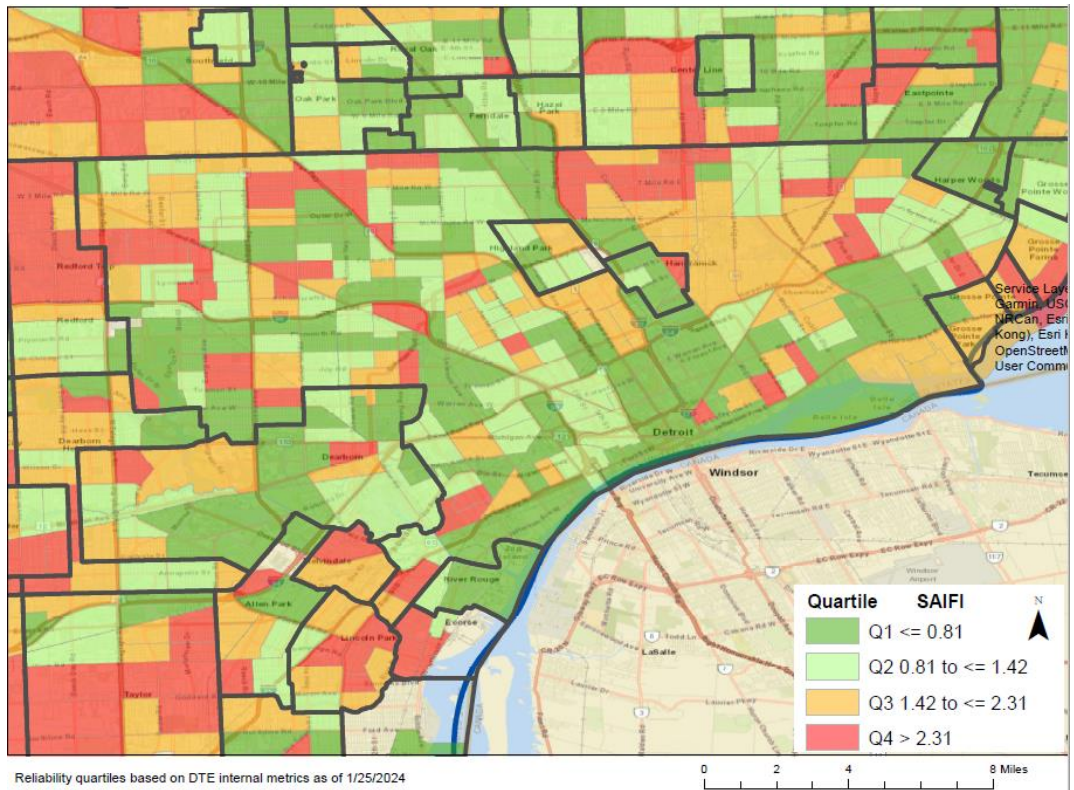
Line
No.

1

2

3

**Figure 13 2023 All Weather SAIFI by Census Tract
for DTE Electric (Metro Detroit Area)**

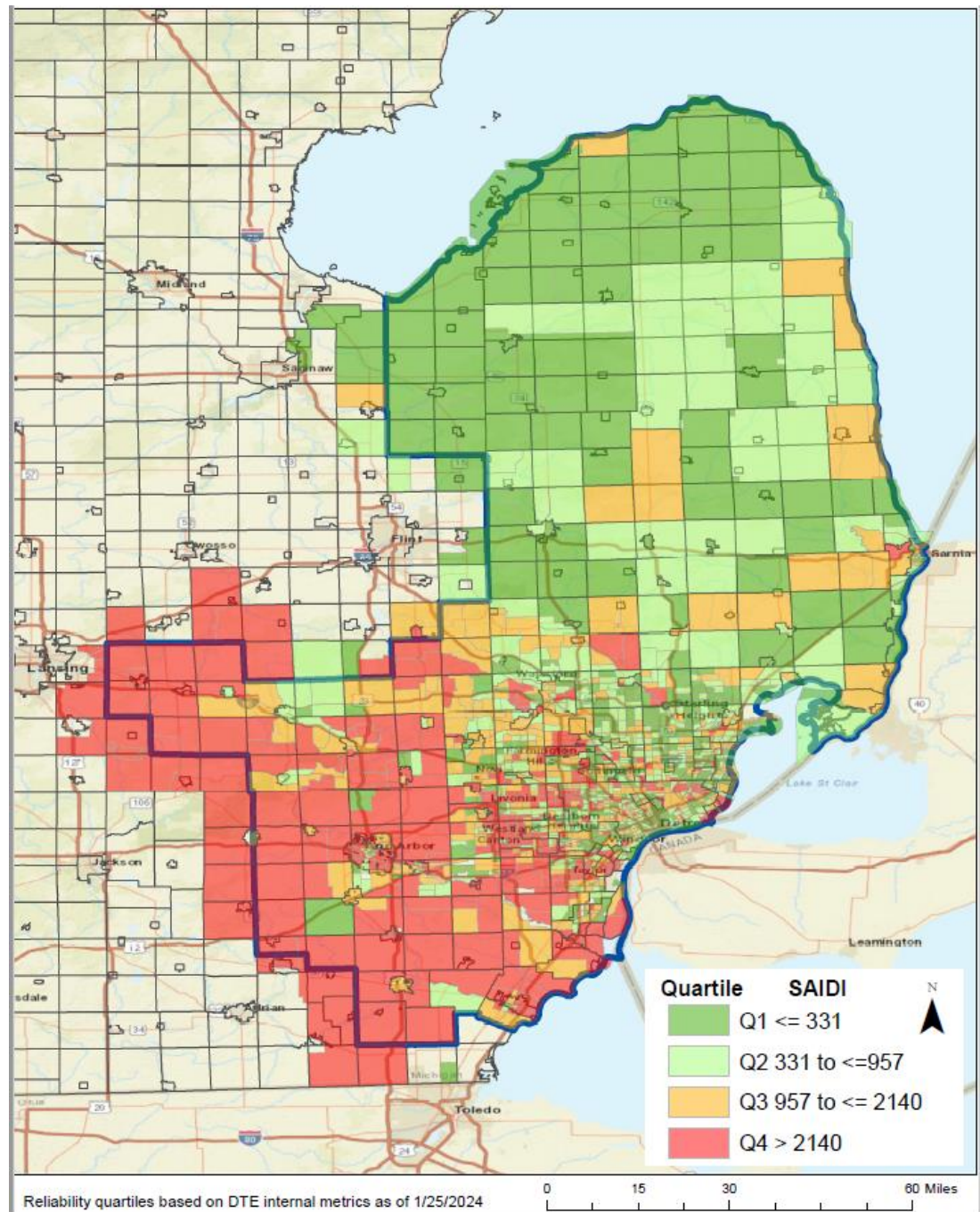


Line
No.

1

Figure 14 2023 All Weather SAIDI by Census Tract

2

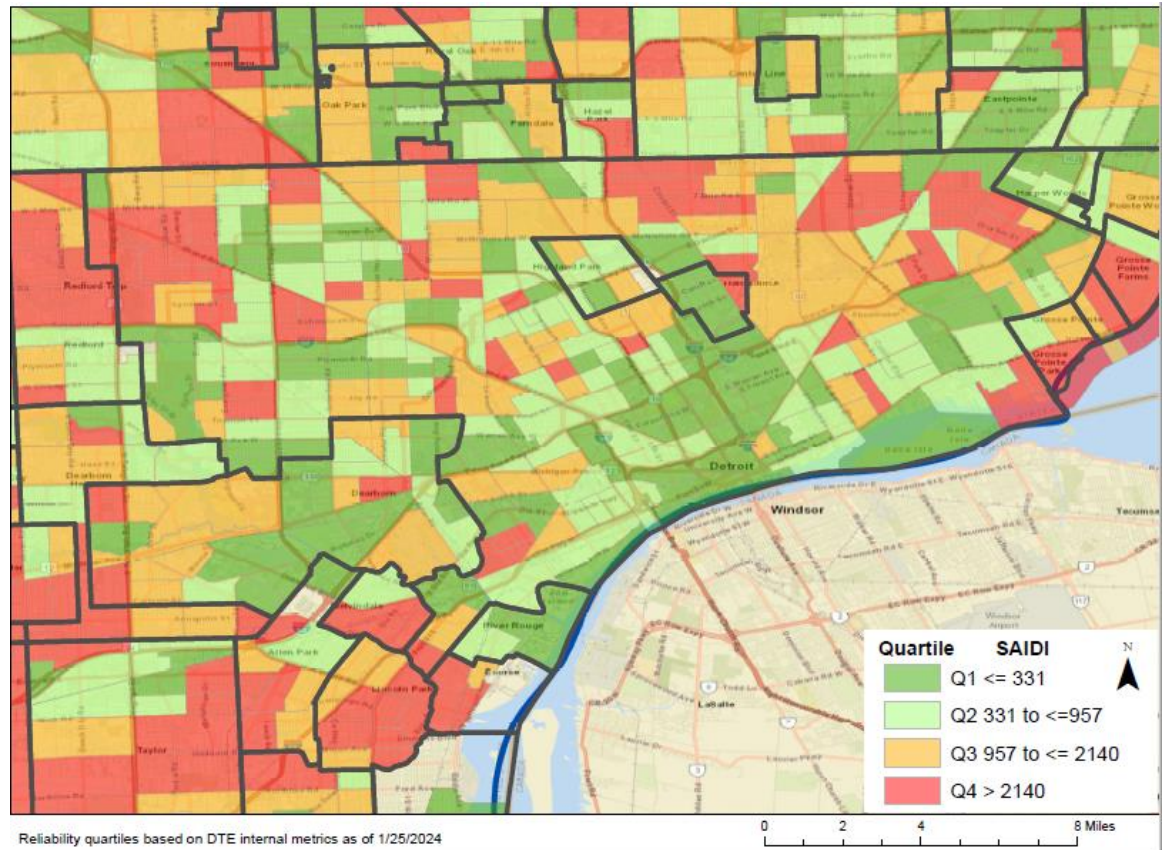
for DTE Electric (Full Electric Service Area)

3

Line
No.

1
2

**Figure 15 2023 All Weather SAIDI by Census Tract
for DTE Electric (Metro Detroit Area)**



3

Line
No.

1 **Q107. Are all census tracts equal in geographic size and population?**

2 A107. No. Census tracts vary in geographic size and population. According to the U.S.
3 Census Bureau, census tracts generally have a population size between 1,200 and
4 8,000 people, with an optimum size of 4,000 people.¹¹ In addition, the geographical
5 size of the tract does not represent how many people are in it. In some areas there
6 are large tracts (both first and fourth quartile) that have fewer customers in them,
7 compared to much smaller sized tracts in more dense urban areas. When the
8 reliability data is looked at in a map, as shown above, the lightly populated,
9 geographically large census tracts can visually skew the true reliability impact on
10 customers.

11

12 **Q108. How many vulnerable census tracks are there in DTE Electric's service**
13 **territory?**

14 A108. In the DTE Electric service territory, there are 483 census tracts that fall into the
15 range of having a composite draft MiEJScreen score at or above 80th percentile.
16 These 483 census tracts represent 29% of the total census tracts in DTE Electric's
17 service area and account for approximately 550,000 residential customers.¹²
18 Additionally, these tracts include a total of 1,032 circuits out of DTE Electric's
19 3,273 distribution circuits (32% of total circuits) and contain 8,289 circuit miles
20 compared to 41,905 total distribution circuit miles (20% of total distribution miles).

21

22 **Q109. What was the Commission's direction in Case No. U-21297 regarding more in-**
23 **depth EJ analysis?**

¹¹ US Census Bureau, Glossary, available at [Glossary \(census.gov\)](https://www.census.gov/programs-surveys/geography/about/glossary.html?adlt=strict#par_textimage_13), https://www.census.gov/programs-surveys/geography/about/glossary.html?adlt=strict#par_textimage_13 accessed January 14, 2023.

¹² There are a total of 1,643 census tracts in DTE Electric's service territory.

Line
No.

1 A109. The Commission stated in its order that future analysis of the MiEJScreen data
2 should be segmented in 5% gradations. As stated on page 93 of the U-21297 order:
3 “The Staff recommends, and the Commission agrees, that these gradations should
4 be defined initially as 0% to <5%, 5% to <10%, in 5% gradations up to 95%-100%
5 of the MiEJScreen composite score”.

6

7 **Q110. Has the Company performed analysis with 5% gradations of the MiEJScreen**
8 **relative to reliability performance?**

9 A110. Yes. The reliability performance in years 2020 through 2023, for SAIDI and SAIFI
10 metrics excluding MEDs and All-Weather compared to the systemwide levels are
11 shown in **Tables 10-13.**

Line
No.

1 **Table 10 All Weather SAIFI Reliability Performance of Census Tracts**
2 **(MiEJ score of 0% to 100%) Versus System Average**

3

Census Tract EJ % Group	Category	2020 SAIFI	2021 SAIFI	2022 SAIFI	2023 SAIFI
0 to 5	AW	3.12	2.88	2.37	3.01
>5 to 10	AW	2.46	2.47	1.95	2.22
>10 to 15	AW	1.68	2.29	1.94	1.97
>15 to 20	AW	2.13	2.00	1.49	2.02
>20 to 25	AW	1.55	2.29	1.56	2.15
>25 to 30	AW	1.47	2.01	1.43	1.99
>30 to 35	AW	1.26	1.96	1.49	1.93
>35 to 40	AW	1.32	1.72	1.31	2.21
>40 to 45	AW	1.08	1.50	1.12	1.86
>45 to 50	AW	1.42	1.58	1.17	1.64
>50 to 55	AW	1.25	1.53	1.16	1.68
>55 to 60	AW	1.10	1.39	1.37	1.52
>60 to 65	AW	1.18	1.29	0.96	1.51
>65 to 70	AW	1.15	1.48	1.18	1.90
>70 to 75	AW	1.29	1.58	1.13	1.58
>75 to 80	AW	1.20	1.50	1.08	1.71
>80 to 85	AW	1.23	1.56	1.18	1.47
>85 to 90	AW	1.11	1.14	1.12	1.54
>90 to 95	AW	1.04	1.33	1.03	1.52
>95 to 100	AW	0.83	1.19	1.15	1.49
No EJ Score	AW	0.83	0.92	1.01	1.27
Sytem Average	AW	1.29	1.58	1.25	1.72

Over performing system average
Under performing system average
System average

Line
No.

1 **Table 11 Excluding MEDs SAIFI Reliability Performance of Census**
2 **Tracts (MiEJ score of 0% to 100%) Versus System Average**

3

Census Tract EJ % Group	Category	2020 SAIFI	2021 SAIFI	2022 SAIFI	2023 SAIFI
0 to 5	Ex-MED	2.36	1.84	1.94	1.56
>5 to 10	Ex-MED	1.71	1.35	1.54	1.27
>10 to 15	Ex-MED	1.17	1.47	1.55	1.01
>15 to 20	Ex-MED	1.57	1.15	1.25	1.17
>20 to 25	Ex-MED	1.15	1.42	1.33	1.15
>25 to 30	Ex-MED	1.12	1.16	1.17	1.13
>30 to 35	Ex-MED	0.97	1.06	1.16	0.88
>35 to 40	Ex-MED	1.02	0.99	1.00	1.10
>40 to 45	Ex-MED	0.91	0.85	0.88	0.81
>45 to 50	Ex-MED	1.14	0.94	0.98	0.75
>50 to 55	Ex-MED	1.07	0.85	0.91	0.82
>55 to 60	Ex-MED	0.88	0.84	1.10	0.77
>60 to 65	Ex-MED	0.95	0.76	0.75	0.75
>65 to 70	Ex-MED	0.98	0.84	0.98	0.93
>70 to 75	Ex-MED	1.07	0.95	0.90	0.75
>75 to 80	Ex-MED	1.01	0.93	0.85	0.87
>80 to 85	Ex-MED	0.93	0.92	0.92	0.70
>85 to 90	Ex-MED	0.85	0.68	0.78	0.71
>90 to 95	Ex-MED	0.80	0.78	0.76	0.71
>95 to 100	Ex-MED	0.65	0.64	0.77	0.78
No EJ Score	Ex-MED	0.71	0.58	0.86	0.60
Sytem Average	Ex-MED	1.01	0.92	0.98	0.86

	Over performing system average
	Under performing system average
	System average

4

Line
No.

1 **Table 12 All Weather SAIDI Reliability Performance of Census Tracts**
2 **(MiEJ score of 0% to 100%) Versus System Average**

Census Tract EJ % Group	Category	2020 SAIDI	2021 SAIDI	2022 SAIDI	2023 SAIDI
0 to 5	AW	978	2656	1262	3278
>5 to 10	AW	863	1657	909	1604
>10 to 15	AW	384	930	916	1618
>15 to 20	AW	605	1096	576	1184
>20 to 25	AW	510	1291	527	1937
>25 to 30	AW	414	1174	611	1521
>30 to 35	AW	306	1211	692	1748
>35 to 40	AW	351	1027	666	1889
>40 to 45	AW	222	940	433	1834
>45 to 50	AW	330	999	426	1584
>50 to 55	AW	292	946	458	1482
>55 to 60	AW	300	775	531	1268
>60 to 65	AW	297	764	473	1363
>65 to 70	AW	228	816	416	1745
>70 to 75	AW	336	844	472	1515
>75 to 80	AW	325	820	389	1509
>80 to 85	AW	480	978	556	1419
>85 to 90	AW	351	705	735	1699
>90 to 95	AW	329	840	749	1675
>95 to 100	AW	266	804	923	1133
No EJ Score	AW	203	355	300	778
Sytem Average	AW	352	927	584	1542

	Over performing system average
	Under performing system average
	System average

4

Line
No.

**Table 13 Excluding MEDs SAIDI Reliability Performance of Census
Tracts (MiEJ score of 0% to 100%) Versus System Average**

Census Tract EJ % Group	Category	2020 SAIDI	2021 SAIDI	2022 SAIDI	2023 SAIDI
0 to 5	Ex-MED	342	398	487	373
>5 to 10	Ex-MED	291	213	296	320
>10 to 15	Ex-MED	153	209	274	236
>15 to 20	Ex-MED	218	150	238	212
>20 to 25	Ex-MED	168	248	182	239
>25 to 30	Ex-MED	176	177	188	217
>30 to 35	Ex-MED	123	136	152	158
>35 to 40	Ex-MED	147	138	146	173
>40 to 45	Ex-MED	108	111	103	152
>45 to 50	Ex-MED	154	149	131	135
>50 to 55	Ex-MED	144	124	128	136
>55 to 60	Ex-MED	102	112	150	155
>60 to 65	Ex-MED	132	114	138	139
>65 to 70	Ex-MED	101	131	120	138
>70 to 75	Ex-MED	154	122	115	119
>75 to 80	Ex-MED	124	128	106	145
>80 to 85	Ex-MED	158	147	156	149
>85 to 90	Ex-MED	123	111	123	130
>90 to 95	Ex-MED	136	112	115	129
>95 to 100	Ex-MED	118	94	129	142
No EJ Score	Ex-MED	97	68	98	80
Sytem Average	Ex-MED	142	136	146	157

	Over performing system average
	Under performing system average
	System average

Q111. What is the distribution of residential customers in each EJ Gradation?

A111. The distribution of residential customer in each gradation is highlighted in **Table 14** below. Approximately 27% of our residential customers fall into the 80% to 100% gradations.

Line
No.

1

Table 14 Residential Customers by EJ Gradations

Census Tract EJ % Group	Number of Residential Customers	% of Residential Customers
0-5%	7,569	<1%
5-10%	39,705	2%
10-15%	62,143	3%
15-20%	43,497	2%
20-25%	59,888	3%
25-30%	88,033	4%
30-35%	100,487	5%
35-40%	99,318	5%
40-45%	102,680	5%
45-50%	114,416	6%
50-55%	120,730	6%
55-60%	135,206	7%
60-65%	124,240	6%
65-70%	126,463	6%
70-75%	100,278	5%
75-80%	146,161	7%
80-85%	127,270	6%
85-90%	162,145	8%
90-95%	143,144	7%
95-100%	114,874	6%
Unmapped/Unscored*	38,383	2%
Total Residential Customers	2,056,630	100%

2

3 **Q112. How does the reliability performance of census tracts that have been identified**
4 **as vulnerable communities compare with the rest of the DTE Electric system?**

5 A112. As noted in **Table 10** and **Table 12**, vulnerable customers in the 80th percentile and
6 above see better reliability than the system average in SAIFI and SAIDI in both
7 All-Weather and Non-MED. All-Weather and Non-MEDs SAIFI is lower than the
8 system average in every year and every vulnerable community gradient. For Non-
9 MED SAIDI, the vast majority of years and vulnerable community gradients are
10 better than the system average. All-Weather shows more year-gradient
11 combinations above the system average but even for this metric, the majority of
12 instances are better than the system average.

13

Line
No.

1 **Q113. Has the company evaluated how its investment programs are reaching**
2 **vulnerable communities to improve electric distribution infrastructure and**
3 **reliability performance?**

4 A113. Yes. The Company has evaluated some of its largest distribution investment
5 projects and programs, 4.8kV Hardening, 4.8kV Conversion, and tree trim, with
6 respect to if the investment was made in a vulnerable area.

7
8 **Q114. What are the results of the investment analysis related to vulnerable**
9 **communities?**

10 A114. The results are summarized in **Table 15** below and indicate that the Company's
11 investments are supporting vulnerable customers and communities in southeast
12 Michigan, including the City of Detroit. This analysis is based on the draft
13 MiEJScreen Tool census tract data and Company investment data on the circuits
14 addressed by the following three programs over the timeframe 2018-2023: 4.8kV
15 Hardening, Tree Trimming and Conversions. For each of these investment
16 programs, **Table 15** shows total investment dollars by program, total program
17 investment in vulnerable communities, and percentage of program investment in
18 vulnerable communities. For example, of the nearly half billion dollars of
19 investment in the 4.8kV Hardening program since 2018, 85% of work performed
20 under the hardening program occurred in vulnerable communities. As discussed by
21 Witness Elliott Andahazy, the hardening program has resulted in documented
22 reliability and safety improvements, including reduction in the frequency and
23 duration of outages and fewer downed wires, through the program's clearing of
24 right of way, equipment upgrades, and removal of arc wire.

3

4

5

6

7

9

10

11

12

13

14

15

3

Tracts with MiEJ Score of 80% to 100%)

4

6

13

Line
No.

1

Table 17 Hardening Investments by EJ Gradations

2

EJ Gradations	2018 Investment (\$000)	2019 Investment (\$000)	2020 Investment (\$000)	2021 Investment (\$000)	2022 Investment (\$000)	2023 Investment (\$000)	2024 Investment Forecast (\$000)	2025 Investment Forecast (\$000)
0-5%	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 1,710	\$ -	\$ -
5-10%	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
10-15%	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
15-20%	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
20-25%	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
25-30%	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
30-35%	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
35-40%	\$ -	\$ -	\$ -	\$ -	\$ 1,955	\$ -	\$ -	\$ -
40-45%	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
45-50%	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
50-55%	\$ -	\$ -	\$ -	\$ 6,284	\$ -	\$ -	\$ -	\$ -
55-60%	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 211	\$ -
60-65%	\$ -	\$ -	\$ -	\$ 1,669	\$ 9,026	\$ -	\$ -	\$ -
65-70%	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
70-75%	\$ 1,077	\$ 2,300	\$ 1,821	\$ 3,032	\$ 2,747	\$ -	\$ -	\$ 7,401
75-80%	\$ 2,302	\$ -	\$ 868	\$ 16,682	\$ 1,691	\$ 4,148	\$ 2,177	\$ 1,595
80-85%	\$ 5,455	\$ 12,499	\$ 2,343	\$ 646	\$ 8,354	\$ 12,660	\$ -	\$ 3,777
85-90%	\$ 14,205	\$ 18,366	\$ 24,086	\$ 8,858	\$ 22,658	\$ 32,545	\$ 7,681	\$ 21,978
90-95%	\$ 16,413	\$ 13,456	\$ 15,495	\$ 13,563	\$ 39,625	\$ 24,866	\$ 20,547	\$ 44,776
95-100%	\$ 776	\$ 1,644	\$ 9,505	\$ 12,315	\$ 65,540	\$ 40,755	\$ 45,717	\$ 40,409
Unmapped/Unscored*	\$ 95	\$ 12	\$ 1,048	\$ 2,313	\$ 5,885	\$ 10,326	\$ 3,667	\$ 5,063
Total Investment (\$)	\$ 40,325	\$ 48,278	\$ 55,165	\$ 65,362	\$ 157,482	\$ 127,010	\$ 80,000	\$ 125,000

3

Line
No.

1

Table 18 Percent of Hardening Investments by EJ Gradations

EJ Gradations	2018 Investment (%)	2019 Investment (%)	2020 Investment (%)	2021 Investment (%)	2022 Investment (%)	2023 Investment (%)	2024 Investment Forecast (%)	2025 Investment Forecast (%)
0-5%	0%	0%	0%	0%	0%	1%	0%	0%
5-10%	0%	0%	0%	0%	0%	0%	0%	0%
10-15%	0%	0%	0%	0%	0%	0%	0%	0%
15-20%	0%	0%	0%	0%	0%	0%	0%	0%
20-25%	0%	0%	0%	0%	0%	0%	0%	0%
25-30%	0%	0%	0%	0%	0%	0%	0%	0%
30-35%	0%	0%	0%	0%	0%	0%	0%	0%
35-40%	0%	0%	0%	0%	1%	0%	0%	0%
40-45%	0%	0%	0%	0%	0%	0%	0%	0%
45-50%	0%	0%	0%	0%	0%	0%	0%	0%
50-55%	0%	0%	0%	10%	0%	0%	0%	0%
55-60%	0%	0%	0%	0%	0%	0%	0%	0%
60-65%	0%	0%	0%	3%	6%	0%	0%	0%
65-70%	0%	0%	0%	0%	0%	0%	0%	0%
70-75%	3%	5%	3%	5%	2%	0%	0%	6%
75-80%	6%	0%	2%	26%	1%	3%	3%	1%
80-85%	14%	26%	4%	1%	5%	10%	0%	3%
85-90%	35%	38%	44%	14%	14%	26%	10%	18%
90-95%	41%	28%	28%	21%	25%	20%	26%	36%
95-100%	2%	3%	17%	19%	42%	32%	57%	32%
Unmapped/Unscored	0%	0%	2%	4%	4%	8%	5%	4%
Total Investment (%)	100%	100%	100%	100%	100%	100%	100%	100%

2

Table 19 Tree Trim Investments by EJ Gradations

EJ Gradations	2018 Investment (\$000)	2019 Investment (\$000)	2020 Investment (\$000)	2021 Investment (\$000)	2022 Investment (\$000)	2023 Investment (\$000)	2024 Investment Forecast (\$000)	2025 Investment Forecast (\$000)
0-5%	\$ 553	\$ 252	\$ 948	\$ 1,634	\$ 3,055	\$ 1,487	\$ 501	\$ 303
5-10%	\$ 4,596	\$ 4,355	\$ 11,250	\$ 9,290	\$ 4,653	\$ 9,113	\$ 3,301	\$ 494
10-15%	\$ 7,087	\$ 1,076	\$ 9,756	\$ 11,195	\$ 12,626	\$ 13,319	\$ 5,131	\$ 1,161
15-20%	\$ 2,808	\$ 2,407	\$ 7,037	\$ 7,118	\$ 6,069	\$ 8,227	\$ 5,623	\$ 5,258
20-25%	\$ 2,809	\$ 5,681	\$ 8,683	\$ 7,320	\$ 11,946	\$ 5,077	\$ 11,032	\$ 12,265
25-30%	\$ 4,056	\$ 3,714	\$ 8,551	\$ 15,421	\$ 12,696	\$ 8,208	\$ 7,503	\$ 5,232
30-35%	\$ 3,008	\$ 2,815	\$ 14,158	\$ 10,839	\$ 16,395	\$ 9,867	\$ 5,498	\$ 4,543
35-40%	\$ 3,047	\$ 5,011	\$ 9,332	\$ 7,666	\$ 15,467	\$ 8,204	\$ 5,311	\$ 8,483
40-45%	\$ 3,415	\$ 2,496	\$ 4,657	\$ 8,498	\$ 13,595	\$ 7,857	\$ 3,986	\$ 3,649
45-50%	\$ 4,059	\$ 6,039	\$ 4,847	\$ 7,315	\$ 11,990	\$ 11,789	\$ 7,463	\$ 5,331
50-55%	\$ 2,204	\$ 4,604	\$ 4,730	\$ 10,125	\$ 13,127	\$ 5,841	\$ 6,768	\$ 4,540
55-60%	\$ 1,611	\$ 4,281	\$ 5,338	\$ 6,987	\$ 10,363	\$ 6,555	\$ 9,179	\$ 5,565
60-65%	\$ 1,746	\$ 3,820	\$ 5,864	\$ 7,329	\$ 9,856	\$ 5,702	\$ 3,664	\$ 4,726
65-70%	\$ 1,659	\$ 2,560	\$ 5,860	\$ 4,182	\$ 11,035	\$ 4,402	\$ 4,862	\$ 7,786
70-75%	\$ 1,028	\$ 3,209	\$ 4,676	\$ 2,664	\$ 4,782	\$ 3,696	\$ 5,259	\$ 5,338
75-80%	\$ 2,187	\$ 3,831	\$ 5,980	\$ 5,654	\$ 10,001	\$ 5,855	\$ 8,571	\$ 9,488
80-85%	\$ 4,758	\$ 4,967	\$ 3,119	\$ 8,166	\$ 15,094	\$ 5,759	\$ 8,316	\$ 10,553
85-90%	\$ 7,880	\$ 23,046	\$ 7,664	\$ 6,750	\$ 13,184	\$ 8,647	\$ 20,166	\$ 5,072
90-95%	\$ 7,856	\$ 13,901	\$ 14,559	\$ 4,648	\$ 16,324	\$ 10,152	\$ 16,101	\$ 5,868
95-100%	\$ 5,444	\$ 14,573	\$ 7,846	\$ 8,734	\$ 13,113	\$ 15,055	\$ 13,239	\$ 981
Unmapped/Unscored*	\$ 9,939	\$ 14,193	\$ 24,073	\$ 10,699	\$ 19,887	\$ 22,648	\$ 11,458	\$ 15,819
Total Investment (%)	\$ 81,752	\$ 126,831	\$ 168,926	\$ 162,235	\$ 245,260	\$ 177,459	\$ 162,930	\$ 122,456

3

Line
No.

1

Table 20 Percent of Tree Trim Investments by EJ Gradations

EJ Gradations	2018 Investment (%)	2019 Investment (%)	2020 Investment (%)	2021 Investment (%)	2022 Investment (%)	2023 Investment (%)	2024 Investment Forecast (%)	2025 Investment Forecast (%)
0-5%	1%	0%	1%	1%	1%	1%	0%	0%
5-10%	6%	3%	7%	6%	2%	5%	2%	0%
10-15%	9%	1%	6%	7%	5%	8%	3%	1%
15-20%	3%	2%	4%	4%	2%	5%	3%	4%
20-25%	3%	4%	5%	5%	5%	3%	7%	10%
25-30%	5%	3%	5%	10%	5%	5%	5%	4%
30-35%	4%	2%	8%	7%	7%	6%	3%	4%
35-40%	4%	4%	6%	5%	6%	5%	3%	7%
40-45%	4%	2%	3%	5%	6%	4%	2%	3%
45-50%	5%	5%	3%	5%	5%	7%	5%	4%
50-55%	3%	4%	3%	6%	5%	3%	4%	4%
55-60%	2%	3%	3%	4%	4%	4%	6%	5%
60-65%	2%	3%	3%	5%	4%	3%	2%	4%
65-70%	2%	2%	3%	3%	4%	2%	3%	6%
70-75%	1%	3%	3%	2%	2%	2%	3%	4%
75-80%	3%	3%	4%	3%	4%	3%	5%	8%
80-85%	6%	4%	2%	5%	6%	3%	5%	9%
85-90%	10%	18%	5%	4%	5%	5%	12%	4%
90-95%	10%	11%	9%	3%	7%	6%	10%	5%
95-100%	7%	11%	5%	5%	5%	8%	8%	1%
Unmapped/Unscored*	12%	11%	14%	7%	8%	13%	7%	13%
Total Investment (%)	100%	100%	100%	100%	100%	100%	100%	100%

2

Line
No.

1

Table 21 Conversion Investments by EJ Gradations

EJ Gradations	2018 Investment (\$000)	2019 Investment (\$000)	2020 Investment (\$000)	2021 Investment (\$000)	2022 Investment (\$000)	2023 Investment (\$000)	2024 Investment Forecast (\$000)	2025 Investment Forecast (\$000)
0-5%	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
5-10%	\$ -	\$ -	\$ -	\$ 127	\$ 51	\$ 399	\$ 2,079	\$ 2,735
10-15%	\$ 128	\$ 583	\$ 660	\$ 464	\$ 1,118	\$ 439	\$ 1,601	\$ 2,788
15-20%	\$ 203	\$ 618	\$ 665	\$ 2,359	\$ 5,468	\$ 1,748	\$ 5,341	\$ 1,132
20-25%	\$ 511	\$ 1,142	\$ 692	\$ 2,423	\$ 7,370	\$ 3,787	\$ 5,099	\$ 5,971
25-30%	\$ 201	\$ 483	\$ 324	\$ 523	\$ 480	\$ 2,094	\$ 6,093	\$ 4,996
30-35%	\$ 225	\$ 811	\$ 427	\$ 3,753	\$ 9,445	\$ 3,464	\$ 7,425	\$ 13,410
35-40%	\$ 339	\$ 159	\$ 112	\$ 143	\$ 329	\$ 319	\$ 484	\$ 986
40-45%	\$ 11	\$ 66	\$ -	\$ 16	\$ 65	\$ 235	\$ 433	\$ 1,824
45-50%	\$ 60	\$ 189	\$ 14	\$ 505	\$ 4,188	\$ 1,656	\$ 1,617	\$ 4,544
50-55%	\$ 1,764	\$ 784	\$ 154	\$ 380	\$ 1,141	\$ 887	\$ 2,099	\$ 5,312
55-60%	\$ 82	\$ 185	\$ 50	\$ 793	\$ 2,362	\$ 6,227	\$ 9,902	\$ (27)
60-65%	\$ 1,072	\$ 413	\$ 176	\$ 340	\$ 106	\$ 497	\$ 1,884	\$ 6,280
65-70%	\$ 877	\$ 275	\$ 58	\$ 595	\$ 1,101	\$ 8,909	\$ 16,676	\$ 144
70-75%	\$ 272	\$ 75	\$ 114	\$ 1,001	\$ 295	\$ 833	\$ 2,378	\$ 2,818
75-80%	\$ 2,313	\$ 2,497	\$ 3,125	\$ 3,149	\$ 4,188	\$ 11,090	\$ 21,576	\$ 11,318
80-85%	\$ 381	\$ 187	\$ 183	\$ 816	\$ 3,335	\$ 11,149	\$ 9,145	\$ 15,499
85-90%	\$ 1,440	\$ 495	\$ 297	\$ 2,147	\$ 4,319	\$ 11,646	\$ 9,212	\$ 17,790
90-95%	\$ 2,475	\$ 1,102	\$ 1,157	\$ 4,732	\$ 8,542	\$ 18,081	\$ 37,126	\$ 35,191
95-100%	\$ 11,423	\$ 9,836	\$ 15,814	\$ 32,162	\$ 44,649	\$ 67,524	\$ 73,157	\$ 83,132
Unmapped/Unscored*	\$ 1,653	\$ 690	\$ 437	\$ 2,665	\$ 5,930	\$ 11,126	\$ 15,237	\$ 30,475
Total Investment (\$)	\$ 25,429	\$ 20,591	\$ 24,460	\$ 59,092	\$ 104,483	\$ 162,109	\$ 228,563	\$ 246,318

2

3

Table 22 Percent of Conversion Investments by EJ Gradations

4

EJ Gradations	2018 Investment (%)	2019 Investment (%)	2020 Investment (%)	2021 Investment (%)	2022 Investment (%)	2023 Investment (%)	2024 Investment Forecast (%)	2025 Investment Forecast (%)
0-5%	0%	0%	0%	0%	0%	0%	0%	0%
5-10%	0%	0%	0%	0%	0%	0%	1%	1%
10-15%	1%	3%	3%	1%	1%	0%	1%	1%
15-20%	1%	3%	3%	4%	5%	1%	2%	0%
20-25%	2%	6%	3%	4%	7%	2%	2%	2%
25-30%	1%	2%	1%	1%	0%	1%	3%	2%
30-35%	1%	4%	2%	6%	9%	2%	3%	5%
35-40%	1%	1%	0%	0%	0%	0%	0%	0%
40-45%	0%	0%	0%	0%	0%	0%	0%	1%
45-50%	0%	1%	0%	1%	4%	1%	1%	2%
50-55%	7%	4%	1%	1%	1%	1%	1%	2%
55-60%	0%	1%	0%	1%	2%	4%	4%	0%
60-65%	4%	2%	1%	1%	0%	0%	1%	3%
65-70%	3%	1%	0%	1%	1%	5%	7%	0%
70-75%	1%	0%	0%	2%	0%	1%	1%	1%
75-80%	9%	12%	13%	5%	4%	7%	9%	5%
80-85%	1%	1%	1%	1%	3%	7%	4%	6%
85-90%	6%	2%	1%	4%	4%	7%	4%	7%
90-95%	10%	5%	5%	8%	8%	11%	16%	14%
95-100%	45%	48%	65%	54%	43%	42%	32%	34%
Unmapped/Unscored	6%	3%	2%	5%	6%	7%	7%	12%
Total Investment (%)	100%	100%	100%	100%	100%	100%	100%	100%

Line
No.

1 **Q117. Is the investment in vulnerable communities reflective of DTE Electric's**
2 **ongoing efforts to improve reliability in vulnerable communities?**

3 A117. Yes. As highlighted in **Table 15**, 85%, 64%, and 25 % of the investment in the
4 4.8kV Hardening, 4.8kV Conversion, and Tree Trim programs for the time period
5 2018 to 2023 was made in vulnerable communities. Significant investment is
6 expected to continue in these vulnerable communities in future years 2024-2025 as
7 illustrated in **Table 16** including 90%, 61%, and 28% of the total investment in the
8 Hardening, Conversion, and Tree Trim. Both the Company's historical and future
9 projected investment, is consistent with DTE Electric's commitment to improving
10 reliability in vulnerable communities.

11

12 **Q118. Has the Company incorporated Environmental Justice considerations into the**
13 **GPM for future Distribution Operations investments, including investments**
14 **in this case?**

15 A118. Yes. As described in the DGP section of testimony above, the Company has
16 included EJ scoring from the MiEJScreen tool in the GPM calculation. Projects in
17 more vulnerable areas will receive a higher score and have a better chance of being
18 selected for investment.

19

20 **Q119. How is the Company addressing the circuits with the worst reliability that**
21 **have also been identified as serving vulnerable customers?**

22 A119. The Company has either already invested in recent improvements or has plans to
23 improve performance of the 4th quartile worst performing circuits that are in
24 vulnerable communities through our investment programs, Tree Trim, PTMM,
25 Conversion, Customer Excellence, and 4.8kV Hardening. The Company has

Line
No.

1 identified 191 distribution circuits in vulnerable communities which fall in the
2 fourth quartile for reliability performance based on a five-year historic average.
3 Approximately 55% of the fourth quartile circuits have recently had reliability work
4 performed, while 45% of the circuits are planned to be addressed in 2024-2026
5 investment programs.

6

7 **Q120. What are the Company's future plans to address EJ in the context of**
8 **distribution planning and operations?**

9 A120. DTE Electric plans to continue to analyze reliability and investment data using the
10 draft MiEJScreen tool, including the consideration of any updates based on the
11 state's release of the tool's final version. The company intends continue to include
12 EJ considerations in investment decisions for all areas, as well as continue to
13 address poor performing circuits in vulnerable communities. Finally, DTE Electric
14 will continue to look for potential IIJA grant opportunities that invest in
15 infrastructure-related programs to benefit vulnerable communities in alignment
16 with the Biden Administration's Justice40 initiative.¹³

17

18 **Part XII: Municipal Project Coordination**

19 **Q121. What did the MPSC Case No. U-21297 order the Company to do with regard**
20 **to municipal project coordination?**

21 A121. The Commission stated on page 375 that:

¹³ The White House, Justice40: A Whole-of-Government Initiative, available at: [Justice40 Initiative | Environmental Justice | The White House](https://www.whitehouse.gov/environmentaljustice/justice40/?adlt=strict),
<https://www.whitehouse.gov/environmentaljustice/justice40/?adlt=strict> accessed January 14, 2023.

Line
No.

1 “In its next general rate case, DTE Electric Company shall demonstrate its efforts
2 to improve communication and coordination with local governments regarding
3 construction activities, as described in this order” (page 375).
4

5 **Q122. How does the Company currently coordinate projects with municipalities?**

6 A122. When DTE is ready to move forward with a capital project the Company
7 coordinates with the appropriate municipal personnel to set up a briefing meeting
8 to discuss the details of the project, benefits, and collaboration opportunities of the
9 work. We request that the municipality provide any potential conflicts to the project
10 before permits are sought. This provides both the municipality and DTE some
11 assurance that the planned project does not conflict with a municipal project,
12 whether it's in the conceptual or planned stage.
13

14 Once the project is in progress, periodic updates are provided to the municipality
15 and meetings may be held work through any questions that arise.
16

17 **Q123. Does the Company have ongoing efforts to improve communication and**
18 **coordination with municipalities?**

19 A123. Yes. The company is working to improve the frequency of updates to municipalities
20 and garnering feedback to determine their preferred methods to receiving these
21 updates. In addition, we are working with county road commission to support their
22 projects, and to coordinate where possible to avoid conflicts.
23

24 **Q124. Does this complete your direct testimony?**

25 A124. Yes, it does.

Michigan Public Service Commission
DTE Electric Company
U-21297 2022 Forecast vs. U-21534 Actuals
Distribution Plant
(\$000)

Case No.: U-21534
Exhibit: A-23 Revised
Schedule: M1
Witness: A. J. Kryscynski
Page: 1 of 9

Line No.	Description	(a)	(b)	(c)	(c)	
		U-21297 Forecast 12 mos. ending 12/31/2022	U-21534 Actuals 12 mos. ending 12/31/2022	Over / (Under) Forecast	Percentage	
1	Base Capital Programs					
2	Emergent Replacements					
3	Storm	176,904	181,326	4,422	2%	
4	Non - Storm	265,214	263,014	(2,200)	-1%	
5	Substation Reactive	45,422	40,382	(5,040)	-11%	
6	Emergent Replacement Reduction Based on Strategic Spend	-	-	-	0%	
7	Subtotal Emergent Replacements	487,541	484,722	(2,819)	-1%	
8	Customer Connections, Relocations & Other					
9	Connections and New Load	217,753	214,093	(3,660)	-2%	
10	Relocations	26,124	22,776	(3,348)	-13%	
11	Electric System Equipment	31,984	30,180	(1,804)	-6%	
12	NRUC and Improvement Blankets	36,629	32,851	(3,778)	-10%	
13	General Plant, Tools & Equipment and Miscellaneous	7,528	8,103	576	8%	
14	Public Lighting Department Project	13,600	13,440	(160)		
15	Subtotal Customer Connections, Relocations & Other	333,617	321,443	(12,174)	-4%	
16	Customer Advances for Construction	(26,755)	(24,969)	1,787	-7%	
17	Total Base Capital Programs	794,403	781,196	(13,206)	-2%	
18						
19	Strategic Capital Programs					
20	Infrastructure Resilience and Hardening	384,109	418,440	34,331	9%	
21	Infrastructure Redesign and Modernization	162,735	173,059	10,324	6%	
22	Technology and Automation	98,276	123,441	25,164	26%	
23	Subtotal Strategic Capital Programs	645,120	714,939	69,819	11%	
25	Total Capital	1,439,523	1,496,136	56,613	4%	

Michigan Public Service Commission
DTE Electric Company
U-21297 2022 Forecast vs. U-21534 Actuals
Distribution Plant - Connections, Relocations and Other
(\$000)

Case No.: U-21534
Exhibit: A-23 Revised
Schedule: M1
Witness: A. J. Kryscynski
Page: 2 of 9

(a)		(b)	(c)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2022	U-21534 Actuals 12 mos. ending 12/31/2022	Over / (Under) Forecast	Explanation 1/
1	<u>Connections and New Load</u>				
2	Projected Small Load Growth Projects (Blanket)	14,981	18,236	3,256	
3					
4	Projected Customer Connections	129,249	123,726	(5,523)	
5	Projected Customer Connections CIAC	<u>(22,338)</u>	<u>(17,654)</u>	<u>4,683</u>	
6	Projected Customer Connections (Net of CIAC)	106,912	106,072	(840)	
7					
8	Projected New Business Projects	73,523	72,131	(1,392)	
9	Projected New Business Projects CIAC	<u>(2,758)</u>	<u>(5,151)</u>	<u>(2,393)</u>	
10	Projected New Business Projects (net of CIAC)	70,765	66,980	(3,786)	
11					
12	Incremental Infrastructure for EV	<u>-</u>	<u>-</u>	<u>-</u>	
13					
14	Total Connections and New Load	217,753	214,093	(3,660)	Less than forecasted customer demand in 2022
15	Total Connections and New Load CIAC	<u>(25,096)</u>	<u>(22,805)</u>	<u>2,290</u>	
16	Total Connections and New Load (Net of CIAC)	192,657	191,288	(1,369)	
17					
18	<u>Relocations</u>				
19	Projected Small Relocation Projects (Blanket)	9,521	8,439	(1,082)	
20					
21	Major Infrastructure Relocation Project				
22	Gordie Howe International Bridge	484	235	(249)	
23	I-375 Relocations	-	-	-	
24					
25	Relocation Projects (excl. Major Infrastructure Projects)	16,119	14,103	(2,016)	
26	Relocation Projects CIAC	<u>(1,660)</u>	<u>(2,163)</u>	<u>(503)</u>	
27	Subtotal Relocation Projects (Net of CIAC)	14,459	11,940	(2,519)	
28					
29	Total Relocations	26,124	22,776	(3,348)	
30	Total Relocations CIAC	<u>(1,660)</u>	<u>(2,163)</u>	<u>(503)</u>	
31	Total Relocations (Net of CIAC)	24,464	20,613	(3,851)	Less than forecasted customer demand in 2022
32					
33	Electric System Equipment				
34	Distribution Transformers & Regulators	8,991	9,027	37	
35	Projected Major Equipment	7,166	5,552	(1,614)	
36	Projected Meters	<u>15,827</u>	<u>15,601</u>	<u>(227)</u>	
37	Total Electric System Equipment	31,984	30,180	(1,804)	
38					
39	NRUC and Improvement Blankets				
40	Projected System Improvements	23,187	22,289	(897)	
41	Projected Normal Retirement Unit Changeouts (NRUC)	5,490	4,981	(509)	
42	Projected Operational Technologies	5,692	5,581	(112)	
43	Batteries and Chargers	2,254	-	(2,254)	Moved to the Resilience section - U-21534 Exhibit A-12, Schedule B5.4, pg. 13, Line 25
44	Animal Mitigation	<u>5</u>	<u>-</u>	<u>(5)</u>	
45	Total NRUC and Improvement Blankets	36,629	32,851	(3,778)	
46					

Michigan Public Service Commission
DTE Electric Company
U-21297 2022 Forecast vs. U-21534 Actuals
Distribution Plant - Connections, Relocations and Other
(\$000)

Case No.: U-21534
Exhibit: A-23 Revised
Schedule: M1
Witness: A. J. Kryscynski
Page: 3 of 9

	(a)	(b)	(c)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2022	U-21534 Actuals 12 mos. ending 12/31/2022	Over / (Under) Forecast	Explanation 1/
47	General Plant, Tools & Equipment and Miscellaneous				
48	Projected Substation Physical Security	724	655	(69)	
49	Projected General Plant, Tools & Equipment and Miscellaneous	6,803	7,448	645	
50	Total General Plant, Tools & Equipment and Miscellaneous	7,527	8,103	576	
51					
52	Public Lighting Department Project	13,600	13,440	(160)	
53					
54	Total Customer Connections, Relocations & Other	333,617	321,443	(12,174)	
55	Total Cust Connections, Relocations & Other CIAC	(26,755)	(24,968)	1,787	
56	Total Cust Connections, Relocations & Other Net of CIAC	306,862	296,475	(10,387)	

1/ Variance greater than two million dollars are explained

Michigan Public Service Commission
DTE Electric Company
U-21297 2022 Forecast vs. U-21534 Actuals
Distribution Plant - Infrastructure Resilience and Hardening
(\$000)

Case No.: U-21534
Exhibit: A-23 Revised
Schedule: M1
Witness: A. J. Kryscynski
Page: 4 of 9

(a)		(b)	(c)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2022	U-21534 Actuals 12 mos. ending 12/31/2022	Over / (Under) Forecast	Explanation 1/
1	<u>Infrastructure Resilience and Hardening</u>				
2	Mobile Fleet Program	13,566	15,234	1,668	
3	Substation Risk: Drexel	1,915	1,898	(17)	
4	Substation Risk: Chestnut	161	64	(97)	
5	Substation Risk: Savage	562	577	15	
6	Substation Risk: Apache	3,381	4,653	1,272	
7	Substation Risk: Port Huron	184	184	(0)	
8	Substation Risk: Belleville Switchgear Decommission	1,206	1,234	27	
9	Substation Risk: McGraw	10,740	12,699	1,959	
10	Substation Risk: Voyager	200	201	1	
11	Substation Risk: Flood Defense Program	74	87	13	
12	4.8 kV Hardening	151,314	157,482	6,168	Company was able to complete more work than forecast
13	Pole and Pole Top Maintenance and Modernization (PTMM)	70,224	83,934	13,709	Company was able to complete more work than forecast
14	Cable Replacement Program	27,452	27,746	294	
15	Frequent Outage Program (CEMI)	55,597	60,067	4,469	Company was able to complete more circuits and additional scope per circuit
16	Breaker Replacement Program	13,576	14,415	839	
17	Pontiac Vaults	1,355	1,263	(92)	
18	URD Replacement Program	6,336	7,043	707	
19	URD Replacement Program: Detroit URD 1-1	1,061	1,154	93	
20	40 kV: Automatic Pole Top Switch	3,419	4,375	956	
21	Disconnect and Switcher Replacement	2,970	4,182	1,212	
22	Steel Pole Highway Crossings	1,935	1,880	(54)	
23	Station Upgrade: Warren (Relay Replacement)	3,183	271	(2,912)	Project was completed in 2021
24	Station Upgrade: Northeast (Relay Replacement)	12,494	13,279	785	
25	Batteries and Chargers Replacement Program	-	2,849	2,849	Moved from the New Load section (previously was under the NRUC and Improvement Blankets)
26	Substation Risk: Hood	-	-	-	
27	Substation Risk: UNVIL 301 B1 Conversion	-	-	-	
28	Portable Generators	-	-	-	
29					
30	Station Upgrade: Lincoln	-	-	-	
31	SCADA Pole Top Device Replacement	584	764	180	
32	Substation Regulator Replacement	422	685	262	
33	Station Upgrade: Navarre	-	-	-	
34	Station Upgrade: 120kV Relays Upgrade for ITC Projects	198	222	24	
35	Substation Risk: Savage Switchgear Replacement	-	-	-	
36	Substation Risk: Seville	-	-	-	
37	Substation Risk: Imlay	-	-	-	
38	Total Infrastructure Resilience and Hardening Projects and Programs	384,109	418,440	34,331	

1/ Variance greater than two million dollars are explained

Michigan Public Service Commission
DTE Electric Company
U-21297 2022 Forecast vs. U-21534 Actuals
Distribution Plant - Infrastructure Redesign and Modernization
(\$000)

Case No.: U-21534
Exhibit: A-23 Revised
Schedule: M1
Witness: A. J. Kryscynski
Page: 5 of 9

(a)		(b)	(c)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2022	U-21534 Actuals 12 mos. ending 12/31/2022	Over / (Under) Forecast	Explanation 1/
1	<u>Infrastructure Redesign and Modernization</u>				
2	Ann Arbor System Improvements: State Substation	6,004	5,996	(7)	
3	Ann Arbor System Improvements: Apex (Blue) Substation	3,489	3,484	(4)	
4	Ann Arbor System Improvements: Argo 40kV Reconfiguration	788	787	(1)	
5	Subtransmission Redesign & Rebuild: Transformer High Side Protection Program	887	1,947	1,060	
6	Subtransmission Redesign & Rebuild: Maxwell Amherst	192	191	(0)	
7	Subtransmission Redesign & Rebuild: Trunk 7106	206	175	(31)	
8	Subtransmission Redesign & Rebuild: Trunk 2255	2,339	2,473	134	
9	Subtransmission Redesign & Rebuild: Trunk 2237-ST	1,051	1,174	123	
10	Subtransmission Redesign & Rebuild: Trunk 7333	1,229	1,300	72	
11	Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker	-	-	-	
12	Subtransmission Redesign & Rebuild: Boyne	14,185	14,072	(114)	
13	Subtransmission Redesign & Rebuild: Tie 4105 Phase 1 2/	8,158	8,226	68	
14	Subtransmission Redesign & Rebuild: Tie 4105 Phase 3 2/	2,392	3,262	869	
15	Subtransmission Redesign & Rebuild: Tie 4105 Phase 4 2/	1,172	2,808	1,637	
16	Subtransmission Redesign & Rebuild: Tie 1568	47	64	17	
17	Subtransmission Redesign & Rebuild: Trunk 4217	300	331	30	
18	Subtransmission Redesign & Rebuild: Trunk 3509	159	126	(34)	
19	Subtransmission Redesign & Rebuild: Trunk 4266	17	3	(14)	
20	Subtransmission Redesign & Rebuild: Praxair	18	-	(18)	
21	Subtransmission Redesign & Rebuild: Small Projects & Reserve	4	-	(4)	
22	Subtransmission Breaker Short Circuit Violations	1,594	1,645	52	
23	Subtransmission Redesign & Rebuild: Slocum	698	125	(572)	
24	Subtransmission Redesign & Rebuild: 40kV Capacitor Banks at Armada and Adair	1,725	2,670	945	
25	Subtransmission Redesign & Rebuild: Oak Beach Capacitor	-	-	-	
26	TCHPP Switchyard Upgrades	-	-	-	
27	Trunk and Tie Lines Hardening Program: Prior Year's	-	(2)	(2)	
28	CODI: Charlotte Network Upgrade	8,286	8,319	33	
29	CODI: Targeted Network Secondary Cable Replacement	1,789	1,987	198	
30	CODI: Corktown Substation	1,360	1,352	(8)	
31	CODI: Islandview Substation - Phase 1 3/	10,118	12,255	2,137	Shifted project scope from 2023 forward to 2022
32	CODI: Islandview Substation - Phase 2 3/	2,774	3,176	402	
33	CODI: Islandview Substation - Phase 3 3/	20	45	25	
34	CODI: Midtown Substation Expansion	2,234	2,283	49	
35	CODI: Alfred Substation Expansion	53	63	10	
36	CODI: Howard Conversion	2	3	1	
37	4.8 kV CC: Cortland / Oakman / Linwood Consolidation	387	241	(146)	
38	4.8 kV CC: Ariel Substation and Circuit Conversion	1,032	1,070	38	
39	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - Below Grade 4/	12,953	13,401	448	
40	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - Above Grade 4/	1,556	2,043	487	
41	4.8 kV CC: Almont Relief and Circuit Conversion (Midas)	12,643	13,119	476	
42	4.8 kV CC: Buckler Circuit Conversion	8,136	8,889	753	
43	4.8 kV CC: McKinstry Sub Decommission	68	38	(31)	
44	4.8 kV CC: Quincy Conversion	1,021	1,052	31	
45	4.8 kV CC: Pinegrove Substation Relocation and Conversion	2,520	2,531	11	
46	4.8 kV CC: Pinegrove Substation Relocation and Conversion CIAC	-	-	-	
47	4.8 kV CC: Hawthorne Relief and Circuit Conversion	402	403	1	
48	4.8 kV CC: Crestwood Substation	23	25	1	

Michigan Public Service Commission
DTE Electric Company
U-21297 2022 Forecast vs. U-21534 Actuals
Distribution Plant - Infrastructure Redesign and Modernization
(\$000)

Case No.: U-21534
Exhibit: A-23 Revised
Schedule: M1
Witness: A. J. Kryscynski
Page: 6 of 9

(a)		(b)	(c)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2022	U-21534 Actuals 12 mos. ending 12/31/2022	Over / (Under) Forecast	Notes 1/
49	4.8 kV CC: MAUME 8241 Downtown Clawson Conversion	2,638	2,603	(36)	
50	4.8 kV CC: Power line Conversion of MADSN 175L-W	123	107	(15)	
51	4.8 kV CC: GRFIN & WMSTN Conversions	508	136	(372)	
52	4.8kV CC: SCOTN	49	50	0	
53	4.8 kV CC: Slater	1,930	1,930	-	
54	4.8 kV CC: Royal Oak Substation and Circuit Conversion	-	-	-	
55	4.8 kV CC: Curtis	-	-	-	
56	4.8 kV CC: Unionville DC 301 B1 Conversion	-	-	-	
57	System Loading: Brest Substation	-	(2)	(2)	
58	System Loading: Carleton	376	336	(40)	
59	System Loading: Grayling	-	-	-	
60	System Loading: Prospect	-	(146)	(146)	
61	System Loading: Mandy 307 Load Transfer	24	1	(23)	
62	System Loading: Mack Transformer 102	54	32	(22)	
63	System Loading: Globe	-	-	-	
64	Pilot: Strategic and Service Undergrounding	454	462	7	
65	Pilot: Primary Deconductoring	1,848	1,846	(2)	
66	Subtransmission Redesign & Rebuild: Tie 810	9,100	8,832	(268)	
67	Subtransmission Redesign & Rebuild: Tie 7504	14	93	79	
68	Subtransmission Redesign & Rebuild: Tie 4105 Phase 2	2/ 945	896	(49)	
69	Subtransmission Redesign & Rebuild: Tie 4105 Phase 5	2/ 305	322	17	
70	Subtransmission Redesign & Rebuild: Trunk 2308	51	53	2	
71	Subtransmission Redesign & Rebuild: Tie 3205	17	96	79	
72	Subtransmission Redesign & Rebuild: Reverse Power Relay Scheme Program	-	-	-	
73	Subtransmission Redesign & Rebuild: Tie 4104	106	134	28	
74	Subtransmission Redesign & Rebuild: Badax Transformer 102 Addition	611	284	(326)	
75	Subtransmission Redesign & Rebuild: Trunk 4245	8	15	7	
76	Subtransmission Redesign & Rebuild: Trunk 4911	44	139	95	
77	Subtransmission Redesign & Rebuild: Custer Republic	-	-	-	
78	Subtransmission Redesign & Rebuild: Cortland Station Expansion	908	897	(11)	
79	CODI: CATO Substation Expansion	319	290	(28)	
80	CODI: Garfield Radial (Midtown Circuits)	5/ -	415	415	
81	CODI: Garfield Network Upgrade	5/ 18,193	17,430	(763)	
82	CODI: Kent/Gibson Conversion - Phase 1	6/ 2,051	2,186	135	
83	4.8 kV CC: Zenon Substation and Circuit Conversion	1	1	-	
84	4.8 kV CC: Calla Circuit Conversion and Phase 2	65	65	-	
85	4.8 kV CC: Lapeer - Elba Expansion and Circuit Conversion (Apollo)	2,710	2,728	18	
86	4.8 kV CC: Birmingham Decommissioning and Circuit Conversion	1	2	1	
87	4.8 kV CC: ISO Conversion Program	33	52	19	
88	4.8 kV CC: Hemlock Decommissioning and Circuit Conversion	-	-	-	
89	4.8 kV CC: White Lake Decommissioning and Circuit Conversion	-	0	0	
90	8.3 kV CC: Pontiac Overhead Conversion	3,016	3,446	430	
91	8.3 kV CC: Pontiac Underground Conversion	702	747	45	
92	System Loading: Brown City	44	(28)	(73)	
93	System Loading: Port Sanilac	35	15	(20)	
94	System Loading: Richmond/Armada	1,164	3,201	2,037	Shifted purchase of substation transformer from 2023 to 2022
95	System Loading: Cody	-	-	-	
96	System Loading: Otsego/Capac/Shaw	-	-	-	
97	System Loading: Macomb/Golf	-	-	-	

Michigan Public Service Commission
DTE Electric Company
U-21297 2022 Forecast vs. U-21534 Actuals
Distribution Plant - Infrastructure Redesign and Modernization
(\$000)

Case No.: U-21534
Exhibit: A-23 Revised
Schedule: M1
Witness: A. J. Kryscynski
Page: 7 of 9

(a)		(b)	(c)	(c)	(d)
Line		U-21297 Forecast	U-21534 Forecast	Over / (Under)	
No.	Description	12 mos. ending 12/31/2022	12 mos. ending 12/31/2022	Forecast	Explanation 1/
98	System Loading: Grenada	185	225	40	
99	System Loading: Lark/Spruce	12	14	2	
100	System Loading: Jewell	-	-	-	
101	System Loading: Mayville	-	-	-	
102	System Loading: Goodison	-	-	-	
103	System Loading: Wixom	-	-	-	
104	System Loading: Diamond	-	-	-	
105	System Loading: Spokane/Seneca	-	-	-	
106	System Loading: Sterling	-	-	-	
107	System Loading: Disco	-	-	-	
108	System Loading: Tahoe	-	-	-	
109	System Loading: New Baltimore/Chesterfield	-	-	-	
110	System Loading: Kings Point	-	-	-	
111	Subtransmission Redesign & Rebuild: Tie 6907	-	-	-	
112	Subtransmission Redesign & Rebuild: Tie 6602	-	-	-	
113	Subtransmission Redesign & Rebuild: Trunk 2419	-	-	-	
114	Subtransmission Redesign & Rebuild: Kennett	-	-	-	
115	Subtransmission Redesign & Rebuild: Trunk 4601	-	-	-	
116	Subtransmission Redesign & Rebuild: Tempest Phase II	-	-	-	
117	Subtransmission Redesign & Rebuild: Waterman	-	-	-	
118	Subtransmission Redesign & Rebuild: Trunk 7105	-	-	-	
119	Subtransmission Redesign & Rebuild: Tie 5208	-	-	-	
120	4.8 kV CC: Hilton Substation and Circuit Conversion	-	-	-	
121	4.8 kV CC: Hawthorne Trf #2 and Secondary Cable Replacement	59	-	(59)	
122	4.8kV CC: Rochester Decommissioning and Tienken Relief	-	-	-	
123	4.8 kV CC: Ann Arbor AC Network Conversion	-	-	-	
124	4.8kV CC: Pittsfield Substation and Circuit Conversion	-	-	-	
125	4.8kV CC: Yale-Slater Decommissioning and Circuit Conversion	-	-	-	
126	4.8 kV CC: Grosse Pointe Substation and Circuit Conversion	-	-	-	
127	Total Infrastructure Redesign and Modernization Projects and Programs	162,735	173,059	10,324	

1/ Variance greater than two million dollars are explained
2/ Tie 4105 phases on lines 13-15 and 68-69 were collectively "Subtransmission Redesign & Rebuild: Tie 4105" in U-21297 (Exh A-12, Sch B5.4, pg. 9, Line 17). Tie 4105 was forecasted at \$12,971 compared to actuals of \$15,514.
3/ CODI: Islandview Substation phases on lines 31-33 were collectively "CODI: Islandview Substation" in U-21297 (Exh A-12, Sch B5.4, pg. 10, Line 45). Islandview was forecasted at \$12,912 compared to actuals of \$15,477.
4/ Promenade phases on lines 39-40 were collectively "4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade)" in U-21297 (Exh A-12, Sch B5.4, pg. 10, Line 56). Promenade was forecasted at \$14,509 compared to actuals of 15,444.
5/ CODI: Garfield projects on lines 80-81 were collectively "CODI: Garfield Network Upgrade" in U-21297 (Exh A-12, Sch B5.4, pg. 10, Line 50). CODI: Garfield was forecasted \$18,193 in U-21297 compared to \$17,845 in U-21534.
6/ CODI: Kent/Gibson Conversion - Phase 1 on line 82 was "CODI: Kent/Gibson Conversion" in U-21297 (Exh A-12, Sch B5.4, pg. 10, Line 51).

Michigan Public Service Commission
DTE Electric Company
U-21297 2022 Forecast vs. U-21534 Actuals
Distribution Plant - Technology and Automation
(\$000)

Case No.: U-21534
Exhibit: A-23 Revised
Schedule: M1
Witness: A. J. Kryscynski
Page: 8 of 9

(a)		(b)	(c)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2022	U-21534 Actuals 12 mos. ending 12/31/2022	Over / (Under) Forecast	Explanation 1/
1	<u>Technology and Automation</u>				
2	Distribution Automation	2/ 5,117	5,506	389	
3	ADMS: DMS/OMS	28,165	28,961	796	
4	SOC: ESOC	1,420	1,250	(170)	
5	SOC: ASOC	7,046	7,534	488	
6	Grid Automation Telecommunications	14,206	16,328	2,122	2023 scope pulled ahead to purchase material and prevent supply chain delays
7	Distribution Sensing and Monitoring (inclgd Line Sensors)	1,523	862	(660)	
8	CVR/VVO	4,912	5,164	252	
9	NWA: O'Shea Energy Storage	1,067	1,456	389	
10	NWA: Battery Trailer	949	2,051	1,101	
11	NWA: Omega Load Relief	2,197	4,464	2,266	Specific battery trailer components and the associated labor for installation
12	NWA: Fisher Load Relief	77	66	(11)	
13	NWA: Port Austin Load Relief	598	619	21	
14	NWA: Small Solar and Storage Testbed	337	335	(3)	
15	Sensor, Network and Algorithm Development (Solar Deployment)	96	218	122	
16	Technology Programs & NWA	0	0	-	
17	AMI: Meter Communications Upgrades	626	631	5	
18	Customer Power Status Visibility	-	-	-	
19	SCADA Remote Access and Configuration Platform	453	1,164	711	
20	Substation Reporting and Process Enhancements	-	-	-	
21	Asset Management Upgrades	668	1,711	1,043	
22	Systematic Tracking of Rotatable Assets	-	-	-	
23	External Crew Efficiency	-	-	-	
24	Tree Trim Risk Prioritization Model	-	3,078	3,078	Investment was split between IT and DO. Further detailed provided by Company Witness Kryscynski
25	NWA: Veridian	387	360	(28)	
26	NWA: Adaptive Networked Microgrids	-	-	-	
27	NWA: Adaptive Networked Microgrids - Project Contributions	-	-	-	
28	NWA: EV Charging Demonstration at ACM	1,231	1,292	60	
29	Interconnection Process Enablement	1,950	4,776	2,825	Timing of investment for interconnection gateway platform development moved ahead
30	Grid Edge Insights & New Technology	1,801	2,288	487	
31	DER Control	-	-	-	
32	ADMS Enhancements	-	-	-	
33	Operational Technology and Error Free Communication	5,898	5,496	(402)	
34	Meter Improvements	-	-	-	
35	FLISR Implementation	-	-	-	
36	DERMS	-	-	-	
37	Substation Cybersecurity	787	618	(170)	
38	Automation Configuration and Test Record Database	(43)	(115)	(72)	
39	Microwave End of Life	259	-	(259)	
40	Other Modernize Grid Management	4,772	7,807	3,036	See Witness Hartwick's testimony
41	ADMS: Network Management System	1,328	2,071	744	
42	Load Forecasting & Analytics	2,536	2,737	201	
43	Hosting Capacity Enablement	49	108	59	
44	Power Quality Analysis Program	-	-	-	
45	Substation Design Tool Upgrades	262	552	290	
46	Distribution Planning	-	932	932	
47	Enhance Maximo Capabilities and Processes	-	-	-	

Michigan Public Service Commission
DTE Electric Company
U-21297 2022 Forecast vs. U-21534 Actuals
Distribution Plant - Technology and Automation
(\$000)

Case No.: U-21534
Exhibit: A-23 Revised
Schedule: M1
Witness: A. J. Kryscynski
Page: 9 of 9

(a)		(b)	(c)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2022	U-21534 Actuals 12 mos. ending 12/31/2022	Over / (Under) Forecast	Notes 1/
48	Primary Service Orders Replatform	-	-	-	
49	Work Management & Scheduling Upgrades	6,160	12,155	5,995	New tools supporting field and storm processes
50	Mobile tools expansion	-	-	-	
51	Maintain compliance	-	-	-	
52	Enhance and expand cybersecurity	-	-	-	
53	Mobile Equipment Replacement	-	-	-	
54	Mobile Technology	990	969	(21)	
55	SCADA / AMI Enhancements	450	-	(450)	
56	Total Technology and Automation Projects and Programs	98,276	123,441	25,164	

1/ Variance greater than two million dollars are explained
2/ Distribution Automation is collectively "Automation: Substation", "Automation: 13.2kV Circuit Distributions", and "4.8 kV Circuit Automation" in U-21297 (See Exh A-12, Sch B5.4, pg. 12 Line 9, 10, and 39, respectively)

Michigan Public Service Commission
DTE Electric Company
U-21297 vs.U-21534 2023 Forecast Comparison
Distribution Plant
(\$000)

Case No.: U-21534
Exhibit: A-23 Revised
Schedule: M2
Witness: A. J. Kryscynski
Page: 1 of 9

Line No.	(a) Description	(b) U-21297 Forecast 12 mos. ending 12/31/2023	(c) U-21534 Forecast 12 mos. ending 12/31/2023	(c) Over / (Under)	
				Forecast	Percentage
1	Base Capital Programs				
2	Emergent Replacements				
3	Storm	220,576	281,848	61,272	28%
4	Non - Storm	183,074	207,192	24,118	13%
5	Substation Reactive	45,969	42,217	(3,752)	-8%
6	Emergent Replacement Reduction Based on Strategic Spend	(14,285)	-	14,285	-100%
7	Subtotal Emergent Replacements	435,335	531,257	95,922	22%
8	Customer Connections, Relocations & Other				
9	Connections and New Load	197,614	216,938	19,324	10%
10	Relocations	25,773	45,774	20,001	78%
11	Electric System Equipment	29,289	33,655	4,366	15%
12	NRUC and Improvement Blankets	22,401	19,531	(2,870)	-13%
13	General Plant, Tools & Equipment and Miscellaneous	6,622	5,886	(736)	-11%
14	Public Lighting Department Project	2,400	1,920	(480)	
15	Subtotal Customer Connections, Relocations & Other	284,099	323,703	39,605	14%
16	Customer Advances for Construction	(27,153)	(22,786)	4,367	-16%
17	Total Base Capital Programs	692,281	832,175	139,894	20%
13					
14	Strategic Capital Programs				
15	Infrastructure Resilience and Hardening	333,807	376,177	42,370	13%
16	Infrastructure Redesign and Modernization	341,094	259,244	(81,850)	-24%
17	Technology and Automation	136,604	165,605	29,001	21%
18	Subtotal Strategic Capital Programs	811,505	801,026	(10,479)	-1%
19					
20	Total Capital	1,503,786	1,633,201	129,415	9%

Michigan Public Service Commission
DTE Electric Company
U-21297 vs.U-21534 2023 Forecast Comparison
Distribution Plant - Connections, Relocations and Other
(\$000)

Case No.: U-21534
Exhibit: A-23
Schedule: M2
Witness: A. J. Kryscynski
Page: 2 of 9

(a)		(b)	(c)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2023	U-21534 Forecast 12 mos. ending 12/31/2023	Over / (Under) Forecast	Explanation 1/
1	<u>Connections and New Load</u>				
2	Projected Small Load Growth Projects (Blanket)	23,159	18,026	(5,133)	
3					
4	Projected Customer Connections	116,335	123,306	6,971	
5	Projected Customer Connections CIAC	<u>(16,598)</u>	<u>(16,782)</u>	<u>(184)</u>	
6	Projected Customer Connections (Net of CIAC)	99,737	106,524	6,787	
7					
8	Projected New Business Projects	58,120	75,606	17,486	
9	Projected New Business Projects CIAC	<u>(10,039)</u>	<u>(5,847)</u>	<u>4,192</u>	
10	Projected New Business Projects (net of CIAC)	48,081	69,759	21,678	
11					
12	Incremental Infrastructure for EV	<u>-</u>	<u>-</u>	<u>-</u>	
13					
14	Total Connections and New Load	197,614	216,938	19,324	
15	Total Connections and New Load CIAC	<u>(26,637)</u>	<u>(22,629)</u>	<u>4,008</u>	
16	Total Connections and New Load (Net of CIAC)	170,977	194,309	23,332	Higher than forecast customer demand in 2023
17					
18	<u>Relocations</u>				
19	Projected Small Relocation Projects (Blanket)	7,503	7,787	283	
20					
21	Major Infrastructure Relocation Project				
22	Gordie Howe International Bridge	-	-	-	
23	I-375 Relocations	-	5,938	5,938	New project requested by MDOT to relocate distribution infrastructure under I-375
24					
25	Relocation Projects (excl. Major Infrastructure Projects)	18,270	32,050	13,780	More work completed than forecast
26	Relocation Projects CIAC	<u>(516)</u>	<u>(157)</u>	<u>359</u>	
27	Subtotal Relocation Projects (Net of CIAC)	17,754	31,893	14,139	
28					
29	Total Relocations	25,773	45,774	20,001	
30	Total Relocations CIAC	<u>(516)</u>	<u>(157)</u>	<u>359</u>	
31	Total Relocations (Net of CIAC)	25,257	45,618	20,360	
32					
33	Electric System Equipment				
34	Distribution Transformers & Regulators	-	5,586	5,586	
35	Projected Major Equipment	14,534	12,748	(1,787)	
36	Projected Meters	<u>14,755</u>	<u>15,321</u>	<u>566</u>	
37	Total Electric System Equipment	29,289	33,655	4,366	
38					
39	NRUC and Improvement Blankets				
40	Projected System Improvements	10,387	7,797	(2,590)	
41	Projected Normal Retirement Unit Changeouts (NRUC)	6,096	4,432	(1,664)	
42	Projected Operational Technologies	<u>5,918</u>	<u>7,301</u>	<u>1,384</u>	
43	Total NRUC and Improvement Blankets	22,401	19,531	(2,870)	
44					
45	General Plant, Tools & Equipment and Miscellaneous				
46	Projected Substation Physical Security	536	544	9	
47	Projected General Plant, Tools & Equipment and Miscellaneous	<u>6,086</u>	<u>5,342</u>	<u>(744)</u>	
48	Total General Plant, Tools & Equipment and Miscellaneous	6,622	5,886	(736)	

Michigan Public Service Commission
DTE Electric Company
U-21297 vs.U-21534 2023 Forecast Comparison
Distribution Plant - Connections, Relocations and Other
(\$000)

Case No.: U-21534
Exhibit: A-23
Schedule: M2
Witness: A. J. Kryscynski
Page: 3 of 9

(a)		(b)	(c)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2023	U-21534 Forecast 12 mos. ending 12/31/2023	Over / (Under) Forecast	Explanation 1/
49					
50	Public Lighting Department Project	2,400	1,920	(480)	
51					
52	Total Customer Connections, Relocations & Other	284,099	323,703	39,604	
53	Total Cust Connections, Relocations & Other CIAC	(27,153)	(22,786)	4,367	
54	Total Cust Connections, Relocations & Other Net of CIAC	256,946	300,918	43,972	

1/ Variance greater than two million dollars are explained

Michigan Public Service Commission
DTE Electric Company
U-21297 vs.U-21534 2023 Forecast Comparison
Distribution Plant - Infrastructure Resilience and Hardening
(\$000)

Case No.: U-21534
Exhibit: A-23
Schedule: M2
Witness: A. J. Kryscynski
Page: 4 of 9

Line No.	(a) Description	(b)	(c)	(c)	(d)
		U-21297 Forecast 12 mos. ending 12/31/2023	U-21534 Forecast 12 mos. ending 12/31/2023	Over / (Under) Forecast	Explanation 1/
1	<u>Infrastructure Resilience and Hardening</u>				
2	Mobile Fleet Program	5,305	2,804	(2,501)	Delays in (1) obtaining materials and (2) rebuild unit work
3	Substation Risk: Drexel	268	640	373	
4	Substation Risk: Chestnut	3,715	989	(2,725)	Project delayed due to design
5	Substation Risk: Savage	2	11	9	
6	Substation Risk: Apache	11,628	8,492	(3,136)	Delay due to permit and obtaining circuit switchers
7	Substation Risk: Port Huron	-	3	3	
8	Substation Risk: Belleville Switchgear Decommission	1,006	1,313	308	
9	Substation Risk: McGraw	29,714	6,310	(23,405)	Land acquisition and design delays
10	Substation Risk: Voyager	-	2	2	
11	Substation Risk: Flood Defense Program	5,800	269	(5,531)	Delays due to design and vendor contract negotiations
12	4.8 kV Hardening	80,000	127,010	47,010	Company was able to complete more work than forecast
13	Pole and Pole Top Maintenance and Modernization (PTMM)	63,445	79,075	15,629	Company was able to complete more work than forecast
14	Cable Replacement Program	24,870	22,832	(2,039)	Delays due to safety hazards
15	Frequent Outage Program (CEMI)	55,252	63,963	8,711	More work completed in the Customer Excellence program
16	Breaker Replacement Program	13,177	13,161	(16)	
17	Pontiac Vaults	58	657	599	
18	URD Replacement Program	13,750	12,417	(1,333)	
19	URD Replacement Program: Detroit URD 1-1	-	285	285	
20	40 kV: Automatic Pole Top Switch	6,325	6,358	33	
21	Disconnect and Switcher Replacement	4,900	15,457	10,557	Trenton Channel Power Plant (\$2.7M) and River Rouge Power Plant (\$5.9) Switchyard Upgrades; Investment was include in U-21297 (Exh A-12, Sch B5.1, page 2, Line 32 and 37)
22	Steel Pole Highway Crossings	3,000	1,734	(1,266)	
23	Station Upgrade: Warren (Relay Replacement)	-	649	649	
24	Station Upgrade: Northeast (Relay Replacement)	2,417	3,652	1,235	
25	Batteries and Chargers Replacement Program	2,500	3,343	843	
26	Substation Risk: Hood	-	249	249	
27	Substation Risk: UNVIL 301 B1 Conversion	-	112	112	
28	Portable Generators	-	-	-	
29		-	-		
30	Station Upgrade: Lincoln	330	-	(330)	
31	SCADA Pole Top Device Replacement	1,611	1,694	83	
32	Substation Regulator Replacement	894	1,337	442	
33	Station Upgrade: Navarre	-	-	-	
34	Station Upgrade: 120kV Relays Upgrade for ITC Projects	3,839	1,359	(2,481)	Project deferrals requested by ITC, deferred to 2024
35	Substation Risk: Savage Switchgear Replacement	-	-	-	
36	Substation Risk: Seville	-	-	-	
37	Substation Risk: Imlay	-	-	-	
38	Total Infrastructure Resilience and Hardening Projects and Programs	333,807	376,177	42,370	

1/ Variance greater than two million dollars are explained

Michigan Public Service Commission
DTE Electric Company
U-21297 vs.U-21534 2023 Forecast Comparison
Distribution Plant - Infrastructure Redesign and Modernization
(\$000)

Case No.: U-21534
Exhibit: A-23
Schedule: M2
Witness: A. J. Kryscynski
Page: 5 of 9

(a)		(b)	(c)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2023	U-21534 Forecast 12 mos. ending 12/31/2023	Over / (Under) Forecast	Explanation 1/
1	<u>Infrastructure Redesign and Modernization</u>				
2	Ann Arbor System Improvements: State Substation	1,608	2,543	936	
3	Ann Arbor System Improvements: Apex (Blue) Substation	1,933	1,478	(455)	
4	Ann Arbor System Improvements: Argo 40kV Reconfiguration	7,920	334	(7,586)	Work dependent upon load transferring from Argo to new substation to commence this project scope
5	Subtransmission Redesign & Rebuild: Transformer High Side Protection Program	5,500	2,477	(3,023)	Projects shifted from 2023 to 2024 due to customer delays or inability to shutdown equipment to perform work
6	Subtransmission Redesign & Rebuild: Maxwell Amherst	-	160	160	
7	Subtransmission Redesign & Rebuild: Trunk 7106	-	(90)	(90)	
8	Subtransmission Redesign & Rebuild: Trunk 2255	34	698	664	
9	Subtransmission Redesign & Rebuild: Trunk 2237-ST	-	207	207	
10	Subtransmission Redesign & Rebuild: Trunk 7333	-	168	168	
11	Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker	4,283	67	(4,216)	Clearance limitations complicated design and delays in developing shutdown plan
12	Subtransmission Redesign & Rebuild: Boyne	7,037	8,309	1,272	
13	Subtransmission Redesign & Rebuild: Tie 4105 Phase 1 2/	1,271	1,448	177	
14	Subtransmission Redesign & Rebuild: Tie 4105 Phase 3 2/	6,158	13,753	7,595	Increased scope and materials due to field conditions and co-location with Thumb Electric Co-op
15	Subtransmission Redesign & Rebuild: Tie 4105 Phase 4 2/	1,941	-	(1,941)	
16	Subtransmission Redesign & Rebuild: Tie 1568	688	645	(43)	
17	Subtransmission Redesign & Rebuild: Trunk 4217	4,865	1,921	(2,944)	Project delayed due to material shortage and adjacent hazards in manholes
18	Subtransmission Redesign & Rebuild: Trunk 3509	1,184	2,284	1,099	
19	Subtransmission Redesign & Rebuild: Trunk 4266	270	-	(270)	
20	Subtransmission Redesign & Rebuild: Praxair	2,767	-	(2,767)	Project being re-designed and moved to 2025
21	Subtransmission Redesign & Rebuild: Small Projects & Reserve	34	4	(30)	
22	Subtransmission Breaker Short Circuit Violations	1,414	2,864	1,450	
23	Subtransmission Redesign & Rebuild: Slocum	737	511	(226)	
24	Subtransmission Redesign & Rebuild: 40kV Capacitor Banks at Armada and Adair	950	2,717	1,767	
25	Subtransmission Redesign & Rebuild: Oak Beach Capacitor	-	-	-	
26	TCHPP Switchyard Upgrades	-	2,334	2,334	
27	Trunk and Tie Lines Hardening Program: Prior Year's	-	-	-	
28	CODI: Charlotte Network Upgrade	6,658	8,727	2,069	Additional URD system conduit work, OH work shifted from 2022 to 2023 for cross arm design change
29	CODI: Targeted Network Secondary Cable Replacement	3,800	4,294	494	
30	CODI: Corktown Substation	-	100	100	
31	CODI: Islandview Substation - Phase 1 3/	7,027	7,734	707	
32	CODI: Islandview Substation - Phase 2 3/	27,363	35,847	8,484	Shifted pre-conversion overhead work from 2024 to 2023 and additional material required for secondary work
33	CODI: Islandview Substation - Phase 3 3/	1,355	-	(1,355)	
34	CODI: Midtown Substation Expansion	1,803	1,085	(717)	
35	CODI: Alfred Substation Expansion	4,137	3,183	(955)	
36	CODI: Howard Conversion	700	-	(700)	
37	4.8 kV CC: Cortland / Oakman / Linwood Consolidation	-	737	737	
38	4.8 kV CC: Ariel Substation and Circuit Conversion	600	641	41	
39	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - Below Grade 4/	2,530	2,174	(356)	
40	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - Above Grade 4/	5,662	4,204	(1,458)	
41	4.8 kV CC: Almont Relief and Circuit Conversion (Midas)	3,565	3,944	379	
42	4.8 kV CC: Buckler Circuit Conversion	2,865	3,882	1,018	
43	4.8 kV CC: McKinstry Sub Decommission	4,628	559	(4,069)	Construction delayed due to dependency for Waterman as built drawings
44	4.8 kV CC: Quincy Conversion	2,338	1,667	(670)	
45	4.8 kV CC: Pinegrove Substation Relocation and Conversion	43,760	20,626	(23,134)	Unidentified oil pipe in conduit route resulted in redesign, additional scope; delay in substation property
46	4.8 kV CC: Pinegrove Substation Relocation and Conversion CIAC	(15,300)	95	15,395	CIAC shifted from 2023 to 2024
47	4.8 kV CC: Hawthorne Relief and Circuit Conversion	6,000	-	(6,000)	U-21534 forecast is zero as project being considered for the IRM; Project scope reduced by 1/3
48	4.8 kV CC: Crestwood Substation	-	640	640	

Michigan Public Service Commission
DTE Electric Company
U-21297 vs.U-21534 2023 Forecast Comparison
Distribution Plant - Infrastructure Redesign and Modernization
(\$000)

Case No.: U-21534
Exhibit: A-23
Schedule: M2
Witness: A. J. Kryscynski
Page: 6 of 9

(a)		(b)	(c)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2023	U-21534 Forecast 12 mos. ending 12/31/2023	Over / (Under) Forecast	Notes
49	4.8 kV CC: MAUME 8241 Downtown Clawson Conversion	3	25	21	
50	4.8 kV CC: Power line Conversion of MADSN 175L-W	238	578	340	
51	4.8 kV CC: GRFIN & WMSTN Conversions	4,145	2,218	(1,927)	
52	4.8kV CC: SCOTN	2,710	1,174	(1,536)	
53	4.8 kV CC: Slater	-	4	4	
54	4.8 kV CC: Royal Oak Substation and Circuit Conversion	2,000	652	(1,348)	
55	4.8 kV CC: Curtis	-	17	17	
56	4.8 kV CC: Unionville DC 301 B1 Conversion	-	-	-	
57	System Loading: Brest Substation	-	-	-	
58	System Loading: Carleton	28	187	159	
59	System Loading: Grayling	-	-	-	
60	System Loading: Prospect	-	-	-	
61	System Loading: Mandy 307 Load Transfer	-	(82)	(82)	
62	System Loading: Mack Transformer 102	8	10	2	
63	System Loading: Globe	500	-	(500)	
64	Pilot: Strategic and Service Undergrounding	2,100	3,830	1,730	
65	Pilot: Primary Deconductoring	-	36	36	
66	Subtransmission Redesign & Rebuild: Tie 810	20,000	21,771	1,771	
67	Subtransmission Redesign & Rebuild: Tie 7504	1,628	3,263	1,635	
68	Subtransmission Redesign & Rebuild: Tie 4105 Phase 2	2/ 10,542	-	(10,542)	U-21534 forecast is zero as project being considered for the IRM; Delayed due to property purchase
69	Subtransmission Redesign & Rebuild: Tie 4105 Phase 5	2/ 37	-	(37)	
70	Subtransmission Redesign & Rebuild: Trunk 2308	7,244	3,224	(4,020)	Design delayed due to change from contractor to internal resources; Construction stopped due to license delay
71	Subtransmission Redesign & Rebuild: Tie 3205	500	791	291	
72	Subtransmission Redesign & Rebuild: Reverse Power Relay Scheme Program	-	-	-	
73	Subtransmission Redesign & Rebuild: Tie 4104	1,004	-	(1,004)	
74	Subtransmission Redesign & Rebuild: Badax Transformer 102 Addition	7,820	1,677	(6,142)	Project being re-scoped; construction to start in late 2024
75	Subtransmission Redesign & Rebuild: Trunk 4245	3,059	703	(2,356)	Manhole and conduit inspections found collapse duct, construction delayed due to adjacent hazards
76	Subtransmission Redesign & Rebuild: Trunk 4911	894	-	(894)	
77	Subtransmission Redesign & Rebuild: Custer Republic	159	-	(159)	
78	Subtransmission Redesign & Rebuild: Cortland Station Expansion	343	40	(303)	
79	CODI: CATO Substation Expansion	10,795	3,139	(7,656)	Scope changes due to adjacent hazards and asbestos removal and additional relay design requirements
80	CODI: Garfield Radial (Midtown Circuits)	5/ 8,599	2,153	(6,446)	Refined design scope and estimate, which shifted construction start from 2023 to 2024
81	CODI: Garfield Network Upgrade	5/ 21,401	23,390	1,989	
82	CODI: Kent/Gibson Conversion - Phase 1	6/ 19,810	8,845	(10,965)	Easement and permit issues impacting design timeline and generator not needed
83	4.8 kV CC: Zenon Substation and Circuit Conversion	-	-	-	
84	4.8 kV CC: Calla Circuit Conversion and Phase 2	17	-	(17)	
85	4.8 kV CC: Lapeer - Elba Expansion and Circuit Conversion (Apollo)	8,682	947	(7,735)	Materials shifted to a project further along; Substation work shifted from 2023 to 2024
86	4.8 kV CC: Birmingham Decommissioning and Circuit Conversion	1,501	906	(595)	
87	4.8 kV CC: ISO Conversion Program	7,000	6,466	(534)	
88	4.8 kV CC: Hemlock Decommissioning and Circuit Conversion	158	152	(5)	
89	4.8 kV CC: White Lake Decommissioning and Circuit Conversion	-	-	-	
90	8.3 kV CC: Pontiac Overhead Conversion	12,420	9,929	(2,491)	Road restoration lower than forecast
91	8.3 kV CC: Pontiac Underground Conversion	1,208	1,197	(11)	
92	System Loading: Brown City	4,685	2,485	(2,200)	Project was on hold due to customer easement dispute
93	System Loading: Port Sanilac	303	438	135	
94	System Loading: Richmond/Armada	6,351	8,417	2,066	Shifted purchase of substation transformer from 2023 to 2022
95	System Loading: Cody	461	384	(78)	
96	System Loading: Otsego/Capac/Shaw	396	151	(245)	
97	System Loading: Macomb/Golf	-	-	-	

Michigan Public Service Commission
DTE Electric Company
U-21297 vs.U-21534 2023 Forecast Comparison
Distribution Plant - Infrastructure Redesign and Modernization
(\$000)

Case No.: U-21534
Exhibit: A-23
Schedule: M2
Witness: A. J. Kryscynski
Page: 7 of 9

(a)		(b)	(c)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2023	U-21534 Forecast 12 mos. ending 12/31/2023	Over / (Under) Forecast	Notes
98	System Loading: Grenada	2,105	3,521	1,416	
99	System Loading: Lark/Spruce	44	24	(20)	
100	System Loading: Jewell	-	1,265	1,265	
101	System Loading: Mayville	-	-	-	
102	System Loading: Goodison	-	-	-	
103	System Loading: Wixom	500	72	(428)	
104	System Loading: Diamond	-	-	-	
105	System Loading: Spokane/Seneca	116	62	(54)	
106	System Loading: Sterling	95	-	(95)	
107	System Loading: Disco	43	75	32	
108	System Loading: Tahoe	25	-	(25)	
109	System Loading: New Baltimore/Chesterfield	-	-	-	
110	System Loading: Kings Point	-	135	135	
111	Subtransmission Redesign & Rebuild: Tie 6907	426	-	(426)	
112	Subtransmission Redesign & Rebuild: Tie 6602	660	-	(660)	
113	Subtransmission Redesign & Rebuild: Trunk 2419	169	-	(169)	
114	Subtransmission Redesign & Rebuild: Kennett	437	-	(437)	
115	Subtransmission Redesign & Rebuild: Trunk 4601	214	-	(214)	
116	Subtransmission Redesign & Rebuild: Tempest Phase II	970	-	(970)	
117	Subtransmission Redesign & Rebuild: Waterman	103	-	(103)	
118	Subtransmission Redesign & Rebuild: Trunk 7105	61	-	(61)	
119	Subtransmission Redesign & Rebuild: Tie 5208	50	-	(50)	
120	4.8 kV CC: Hilton Substation and Circuit Conversion	-	-	-	
121	4.8 kV CC: Hawthorne Trf #2 and Secondary Cable Replacement	1,790	-	(1,790)	
122	4.8kV CC: Rochester Decommissioning and Tienken Relief	104	-	(104)	
123	4.8 kV CC: Ann Arbor AC Network Conversion	135	-	(135)	
124	4.8kV CC: Pittsfield Substation and Circuit Conversion	178	-	(178)	
125	4.8kV CC: Yale-Slater Decommissioning and Circuit Conversion	269	-	(269)	
126	4.8 kV CC: Grosse Pointe Substation and Circuit Conversion	2,000	-	(2,000)	
127	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - System Conduit 4/	1,418	-	(1,418)	
128	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - Phase 4 4/	349	-	(349)	
129	Total Infrastructure Redesign and Modernization Projects and Programs	341,094	259,244	(81,850)	

1/ Variance greater than two million dollars are explained

2/ Tie 4105 phases on lines 13-15 and 68-69 were collectively "Subtransmission Redesign & Rebuild: Tie 4105" in U-21297 (Exh A-12, Sch B5.4, pg. 9, Line 17). Tie 4105 was forecasted at \$19,949 in U-21297 compared to \$15,201 in U-21534.

3/ CODI: Islandview Substation phases on lines 31-33 were collectively "CODI: Islandview Substation" in U-21297 (Exh A-12, Sch B5.4, pg. 10, Line 45). Islandview was forecasted at \$35,745 in U-21297 compared to \$43,581 in U-21534.

4/ Promenade phases on lines 39-40 and 127-128 were collectively "4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade)" in U-21297 (Exh A-12, Sch B5.4, pg. 10, Line 56). Promenade was forecasted at \$9,959 in U-21297 compared to \$6,378 in U-21534.

5/ CODI: Garfield projects on lines 80-81 were collectively "CODI: Garfield Network Upgrade" in U-21297 (Exh A-12, Sch B5.4, pg. 10, Line 50). CODI: Garfield was forecasted \$30,000 in U-21297 compared to \$25,543 in U-21534.

6/ CODI: Kent/Gibson Conversion - Phase 1 on line 82 was "CODI: Kent/Gibson Conversion" in U-21297 (Exh A-12, Sch B5.4, pg. 10, Line 51).

(a)		(b)	(c)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2023	U-21534 Forecast 12 mos. ending 12/31/2023	Over / (Under) Forecast	Explanation 1/
1	<u>Technology and Automation</u>				
2	Distribution Automation	2/ 23,042	27,104	4,063	Company was able to execute work at a faster pace then planned, scope was pulled ahead from 2024
3	ADMS: DMS/OMS	10,840	9,270	(1,570)	
4	SOC: ESOC	200	-	(200)	
5	SOC: ASOC	27,100	20,927	(6,173)	Technology and interior construction work will continue into the second quarter of 2024
6	Grid Automation Telecommunications	19,100	21,346	2,246	Scope was pulled ahead from 2024
7	Distribution Sensing and Monitoring (incldg Line Sensors)	-	6,552	6,552	398 UG and 100 OH sensors installed; 300 pole sensors and 1000 OH sensors purchased for 2024 installation
8	CVR/VVO	-	1,766	1,766	
9	NWA: O'Shea Energy Storage	350	889	539	
10	NWA: Battery Trailer	750	1,191	441	
11	NWA: Omega Load Relief	700	2,454	1,754	
12	NWA: Fisher Load Relief	1,350	180	(1,170)	
13	NWA: Port Austin Load Relief	4,282	3,627	(655)	
14	NWA: Small Solar and Storage Testbed	500	400	(100)	
15	Sensor, Network and Algorithm Development (Solar Deployment)	1,178	1,058	(120)	
16	Technology Programs & NWA	-	1	1	
17	AMI: Meter Communications Upgrades	-	-	-	
18	Customer Power Status Visibility	-	-	-	
19	SCADA Remote Access and Configuration Platform	500	607	107	
20	Substation Reporting and Process Enhancements	-	-	-	
21	Asset Management Upgrades	1,725	2,121	396	
22	Systematic Tracking of Rotatable Assets	-	-	-	
23	External Crew Efficiency	-	-	-	
24	Tree Trim Risk Prioritization Model	1,440	3,824	2,384	
25	NWA: Veridian	3,308	1,832	(1,476)	
26	NWA: Adaptive Networked Microgrids	-	17	17	
27	NWA: Adaptive Networked Microgrids - Project Contributions	-	-	-	
28	NWA: EV Charging Demonstration at ACM	1,300	1,292	(8)	
29	Interconnection Process Enablement	3,991	3,693	(298)	
30	Grid Edge Insights & New Technology	1,960	1,819	(141)	
31	DER Control	290	-	(290)	
32	ADMS Enhancements	-	-	-	
33	Operational Technology and Error Free Communication	-	136	136	
34	Meter Improvements	-	-	-	
35	FLISR Implementation	-	-	-	
36	DERMS	4,640	-	(4,640)	Postponed investment while awaiting finalized MISO FERC 2222 requirements
37	Substation Cybersecurity	1,700	1,339	(361)	
38	Automation Configuration and Test Record Database	2,250	-	(2,250)	Project start delayed
39	Microwave End of Life	500	-	(500)	
40	Other Modernize Grid Management	375	26,411	26,036	See Witness Hartwick's testimony
41	ADMS: Network Management System	2,900	1,998	(902)	
42	Load Forecasting & Analytics	5,506	2,841	(2,665)	Project start delayed
43	Hosting Capacity Enablement	250	253	3	
44	Power Quality Analysis Program	-	-	-	
45	Substation Design Tool Upgrades	2,653	597	(2,056)	Project start delayed
46	Distribution Planning	-	8,447	8,447	Investments to bring operational data into the ADMS system
47	Enhance Maximo Capabilities and Processes	-	-	-	
48	Primary Service Orders Replatform	-	-	-	

Michigan Public Service Commission
DTE Electric Company
U-21297 vs.U-21534 2023 Forecast Comparison
Distribution Plant - Technology and Automation
(\$000)

Case No.: U-21534
Exhibit: A-23
Schedule: M2
Witness: A. J. Kryscynski
Page: 9 of 9

(a)		(b)	(c)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2023	U-21534 Forecast 12 mos. ending 12/31/2023	Over / (Under) Forecast	Explanation 1/
49	Work Management & Scheduling Upgrades	7,350	6,516	(834)	
50	Mobile tools expansion	-	-	-	
51	Maintain compliance	-	-	-	
52	Enhance and expand cybersecurity	-	-	-	
53	Mobile Equipment Replacement	-	-	-	
54	Mobile Technology	4,575	5,095	520	
55	SCADA / AMI Enhancements	-	-	-	
56	Total Technology and Automation Projects and Programs	136,604	165,605	29,001	

1/ Variance greater than two million dollars are explained
2/ Distribution Automation is collectively "Automation: Substation", "Automation: 13.2kV Circuit Distributions", and "4.8 kV Circuit Automation" in U-21297 (See Exh A-12, Sch B5.4, pg. 12 Line 9, 10, and 39, respectively)

Michigan Public Service Commission
DTE Electric Company
U-21297 vs. U-21534 2024 Forecast Comparison
Distribution Plant
(\$000)

Case No.: U-21534
Exhibit: A-23
Schedule: M3
Witness: A. J. Kryscynski
Page: 1 of 8

	(a)	(b)	(c)	(d)	(e)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2024	U-21534 Forecast 12 mos. ending 12/31/2024	Over / (Under) Forecast	Over / (Under) Percentage
1	Base Capital Programs				
2	Emergent Replacements				
3	Storm	226,973	244,066	17,093	8%
4	Non - Storm	188,384	220,275	31,892	17%
5	Substation Reactive	47,302	49,057	1,754	4%
6	Emergent Replacement Reduction Based on Strategic Spend	(39,239)	(20,820)	18,419	-47%
7	Subtotal Emergent Replacements	423,420	492,578	69,158	16%
8	Customer Connections, Relocations & Other				
9	Connections and New Load	203,345	206,069	2,724	1%
10	Relocations	26,521	52,202	25,681	97%
11	Electric System Equipment	30,138	33,300	3,162	10%
12	NRUC and Improvement Blankets	23,051	29,611	6,561	28%
13	General Plant, Tools & Equipment and Miscellaneous	6,262	9,144	2,882	46%
14	Public Lighting Department Project	-	-	-	
15	Subtotal Customer Connections, Relocations & Other	289,317	330,327	41,010	14%
13	Customer Advances for Construction	(27,940)	(27,111)	829	-3%
14	Total Base Capital Programs	684,797	795,794	110,998	16%
15					
16	Strategic Capital Programs				
17	Infrastructure Resilience and Hardening	238,796	295,363	56,566	24%
18	Infrastructure Redesign and Modernization	543,244	291,496	(251,749)	-46%
19	Technology and Automation	97,538	121,919	24,381	25%
20	Subtotal Strategic Capital Programs	879,579	708,777	(170,802)	-19%
21					
22	Total Capital	1,564,376	1,504,572	(59,804)	-4%

Michigan Public Service Commission
DTE Electric Company
U-21297 vs. U-21534 2024 Forecast Comparison
Distribution Plant - Connections, Relocations and Other
(\$000)

Case No.: U-21534
Exhibit: A-23
Schedule: M3
Witness: A. J. Kryscynski
Page: 2 of 8

	(a)	(b)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2024	U-21534 Forecast 12 mos. ending 12/31/2024	Over / (Under) Forecast
1	<u>Connections and New Load</u>			
2	Projected Small Load Growth Projects (Blanket)	23,831	21,962	(1,869)
3				
4	Projected Customer Connections	119,708	121,101	1,393
5	Projected Customer Connections CIAC	(17,079)	(18,091)	(1,011)
6	Projected Customer Connections (Net of CIAC)	102,629	103,011	382
7				
8	Projected New Business Projects	59,806	58,305	(1,501)
9	Projected New Business Projects CIAC	(10,330)	(7,298)	3,032
10	Projected New Business Projects (net of CIAC)	49,475	51,007	1,532
11				
12	Incremental Infrastructure for EV	-	4,700	4,700
13				
14	Total Connections and New Load	203,345	206,069	2,724
15	Total Connections and New Load CIAC	(27,410)	(25,388)	2,021
16	Total Connections and New Load (Net of CIAC)	175,935	180,680	4,745
17				
18	<u>Relocations</u>			
19	Projected Small Relocation Projects (Blanket)	7,721	11,651	3,930
20				
21	Major Infrastructure Relocation Project			
22	Gordie Howe International Bridge	-	-	-
23	I-375 Relocations	-	25,000	25,000
24				
25	Relocation Projects (excl. Major Infrastructure Projects)	18,800	15,551	(3,249)
26	Relocation Projects CIAC	(531)	(1,723)	(1,192)
27	Subtotal Relocation Projects (Net of CIAC)	18,269	13,828	(4,441)
28				
29	Total Relocations	26,521	52,202	25,681
30	Total Relocations CIAC	(531)	(1,723)	(1,192)
31	Total Relocations (Net of CIAC)	25,990	50,480	24,490
32				
33	<u>Electric System Equipment</u>			
34	Distribution Transformers & Regulators	-	-	-
35	Projected Major Equipment	14,956	15,742	786
36	Projected Meters	15,183	17,559	2,376
37	Total Electric System Equipment	30,138	33,300	3,162
38				
39	<u>NRUC and Improvement Blankets</u>			
40	Projected System Improvements	10,688	16,454	5,766
41	Projected Normal Retirement Unit Changeouts (NRUC)	6,273	6,904	631
42	Projected Operational Technologies	6,089	6,253	164
43	Total NRUC and Improvement Blankets	23,051	29,611	6,561
44				
45	<u>General Plant, Tools & Equipment and Miscellaneous</u>			
46	Projected Substation Physical Security	-	1,127	1,127
47	Projected General Plant, Tools & Equipment and Miscellaneous	6,262	8,017	1,755
48	Total General Plant, Tools & Equipment and Miscellaneous	6,262	9,144	2,882
49				
50	<u>Public Lighting Department Project</u>			
51		-	-	-
52	Total Customer Connections, Relocations & Other	289,317	330,327	41,010
53	Total Cust Connections, Relocations & Other CIAC	(27,940)	(27,111)	829
54	Total Cust Connections, Relocations & Other Net of CIAC	261,376	303,216	41,840

Michigan Public Service Commission
DTE Electric Company
U-21297 vs. U-21534 2024 Forecast Comparison
Distribution Plant - Infrastructure Resilience and Hardening
(\$000)

Case No.: U-21534
Exhibit: A-23
Schedule: M3
Witness: A. J. Kryscynski
Page: 3 of 8

(a)		(b)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2024	U-21534 Forecast 12 mos. ending 12/31/2024	Over / (Under) Forecast
1	Infrastructure Resilience and Hardening			
2	Mobile Fleet Program	4,500	5,000	500
3	Substation Risk: Drexel	-	-	-
4	Substation Risk: Chestnut	7,245	2,725	(4,520)
5	Substation Risk: Savage	-	-	-
6	Substation Risk: Apache	2,638	3,810	1,173
7	Substation Risk: Port Huron	-	-	-
8	Substation Risk: Belleville Switchgear Decommission	-	-	-
9	Substation Risk: McGraw	9	37,852	37,843
10	Substation Risk: Voyager	-	-	-
11	Substation Risk: Flood Defense Program	-	5,009	5,009
12	4.8 kV Hardening	-	80,000	80,000
13	Pole and Pole Top Maintenance and Modernization (PTMM)	120,587	63,450	(57,137)
14	Cable Replacement Program	25,000	15,001	(9,999)
15	Frequent Outage Program (CEMI)	47,625	48,050	425
16	Breaker Replacement Program	-	-	-
17	Pontiac Vaults	-	-	-
18	URD Replacement Program	-	-	-
19	URD Replacement Program: Detroit URD 1-1	-	-	-
20	40 kV: Automatic Pole Top Switch	6,338	4,995	(1,343)
21	Disconnect and Switcher Replacement	4,900	4,900	-
22	Steel Pole Highway Crossings	5,000	5,000	-
23	Station Upgrade: Warren (Relay Replacement)	-	-	-
24	Station Upgrade: Northeast (Relay Replacement)	-	-	-
25	Batteries and Chargers Replacement Program	2,500	2,500	-
26	Substation Risk: Hood	-	6,918	6,918
27	Substation Risk: UNVIL 301 B1 Conversion	-	-	-
28	Portable Generators	-	4,500	4,500
29	Station Upgrade: Lincoln	5,300	-	(5,300)
30	SCADA Pole Top Device Replacement	1,808	1,808	-
31	Substation Regulator Replacement	904	816	(88)
32	Station Upgrade: Navarre	330	330	-
33	Station Upgrade: 120kV Relays Upgrade for ITC Projects	4,112	2,698	(1,414)
34	Substation Risk: Savage Switchgear Replacement	-	-	-
35	Substation Risk: Seville	-	-	-
36	Substation Risk: Imlay	-	-	-
37	Total Infrastructure Resilience and Hardening Projects and Programs	238,796	295,363	56,566

Michigan Public Service Commission
DTE Electric Company
U-21297 vs. U-21534 2024 Forecast Comparison
Distribution Plant - Infrastructure Redesign and Modernization
(\$000)

Case No.: U-21534
Exhibit: A-23
Schedule: M3
Witness: A. J. Kryscynski
Page: 4 of 8

(a)		(b)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2024	U-21534 Forecast 12 mos. ending 12/31/2024	Over / (Under) Forecast
1	Infrastructure Redesign and Modernization			
2	Ann Arbor System Improvements: State Substation	-	-	-
3	Ann Arbor System Improvements: Apex (Blue) Substation	-	-	-
4	Ann Arbor System Improvements: Argo 40kV Reconfiguration	7,400	3,000	(4,400)
5	Subtransmission Redesign & Rebuild: Transformer High Side Protection Program	5,500	4,745	(755)
6	Subtransmission Redesign & Rebuild: Maxwell Amherst	-	-	-
7	Subtransmission Redesign & Rebuild: Trunk 7106	-	-	-
8	Subtransmission Redesign & Rebuild: Trunk 2255	-	-	-
9	Subtransmission Redesign & Rebuild: Trunk 2237-ST	-	-	-
10	Subtransmission Redesign & Rebuild: Trunk 7333	-	-	-
11	Subtransmission Redesign & Rebuild: Sandusky Transformer 101 Breaker	-	4,070	4,070
12	Subtransmission Redesign & Rebuild: Boyne	-	3,026	3,026
13	Subtransmission Redesign & Rebuild: Tie 4105 Phase 1 1/	-	-	-
14	Subtransmission Redesign & Rebuild: Tie 4105 Phase 3 1/	1,817	2,259	442
15	Subtransmission Redesign & Rebuild: Tie 4105 Phase 4 1/	8,490	-	(8,490)
16	Subtransmission Redesign & Rebuild: Tie 1568	-	-	-
17	Subtransmission Redesign & Rebuild: Trunk 4217	-	2,265	2,265
18	Subtransmission Redesign & Rebuild: Trunk 3509	1,217	3,653	2,437
19	Subtransmission Redesign & Rebuild: Trunk 4266	5,096	-	(5,096)
20	Subtransmission Redesign & Rebuild: Praxair	-	565	565
21	Subtransmission Redesign & Rebuild: Small Projects & Reserve	415	500	85
22	Subtransmission Breaker Short Circuit Violations	95	50	(45)
23	Subtransmission Redesign & Rebuild: Slocum	-	-	-
24	Subtransmission Redesign & Rebuild: 40kV Capacitor Banks at Armada and Adair	-	260	260
25	Subtransmission Redesign & Rebuild: Oak Beach Capacitor	-	-	-
26	Subtransmission Redesign & Rebuild: Tie 6907	1,790	-	(1,790)
27	Subtransmission Redesign & Rebuild: Tie 6602	3,689	-	(3,689)
28	Subtransmission Redesign & Rebuild: Trunk 2419	785	-	(785)
29	Subtransmission Redesign & Rebuild: Kennett	315	-	(315)
30	Subtransmission Redesign & Rebuild: Trunk 4601	1,711	-	(1,711)
31	Subtransmission Redesign & Rebuild: Tempest Phase II	8,353	-	(8,353)
32	Subtransmission Redesign & Rebuild: Waterman	2,207	-	(2,207)
33	Subtransmission Redesign & Rebuild: Trunk 7105	270	-	(270)
34	Subtransmission Redesign & Rebuild: Tie 5208	500	-	(500)
35	TCHPP Switchyard Upgrades	-	3,309	3,309
36	Trunk and Tie Lines Hardening Program: Prior Year's	-	-	-
37	CODI: Charlotte Network Upgrade	11,673	10,967	(707)
38	CODI: Targeted Network Secondary Cable Replacement	3,800	3,800	-
39	CODI: Corktown Substation	-	-	-
40	CODI: Islandview Substation - Phase 1 2/	26	7	(20)
41	CODI: Islandview Substation - Phase 2 2/	30,932	8,000	(22,932)
42	CODI: Islandview Substation - Phase 3 2/	11,599	-	(11,599)
43	CODI: Islandview Substation - Phase 4 2/	3,866	-	(3,866)
44	CODI: Midtown Substation Expansion	-	459	459
45	CODI: Alfred Substation Expansion	11,782	18,235	6,452
46	CODI: Howard Conversion	15,000	-	(15,000)
47	4.8 kV CC: Cortland / Oakman / Linwood Consolidation	-	2,537	2,537
48	4.8 kV CC: Ariel Substation and Circuit Conversion	-	-	-
49	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - Below Grade 3/	-	-	-
50	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - Above Grade 3/	4,063	1,311	(2,752)
51	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - System Conduit 3/	11,630	-	(11,630)
52	4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade) - Phase 4 3/	17,446	-	(17,446)
53	4.8 kV CC: Almont Relief and Circuit Conversion (Midas)	-	6,000	6,000

Michigan Public Service Commission
DTE Electric Company
U-21297 vs. U-21534 2024 Forecast Comparison
Distribution Plant - Infrastructure Redesign and Modernization
(\$000)

Case No.: U-21534
Exhibit: A-23
Schedule: M3
Witness: A. J. Kryscynski
Page: 5 of 8

(a)		(b)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2024	U-21534 Forecast 12 mos. ending 12/31/2024	Over / (Under) Forecast
54	4.8 kV CC: Buckler Circuit Conversion	2,648	3,922	1,274
55	4.8 kV CC: McKinstry Sub Decommission	-	3,376	3,376
56	4.8 kV CC: Quincy Conversion	-	1,692	1,692
57	4.8 kV CC: Pinegrove Substation Relocation and Conversion	24,780	51,226	26,446
58	4.8 kV CC: Pinegrove Substation Relocation and Conversion CIAC	(8,700)	(17,000)	(8,300)
59	4.8 kV CC: Hawthorne Relief and Circuit Conversion	13,000	3,373	(9,627)
60	4.8 kV CC: Crestwood Substation	-	-	-
61	4.8 kV CC: MAUME 8241 Downtown Clawson Conversion	-	-	-
62	4.8 kV CC: Power line Conversion of MADSN 175L-W	-	-	-
63	4.8 kV CC: GRFIN & WMSTN Conversions	8,019	6,300	(1,719)
64	4.8kV CC: SCOTN	1,087	1,885	798
65	4.8 kV CC: Slater	-	-	-
66	4.8 kV CC: Royal Oak Substation and Circuit Conversion	15,100	-	(15,100)
67	4.8 kV CC: Curtis	-	2,174	2,174
68	4.8 kV CC: Unionville DC 301 B1 Conversion	-	2,911	2,911
69	4.8 kV CC: Hilton Substation and Circuit Conversion	-	-	-
70	4.8 kV CC: Hawthorne Trf #2 and Secondary Cable Replacement	-	-	-
71	4.8kV CC: Rochester Decommissioning and Tienken Relief	711	-	(711)
72	4.8 kV CC: Ann Arbor AC Network Conversion	711	-	(711)
73	4.8kV CC: Pittsfield Substation and Circuit Conversion	2,423	-	(2,423)
74	4.8kV CC: Yale-Slater Decommissioning and Circuit Conversion	4,319	-	(4,319)
75	4.8 kV CC: Grosse Pointe Substation and Circuit Conversion	15,100	-	(15,100)
76	System Loading: Brest Substation	-	-	-
77	System Loading: Carleton	-	-	-
78	System Loading: Grayling	-	-	-
79	System Loading: Prospect	-	-	-
80	System Loading: Mandy 307 Load Transfer	-	-	-
81	System Loading: Mack Transformer 102	-	-	-
82	System Loading: Globe	2,358	200	(2,158)
83	Pilot: Strategic and Service Undergrounding	1,900	15,644	13,744
84	Pilot: Primary Deconductoring	-	-	-
85	Subtransmission Redesign & Rebuild: Tie 810	20,890	13,000	(7,890)
86	Subtransmission Redesign & Rebuild: Tie 7504	6,430	500	(5,930)
87	Subtransmission Redesign & Rebuild: Tie 4105 Phase 2	1/ 161	-	(161)
88	Subtransmission Redesign & Rebuild: Tie 4105 Phase 5	1/ 161	-	(161)
89	Subtransmission Redesign & Rebuild: Trunk 2308	2,030	970	(1,060)
90	Subtransmission Redesign & Rebuild: Tie 3205	4,793	-	(4,793)
91	Subtransmission Redesign & Rebuild: Reverse Power Relay Scheme Program	-	150	150
92	Subtransmission Redesign & Rebuild: Tie 4104	11,697	-	(11,697)
93	Subtransmission Redesign & Rebuild: Badax Transformer 102 Addition	1,503	580	(923)
94	Subtransmission Redesign & Rebuild: Trunk 4245	1,000	600	(400)
95	Subtransmission Redesign & Rebuild: Trunk 4911	8,209	-	(8,209)
96	Subtransmission Redesign & Rebuild: Custer Republic	1,658	-	(1,658)
97	Subtransmission Redesign & Rebuild: Cortland Station Expansion	2,379	101	(2,278)
98	CODI: CATO Substation Expansion	13,300	14,172	872
99	CODI: Garfield Radial (Midtown Circuits)	4/ 17,151	11,633	(5,518)
100	CODI: Garfield Network Upgrade	4/ 19,068	17,300	(1,768)
101	CODI: Kent/Gibson Conversion - Phase 1	5/ 39,751	15,107	(24,644)
102	4.8 kV CC: Zenon Substation and Circuit Conversion	-	-	-
103	4.8 kV CC: Calla Circuit Conversion and Phase 2	3,926	-	(3,926)
104	4.8 kV CC: Lapeer - Elba Expansion and Circuit Conversion (Apollo)	16,982	3,558	(13,424)
105	4.8 kV CC: Birmingham Decommissioning and Circuit Conversion	4,540	1,333	(3,207)
106	4.8 kV CC: ISO Conversion Program	40,000	1,700	(38,300)

Michigan Public Service Commission
DTE Electric Company
U-21297 vs. U-21534 2024 Forecast Comparison
Distribution Plant - Infrastructure Redesign and Modernization
(\$000)

Case No.: U-21534
Exhibit: A-23
Schedule: M3
Witness: A. J. Kryscynski
Page: 6 of 8

(a)		(b)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2024	U-21534 Forecast 12 mos. ending 12/31/2024	Over / (Under) Forecast
107	4.8 kV CC: Hemlock Decommissioning and Circuit Conversion	1,371	750	(621)
108	4.8 kV CC: White Lake Decommissioning and Circuit Conversion	-	-	-
109	8.3 kV CC: Pontiac Overhead Conversion	23,582	19,177	(4,405)
110	8.3 kV CC: Pontiac Underground Conversion	3,428	3,250	(178)
111	System Loading: Brown City	8,392	7,392	(1,000)
112	System Loading: Port Sanilac	6,034	2,389	(3,645)
113	System Loading: Richmond/Armada	7,050	8,893	1,843
114	System Loading: Cody	1,584	1,600	16
115	System Loading: Otsego/Capac/Shaw	1,688	88	(1,600)
116	System Loading: Macomb/Golf	126	-	(126)
117	System Loading: Grenada	7,535	6,535	(1,000)
118	System Loading: Lark/Spruce	607	1,350	744
119	System Loading: Jewell	500	592	92
120	System Loading: Mayville	150	-	(150)
121	System Loading: Goodison	79	-	(79)
122	System Loading: Wixom	3,033	2,033	(1,000)
123	System Loading: Diamond	21	21	-
124	System Loading: Spokane/Seneca	5,984	-	(5,984)
125	System Loading: Sterling	756	336	(420)
126	System Loading: Disco	417	417	-
127	System Loading: Tahoe	354	-	(354)
128	System Loading: New Baltimore/Chesterfield	-	250	250
129	System Loading: Kings Point	-	1,000	1,000
130	Total Infrastructure Redesign and Modernization Projects and Programs	543,244	291,496	(251,749)

1/ Tie 4105 phases on lines 13-15 and 84-85 were collectively "Subtransmission Redesign & Rebuild: Tie 4105" in U-21297 (Exh A-12, Sch B5.4, pg. 9, Line 17). Tie 4105 was forecasted at \$10,629 in U-21297 compared to \$2,259 in U-21534.

2/ CODI: Islandview Substation phases on lines 40-43 were collectively "CODI: Islandview Substation" in U-21297 (Exh A-12, Sch B5.4, pg. 10, Line 45). Islandview was forecasted at \$46,424 in U-21297 compared to \$8,007 in U-21534.

3/ Promenade phases on lines 49-50 and 127-128 were collectively "4.8 kV CC: I-94 Substation and Circuit Conversion (Promenade)" in U-21297 (Exh A-12, Sch B5.4, pg. 10, Line 56). Promenade was forecasted at \$33,139 in U-21297 compared to \$1,311 in U-21534.

4/ CODI: Garfield projects on lines 99-100 were collectively "CODI: Garfield Network Upgrade" in U-21297 (Exh A-12, Sch B5.4, pg. 10, Line 50). CODI: Garfield was forecasted \$36,220 in U-21297 compared to \$28,933 in U-21534.

5/ CODI: Kent/Gibson Conversion - Phase 1 on line 82 was "CODI: Kent/Gibson Conversion" in U-21297 (Exh A-12, Sch B5.4, pg. 10, Line 51).

Michigan Public Service Commission
DTE Electric Company
U-21297 vs. U-21534 2024 Forecast Comparison
Distribution Plant - Technology and Automation
(\$000)

Case No.: U-21534
Exhibit: A-23
Schedule: M3
Witness: A. J. Kryscynski
Page: 7 of 8

(a)		(b)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2024	U-21534 Forecast 12 mos. ending 12/31/2024	Over / (Under) Forecast
1	<u>Technology and Automation</u>			
2	Distribution Automation	1/ 29,000	21,188	(7,812)
3	ADMS: DMS/OMS	-	-	-
4	SOC: ESOC	-	-	-
5	SOC: ASOC	1,000	-	(1,000)
6	Grid Automation Telecommunications	16,861	16,900	39
7	Distribution Sensing and Monitoring (inclgd Line Sensors)	-	500	500
8	CVR/VVO	5,000	2,500	(2,500)
9	NWA: O'Shea Energy Storage	-	54	54
10	NWA: Battery Trailer	2,250	2,250	-
11	NWA: Omega Load Relief	-	27	27
12	NWA: Fisher Load Relief	4,650	4,524	(126)
13	NWA: Port Austin Load Relief	775	1,486	710
14	NWA: Small Solar and Storage Testbed	500	565	65
15	Sensor, Network and Algorithm Development (Solar Deployment)	204	200	(4)
16	Technology Programs & NWA	-	-	-
17	AMI: Meter Communications Upgrades	-	-	-
18	Customer Power Status Visibility	-	15,942	15,942
19	SCADA Remote Access and Configuration Platform	-	-	-
20	Substation Reporting and Process Enhancements	-	200	200
21	Asset Management Upgrades	1,500	-	(1,500)
22	Systematic Tracking of Rotatable Assets	-	-	-
23	External Crew Efficiency	-	4,407	4,407
24	Tree Trim Risk Prioritization Model	-	-	-
25	NWA: Veridian	4,625	2,646	(1,979)
26	NWA: Adaptive Networked Microgrids	-	4,588	4,588
27	NWA: Adaptive Networked Microgrids - Project Contributions	-	(2,609)	(2,609)
28	NWA: EV Charging Demonstration at ACM	2,628	920	(1,709)
29	Interconnection Process Enablement	5,607	1,900	(3,707)
30	Grid Edge Insights & New Technology	2,191	5,935	3,744
31	DER Control	290	290	-
32	ADMS Enhancements	-	7,000	7,000
33	Operational Technology and Error Free Communication	-	5,600	5,600
34	Meter Improvements	-	1,400	1,400
35	FLISR Implementation	-	4,412	4,412
36	DERMS	2,540	-	(2,540)
37	Substation Cybersecurity	-	400	400
38	Automation Configuration and Test Record Database	2,250	1,400	(850)
39	Microwave End of Life	500	250	(250)
40	Other Modernize Grid Management	2,225	2,200	(25)
41	ADMS: Network Management System	2,900	1,600	(1,300)
42	Load Forecasting & Analytics	4,275	3,900	(375)
43	Hosting Capacity Enablement	150	350	200
44	Power Quality Analysis Program	-	400	400
45	Substation Design Tool Upgrades	1,866	1,250	(616)
46	Distribution Planning	-	1,572	1,572
47	Enhance Maximo Capabilities and Processes	-	-	-
48	Primary Service Orders Replatform	-	2,000	2,000
49	Work Management & Scheduling Upgrades	3,025	790	(2,235)
50	Mobile tools expansion	-	1,100	1,100
51	Maintain compliance	-	200	200
52	Enhance and expand cybersecurity	-	300	300
53	Mobile Equipment Replacement	-	881	881

Michigan Public Service Commission
DTE Electric Company
U-21297 vs. U-21534 2024 Forecast Comparison
Distribution Plant - Technology and Automation
(\$000)

Case No.: U-21534
Exhibit: A-23
Schedule: M3
Witness: A. J. Kryscynski
Page: 8 of 8

	(a)	(b)	(c)	(d)
Line No.	Description	U-21297 Forecast 12 mos. ending 12/31/2024	U-21534 Forecast 12 mos. ending 12/31/2024	Over / (Under) Forecast
54	Mobile Technology	725	500	(225)
55	SCADA / AMI Enhancements	-	-	-
56	Total Technology and Automation Projects and Programs	97,538	121,919	24,381

1/ Distribution Automation is collectively "Automation: Substation", "Automation: 13.2kV Circuit Distributions", and "4.8 kV Circuit Automation" in U-21297 (See Exh A-12, Sch B5.4, pg. 12 Line 9, 10, and 39, respectively)

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

PANKAJ SHARMA

DTE ELECTRIC COMPANY
QUALIFICATIONS AND REVISED DIRECT TESTIMONY OF PANKAJ
SHARMA

Line
No.

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

2 A1. My name is Pankaj Sharma (he/him/his). My business address is One Energy Plaza
3 Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC
4 (LLC), as Director – Information Officer within the Information Technology
5 Services (ITS) organization.

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

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

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

11 A3. I have a master's degree in Computer Application from University of Rajasthan,
12 India. I have a Bachelor of Science in Mathematics from Agra University, India.

13
14 **Q4. What work experience do you have?**

15 A4. I have worked for DTE Energy or one of its regulated utilities for over 22 years in
16 various Information Technology (IT) positions. I am currently the IT Director of
17 Infrastructure Operations for DTE Energy, LLC as well as supporting the DTE
18 Electric and the DTE Gas Companies. Prior to my current position, I was the
19 Director – Information Protection & Security within the Information Technology
20 Services (ITS) organization.

21
22 **Q5. Do you hold any certifications or are you a member of any professional**
23 **organizations?**

Line
No.

1 A5. I am a member of Project Management Institute (PMI) Org¹ since 2002 and have
2 maintained a Project Management Professional (PMP) Certification² since 2005. I
3 have been an active member of the Information Systems Audit and Control
4 Association® (ISACA³) since 2019 and maintain ISACA's Certified Information
5 Security Manager (CISM)⁴ certification. In my professional career I have been
6 certified in ITIL Foundation, a leading industry standard and global framework for
7 IT service management and delivery. The ITIL framework offers a detailed set of
8 practices for managing and delivering IT services.

9

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

11 A6. As the IT Director of Infrastructure Operations, I am responsible for all aspects of
12 ITS Operational matters as well as being the infrastructure owner for all DTE
13 Shared ITS assets and asset classes. My department designs, integrates, and
14 operates all the common ITS assets including, but not limited to, the DTE Corporate
15 Network, DTE Energy Data Centers, Server and Storage assets and Endpoint
16 Devices. My department also supports other Company IT related assets such as
17 Operational Technologies (OT) used by various business units to operate the gas
18 and electric distribution networks located in dispersed facilities and locations.
19 Examples of this would include technology at power plants, substations, service
20 center locations, dedicated field sites and data centers.

21

¹ Project Management Institute (PMI) is the leading professional association for project management, and the authority for a growing global community of millions of project professionals (Ref : <https://www.pmi.org/about>) accessed 11/17/22

² The Project Management Professional (PMP)® is the world's leading project management certification. (Ref: <https://www.pmi.org/certifications/project-management-pmp>). accessed 11/17/22

³ <https://www.isaca.org/why-isaca/about-us/history> accessed 11/17/22

⁴ <https://www.isaca.org/credentialing/cism>. accessed 11/17/22

Line
No.

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

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

4 U-20836 2022 Electric Rate Case

5 U-21297 2023 Electric Rate Case

Line
No.

1 **Part I. Purpose of Testimony**

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

3 A8. The purpose of my direct testimony is to:

4 Describe the IT Capital investment framework and planning process that drives
5 prioritization of both single and multi-year projects and programs.

6 • Discuss overall IT O&M spend as well as O&M spend supporting the capital
7 investments.

8 • Specifically support the reasonableness of DTE Electric's IT capital
9 expenditures in the amount of \$224.3 million for the historical test year ended
10 December 31, 2022, \$314.6 million in the bridge period (for the 24 months
11 ending December 31, 2024), and \$145.7 million for the projected test period
12 ending December 31, 2025; and

13 • Discuss the variance of actual 2022 capital spend compared to 2022 capital
14 spend approved in, MPSC Case No. U-21297. Additionally, provide
15 explanation for projected budget differences in 2023 and 2024 (as compared to
16 U-21297) for projects that meet the requirement established in U-20162 final
17 order.

18

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

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

21	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
22	A-12	B5.7	Projected Capital Expenditures - Information
23			Technology
24	A-12	B5.7.1	Corporate Applications
25	A-12	B5.7.2	Customer Service (Sharma)

Line
No.

1	A-12	B5.7.4	Plant & Field
2	A-12	B5.7.5	Information Technology for IT (IT for IT)
3	A-12	B5.7.6	Information Protection Security (IPS)
4	A-12	B5.7.7	Infrastructure Operations
5	A-12	B5.7.8	Enterprise Data & Analytics
6	A-12	B5.7.9	Innovations
7	A-24	N1	IT Business Cases – Executive Summaries
8	A-24	N2	Historical Spend Variance Summary
9	A-24	N3	IT Capital Investments with Additional Project
10			Details
11	A-13	C5.13	Projected Operation and Maintenance
12			Expenses - Information Technology

13

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

15 A10. Yes, they were. I co-sponsor Exhibits A-24, Schedules N1, N2, and N3 with
16 Company Witness Hatsios.

17

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

19 A11. My testimony consists of four parts:

20	Part I	Purpose of Testimony
21	Part II	Investment Framework
22	Part III	Portfolio Details
23	Part IV	Historical Spend Variance

24

Line
No.

1 **Q12. Can you describe the requirements provided by the Commission in previous**
2 **orders?**

3 A12. Yes, in Case U-18238, the MPSC set forth seven requirements directly related to
4 the highest cost Top 25 IT and OT projects in the projected test year. These
5 requirements can be found in Part III filing. The Part III requirements were further
6 revised in the updated order dated May 18, 2023, to include additional information
7 in a spreadsheet and readable PDF format. In Case U-20162, the MPSC requested
8 the Company to provide a breakdown of both O&M and Capital cost into two or
9 three sub-categories, nine additional requirements for projects greater than \$0.5
10 million addressing scope, schedule, cost, and alternatives.
11 Recently in the final order in U-21297, the Commission directed the Company to
12 provide an exhibit outlining IT O&M spend which is included as Exhibit U-21534
13 IT O&M Exhibit A-13 Schedule C5.13.

14

15 **Q13. What is the process used by the Company in identifying and prioritizing IT**
16 **Investment projects?**

17 A13. DTE's Annual Planning Cycle (APC) is how the Company refines its investment
18 strategies, establishes financial targets, and sanctions work. This approach also
19 applies to IT investments. The business units come together annually to review,
20 prioritize, and authorize the next two years of IT investments, aligned with the
21 assigned capital targets, as shown in Figure 1. This process is detailed in the DTE
22 Five-Year IT Plan 2021-2025 filed in Docket No. U-20561.

23

Line
No.

1

Figure 1 DTE IT APC Cadence



2 The business unit project sponsor, with support from their IT liaisons, submits a
3 business case into the IT APC process that documents the opportunity,
4 functionality, or capability sought, the value proposition, related key output
5 measures, key objectives, alternative analysis, and cost estimate. A Project
6 Prioritization Score (PPS) is then applied to the project based on the alignment of
7 the investment to the Company's strategies and goals.

8 The IT organization utilizes PPS to prioritize investments. Once the PPS is applied,
9 the business case enters the enterprise IT Investment prioritization model where it
10 is evaluated against execution capacity to ensure that there is a high degree of
11 confidence the projects will be executed as planned. The model then optimizes the
12 number of projects to be implemented by the Company. The Company's IT
13 investment plan is reviewed and approved by the Company's executive Technology
14 Investment Committee (TIC). The business case executive summaries are provided
15 in Exhibit A-24 Schedule N1.

16

17 **Q14. Can you further explain how the project benefits are evaluated using the**
18 **Project Prioritization Scoring model?**

19 A14. The Company completed benchmarking on industry best practices in investment
20 prioritization. As a result, the Company hired an industry consulting firm to apply

Line
No.

1 these best practices to establish a framework used to evaluate, score, and prioritize
2 projects. This framework is similar to what market leading IT research
3 recommends. For reference, Gartner research⁵ also helped enabling companies to
4 establish a model that will prioritize digital investments that maximize business
5 value. These business value outcomes include revenue and cost, but also focus on
6 risk reduction, efficiency, and value. Based on this informed research and best
7 practices, the Company's prioritization model considers both qualitative and
8 quantitative benefits across seven weighted benefit categories when considering IT
9 Enhancements and Strategic investments for prioritization of discretionary funding,
10 as shown in Figure 2. The result of this benefit analysis is a Project Prioritization
11 Score (PPS). This PPS score is used as a standardized scoring and ranking
12 methodology to bring consistency to how projects across multiple investment
13 portfolios are assessed. Non-discretionary Regulatory/Compliance, Sustainment,
14 and Return-to-Health projects are considered "must do" and therefore do not
15 require a benefit analysis. The non-discretionary projects are assigned a standard
16 score based on the associated investment category. The PPS score was introduced
17 into the APC prioritization starting with the 2023 investment planning, so all 2023
18 and beyond, business cases will include the PPS score. Scoring categories and
19 weighting are subject to change to ensure ongoing alignment with the priorities the
20 Company believes are in the best near-term and long-term interest of its customers.
21

⁵ Gartner Research Article - 'Prioritize Digital Investments That Maximize Business Value', Published 18 April 2022 - ID G00752285.

Line
No.

1

Figure 2 Project Prioritization Score Criteria

Scoring Category	Strategic Fit			Financial Impact		Operational Impact		Total
	Strategic Alignment	Customer Experience	Employee Engagement	Affordability & Growth	Benefit/Cost	Operational Reliability	Foundational Capability	Weight
Weighting Scale	10%	30%	10%	20%	10%	15%	5%	100%

2

Part II - Investment Framework

Q15. What are the Company's IT Capital Expenditures - Summary Exhibit A-12 Schedule B5.7?

A15. Exhibit A-12 Schedule B5.7 focuses on IT Capital projects which reside in the IT portfolios as defined in DTE Five-Year IT Plan 2021-2025 filed in Docket No. U-20561. These projects span across the historical year (2022), bridge year (24 months ending 12/31/2024) and the projected test year (12 months ending 12/31/2025) periods by category.

11

Q16. Can you describe the capital cost and the corresponding O&M costs for IT Projects?

A16. The capital costs reflected in Exhibits A-24 Schedule N-3 and A-12 Schedule B5.7 presented is only the portion of IT costs allowed to be capitalized in accordance with DTE's accounting policies such as hardware costs, software costs, and software development costs. These policies define the scope and phases of a project that can be capitalized and the scope and phases of the project that should be expensed. According to these policies the O&M cost is considered Cost To Achieve (CTA). The O&M costs reflected in Exhibit A-24 Schedule N-3 represent

20

Line
No.

1 the total O&M cost to achieve each project and are provided for informational
2 purposes only.

3

4 **Q17. Can you provide a more detailed description of other IT O&M cost?**

5 A17. Yes, in addition to CTA expense, in order for the ITS organization to operate within
6 the Company the ITS operating expense includes operational labor support (Base
7 Operate) and software maintenance cost (License Management & Maintenance).
8 The IT Operational support cost represents IT resources that support hardware and
9 software defect remediation (e.g. Office 365 not working as expected, Password
10 Reset Support, MFA failure and access requests), business support services (e.g.,
11 IT Help Desk, Data Center Operation), and IT administration. Commercial
12 software maintenance and support represents IT O&M expense include software
13 maintenance and license for use fees for on premise and cloud solutions for certain
14 specific contracts.

15 To support the Commission requirement to provide more detail supporting IT
16 O&M, I have provided the following exhibit: U-21534 IT O&M Exhibit A-13
17 Schedule C5.13. The 'A&G Capitalized' on line 7, reflects the transfer (allocation)
18 of A&G costs to capital as an overhead. The amount of A&G transferred
19 (allocated) is based on the percentage of total direct labor charged to capital.

20

21 **Q18. Can you describe how IT projects are estimated?**

22 A18. Yes, IT projects approved through the ITS Annual Planning Cycle are processed
23 through a thorough, detailed estimation process. This is enabled through
24 ServiceNow demand management module utilized for planning IT investments.
25 The Demand manager estimates project labor by phase of the project, and for any

Line
No.

oversight/governance or project management cost. The demand management team is also responsible for obtaining and providing any associated vendor or solution estimates. In addition to these project level cost estimates, each demand has 28 discrete tasks generated to seven different workstreams (Architecture, Endpoints, IDSS, IPS, IOC, Enterprise Monitoring, & Network) to provide requirement and deliverable based estimation and analysis, as seen in Figure 3 below. There are a total of 169 discrete project elements available to estimate on any given project as applicable, which are required to support project execution.

Figure 3 IT APC Estimation Table Example

Details	Business Case	Financials	Assessment Data	Notes	Preferences	Architecture Estimate	Endpoints Estimate	IDSS Estimate	IPS Estimate	IOC Estimate	Enterprise Monitoring Estimate	Network Estimate
Other Cost Estimates		Detailed Assessments										
IDSS Estimate												
⊞ ⏪ ⏩ 1 to 28 of 28												
Category Type ▲		DTE Hours	Contract Hours	Total Cost	Capital %	O&M %	Comments					
⊞	Database - BCV refresh setup	0	0	\$0.00	100%		0%					
	Database - Database Only Failover	0	0	\$0.00	100%		0%					
	Database - Database Tuning	0	0	\$0.00	100%		0%					
	Database - DB Environment Design	0	0	\$0.00	100%		0%					
	Database - Deploy Schema	0	0	\$0.00	100%		0%					
	Database - Performance Monitoring	0	0	\$0.00	100%		0%					
	Database - Schema Changes	0	0	\$0.00	100%		0%					
	Database - Security	0	0	\$0.00	100%		0%					
	Database - SQL Tuning per statement	0	0	\$0.00	100%		0%					
	Database - Tablespace Design	0	0	\$0.00	100%		0%					
	Database - Transmit export to vendor	0	0	\$0.00	100%		0%					
	IDSS - Other (Provide comment)	0	0	\$0.00	100%		0%					
	IDSS - Cloud Support	0	0	\$0.00	100%		0%					
	Middle Tier - Configure Portal Portlet	0	0	\$0.00	100%		0%					
	Middle Tier - Deploy Portal Portlet	0	0	\$0.00	100%		0%					
	Middle Tier - IIS Configuration	0	0	\$0.00	100%		0%					
	Middle Tier - J2E Deployment	0	0	\$0.00	100%		0%					
	Middle Tier - Load Balancer Config	0	0	\$0.00	100%		0%					
	Middle Tier - MQ Setup	0	0	\$0.00	100%		0%					

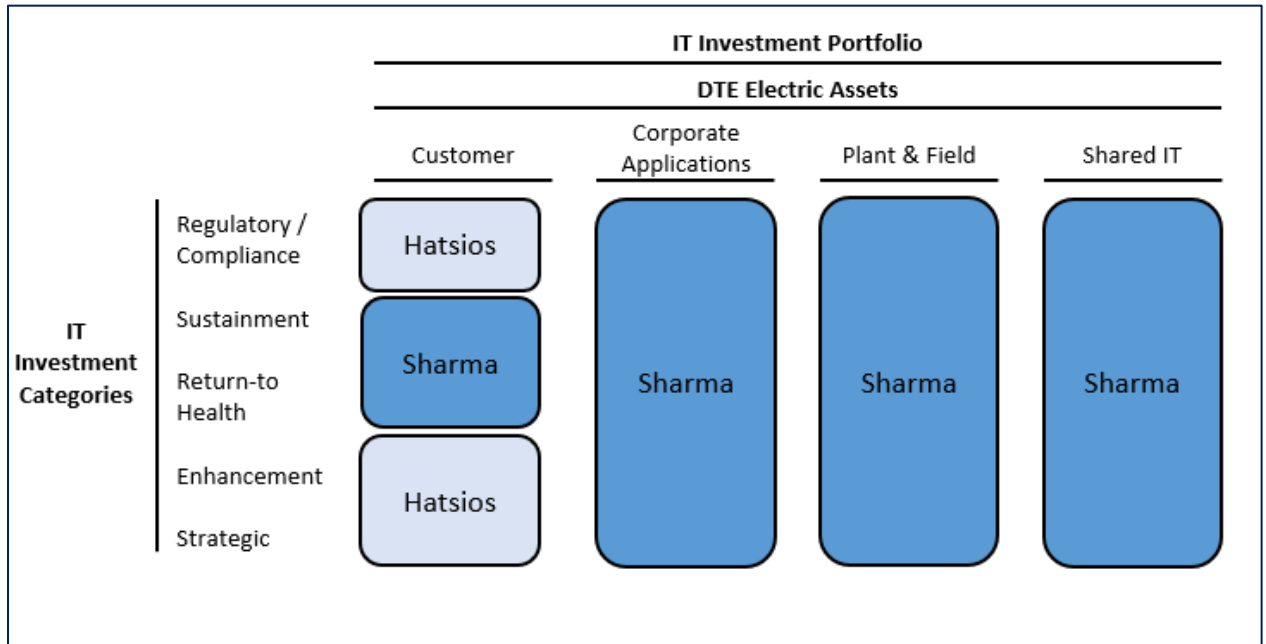
Q19. What is the portfolio structure within the DTE IT organization, and how is it reflected in your testimony?

A19. The DTE Five-Year IT Plan introduces both Portfolio and Category as lenses through which all DTE IT investments can be seen. This matrix can be visualized as seen in Figure 4.

Line
No.

1

Figure 4 IT Investment Portfolio



2

3 **Q20. How are alternate solutions explored for each project or initiative in the**
4 **Investment Planning process?**

5 A20. The Company has adopted a Platform Strategy for its technology decisions over the
6 last several years, where applicable, as reflected in the 5-Year Plan and in recent
7 rate cases. For each new investment represented in my testimony, DTE has
8 considered standard alternatives including moving the investment into the Cloud⁶,
9 foregoing or delaying the investment, or looking outside of the platform for an
10 alternative that has an advantage for our customers or the business unit. In addition
11 to many references of these alternatives throughout my testimony, the Company
12 also addresses alternatives in the business cases themselves. The standard
13 alternatives are:

⁶ Cloud instances are IT infrastructure provided as a service instead of the Company purchasing and maintaining it ourselves. This includes components such as servers, racks, data centers, etc.

Line
No.

- 1 • “Do nothing” within the instant rate case period and defer the activity to a
- 2 future period.
- 3 • Revert to a manual process rather than updating or replacing the existing
- 4 system, where applicable or possible.
- 5 • Select different/competitive/complimentary technology to implement in
- 6 place of the existing solution.
- 7

8 **Q21. Can technology changes impact multiple investments?**

9 A21. Yes. Some technology changes impact many areas. One example is the large-scale
10 effort involved in accommodating a remote workforce that needs collaboration and
11 communication technology to be successful. Because these types of changes cross
12 multiple areas, I have not included them as one large project. Instead, I will mention
13 them as a component of multiple projects that span various areas but are all
14 impacted in varied ways by larger scale change. These will thus appear multiple
15 times throughout my testimony because the obstacles they present are pervasive.

16

17 **Q22. What are the investment categories reflected in the Capital Expenditures - IT**
18 **Summary Exhibit A-12 Schedule B5.7?**

19 A22. The IT investments are categorized into one of the five investment categories,
20 summarized below in Figure 5:

21

Line
No.

1

Figure 5 IT Investment Categories

Regulatory/ Compliance	Required spend due to regulatory requirements
Sustainment	Required spend to 'run' the organization (e.g., basic internal labor, base operating and system maintenance costs)
Return-to- Health	Required investments to update systems that are in critical health or have reached end of life
IT Enhancements	Discretionary capacity/capability performance upgrades to core platforms (e.g., SAP, IT) determined by business needs which are not required for 'keeping the lights on'
Strategic	Strategic spend to unlock a new business capability that can realize value for the organization (e.g., customer satisfaction, increased revenue to offset rate increases, etc.)

2

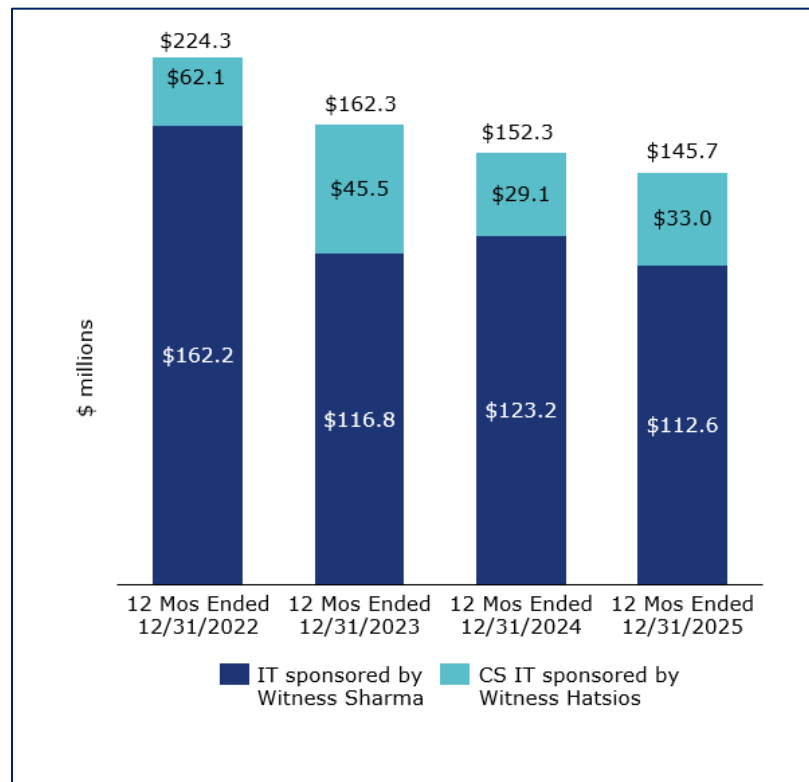
3

Using this nomenclature, I can summarize DTE IT capital both by year and by

4

category as seen in Figures 6 and 7 below.

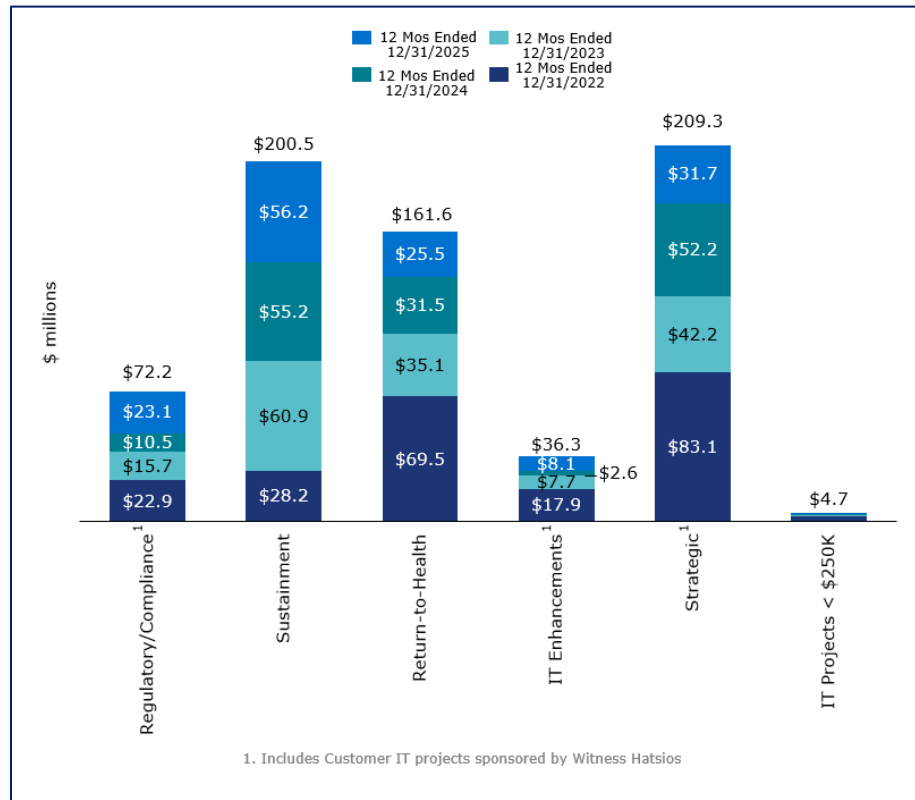
5

Figure 6 DTE Electric IT Capital Expenditure by Period

Line
No.

1

Figure 7 DTE Electric IT Capital Expenditure by Category



2

3 **Q23. Are there any common causes in variance from the prior rate case?**

4 A23. Yes. The IT Department may need to adjust scope and/or re-sequence (adjust
5 schedule) to address high-priority items based on other emerging and higher
6 priority needs. My explanations of historical spend will reflect this prioritization as
7 I explain changes between investment years. The re-sequencing of the scope of an
8 entire project should not be interpreted as the investment is no longer necessary; it
9 is simply a reflection of the operational reality of making investments when there
10 are finite IT resources.

11

12 **Part III- Portfolio Details**

13 **Q24. How is Part III organized?**

Line
No.

1 A24. The Part III is intended to provide a detailed overview of IT capital investments
2 organized into the eight IT portfolios that I discuss in my testimony, as reflected
3 below:

- 4 1. Corporate Applications
- 5 2. Customer Service (Sustainment and Return-to-Health)
- 6 3. Plant & Field
- 7 4. Information Technology for IT (IT for IT)
- 8 5. Information Protection Security (IPS)
- 9 6. Infrastructure Operations
- 10 7. Enterprise Data Analytics
- 11 8. Innovations

12 Within the portfolios, the investments are organized by the investment categories
13 and appear in the same order as they do in the corresponding capital Exhibit A-12
14 B5.7.1 through B5.7.9.

15

16 **Q25. How does your overall testimony tie to your exhibits?**

17 A25. My testimony presents projects which are traced to corresponding exhibits as
18 outlined below:

- 19 • Exhibit A-12 Schedule B5.7 is a summary view of IT capital cost by portfolio and
20 by investment category.
- 21 • Exhibits A-12 Schedules B5.7.1 through B5.7.9 present the capital spend in the
22 historical, bridge, and projected test periods within each portfolio. I have structured
23 my testimony to address IT projects, under the portfolio they support, in the same
24 order we present the portfolios and projects in these exhibits, for each project more
25 than \$250,000.

Line
No.

- 1 • Exhibit A-24, Schedule N1 presents the executive summaries for each business case
2 associated with each project over \$250,000. Exhibit A-24, Schedule N1 tracks to
3 the same order of projects as Exhibit A-12 Schedules B5.7.1 through B5.7.9. I also
4 provide the corresponding business cases for each project in my workpapers.
- 5 • Exhibit A-24 Schedule N3 provides a greater level of detail in the format requested
6 by Commission Staff, as set forth in new filing requirements adopted in the May
7 18, 2023 Order in Case No. U-18238. Each of these IT projects is presented by year
8 and then in portfolio/project order.
- 9 • All variance commentary provided within the testimony will reconcile to Exhibit
10 A-12 Schedules B5.7 - B5.7.9. Where additional recovery is being requested, please
11 refer to Exhibit A-24 Schedule N2.

12

13 **Q26. Are there any IT projects that have already been approved for cost recovery**
14 **in previous rate cases with no additional spend being requested in the instant**
15 **case?**

16 A26. Yes, the following projects in Table 1, for which I provided testimony, and which
17 were approved for cost recovery in Case Nos. U-21297 & U-20836, are not
18 described further in my testimony in the instant case.

19 **IT Projects Approved in U-21297 & U-20836**

Project Name	Portfolio	Category	U-21534 Exhibit Reference	Previous Exhibit Reference
Enterprise Applications Health	Corporate Applications	Sustainment	Line 4, A-12 B5.7.1	Line 3, A-12 B5.7.1, U-21297
Core ERP Data Archiving	Corporate Applications	Return-to-Health	Line 10, A-12 B5.7.1	Line 9, A-12 B5.7.1, U-21297
SOTeria Safe Worker Observations (SWO)	Corporate Applications	IT Enhancements	Line 13, A-12 B5.7.1	Line 12, A-12 B5.7.1, U-21297
PowerPlan Upgrade	Corporate Applications	IT Enhancements	Line 12, A-12 B5.7.1	Line 11, A-12 B5.7.1, U-21297

Line
No.

Enterprise Automation	Corporate Applications	Strategic	Line 15, A-12 B5.7.1	U-20836 A-12 B5.8, Line 8 Sponsored by witness Uzenski.
Distributed Generation Upgrades	Customer Service	Return-to-Health	Line 22, A-12 B5.7.2	Line 22, A-12 B5.7.2, U-21297
Migrate IVR to the Cloud	Customer Service	Return-to-Health	Line 23, A-12 B5.7.2	Line 18, A-12 B5.7.3, U-21297
Systems, Applications, and Products (SAP) Enhancement Program	Customer Service	Return-to-Health	Line 24, A-12 B5.7.2	Line 23, A-12 B5.7.2, U-21297
Network Reliability and Monitoring	Plant and Field	Sustainment	Line 11, A-12 B5.7.4	Line 9, A-12 B5.7.4, U-21297
Cable Routing Application (CRA) Replatform	Plant and Field	Return-to-Health	Line 18, A-12 B5.7.4	Line 17, A-12 B5.7.4, U-21297
DO Business Warehouse (DOBW) Replacement	Plant and Field	Return-to-Health	Line 20, A-12 B5.7.4	Line 20, A-12 B5.7.4, U-21297
Fuel Supply-Plant Fuel Management System	Plant and Field	Return-to-Health	Line 23, A-12 B5.7.4	Line 20, A-12 B5.7.4, U-21297
Meter Data Management (MDM) Consolidation	Plant and Field	Return-to-Health	Line 25, A-12 B5.7.4	Line 22, A-12 B5.7.4, U-21297
P3M Heat Rate Calculation and GADS Reporting Functions	Plant and Field	Return-to-Health	Line 26, A-12 B5.7.4	Line 23, A-12 B5.7.4, U-21297
Plant & Field Document Repository	Plant and Field	Return-to-Health	Line 27, A-12 B5.7.4	Line 24, A-12 B5.7.4, U-21297
Replace DO Lines – SOC Radio	Plant and Field	Return-to-Health	Line 28, A-12 B5.7.4	Line 25, A-12 B5.7.4, U-21297
ESRI Application Health	Plant and Field	Return-to-Health	Line 22, A-12 B5.7.4	Line 18, A-12 B5.7.4, U-21297
Fermi Enhancements	Plant and Field	Strategic	Line 30, A-12 B5.7.4	Line 28, A-12 B5.7.4, U-21297
Integrated Information Resource (I2R) Replacement	Plant and Field	Strategic	Line 32, A-12 B5.7.4	Line 30, A-12 B5.7.4, U-21297
Maximo Engineering Process Automation	Plant and Field	Strategic	Line 33, A-12 B5.7.4	Line 31, A-12 B5.7.4, U-21297
Maximo HSE Support	Plant and Field	Strategic	Line 34, A-12 B5.7.4	Line 32, A-12 B5.7.4, U-21297
Primavera Modernization	Plant and Field	Strategic	Line 35, A-12 B5.7.4	Line 34, A-12 B5.7.4, U-21297

Line
No.

IT for IT Tools	IT for IT	IT Enhancements	Line 2, A-12 B5.7.5	Line 10, A-12 B5.7.5, U-21297
Application Portfolio Management- APM	IT for IT	Strategic	Line 3, A-12 B5.7.5	Line 11, A-12 B5.7.5, U-21297
IT Service Management Tool	IT for IT	Strategic	Line 5, A-12 B5.7.5	Line 27, A-12 B5.7.5, U-21297
Automating Database Event Log Monitoring	Infrastructure Operations	Regulatory / Compliance	Line 1, A-12 B5.7.7	Line 1, A-12 B5.7.5, U-21297
Ashley Mews Closure and Relocation	Infrastructure Operations	Sustainment	Line 3, A-12 B5.7.7	Line 2, A-12 B5.7.7, U-21297
Virtual Desktop Infrastructure (VDI)	Infrastructure Operations	Return-to-Health	Line 29, A-12 B5.7.7	Line 20, A-12 B5.7.7, U-21297
Afaria Upgrade / Replacement	Infrastructure Operations	IT Enhancements	Line 31, A-12 B5.7.7	Line 8, A-12 B5.7.5, U-21297
Wide Area Network Redesign Session Initiation Protocol (SIP) Backhaul	Infrastructure Operations	IT Enhancements	Line 34, A-12 B5.7.7	Line 21, A-12 B5.7.7, U-21297
Network Operations Center (NOC) Automation	Infrastructure Operations	Strategic	Line 46, A-12 B5.7.7	Line 30, A-12 B5.7.5, U-21297

1

2 **Corporate Applications**3 **Q27. Can you describe the Corporate Applications portfolio?**

4 A27. The Corporate Applications portfolio encompasses assets used by the enterprise to
5 execute critical internal business functions. It supports business units such as
6 Human Resources, Finance and Controller, Legal, Supply Chain, Fleet & Facilities,
7 and IT assets used by the entire enterprise. In addition, Corporate Applications
8 portfolio provides Enterprise Automation solutions for the enterprise. The
9 investments within Corporate Applications span the 5 investment categories
10 outlined/described above and the specific projects are detailed in the section below.

11

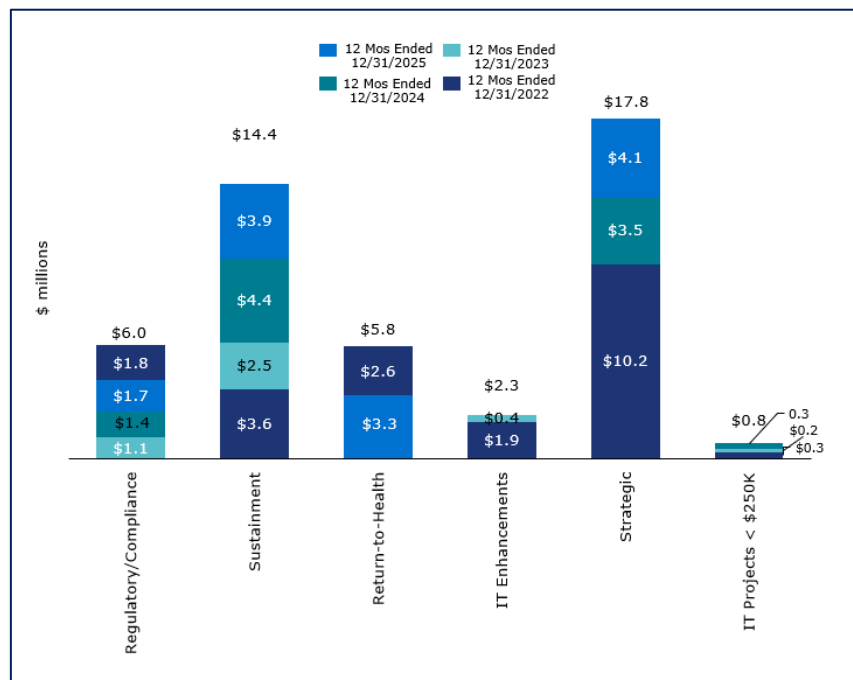
12 **Q28. What are the projected costs for investments in the Corporate Applications**
13 **Portfolio?**

Line
No.

1 A28. As reflected on Line 2 of Exhibit A-12 Schedule B5.7, page 1, capital expenditures
2 for Corporate Applications total \$17.1 million for the historical test year ended
3 December 31, 2022, \$17.7 million in the projected bridge period 24 months ending
4 December 31, 2024, and \$12.4 million for the projected test period ending
5 December 31, 2025.

6 The individual initiatives that fall into this area appear in Exhibit A-12 Schedule
7 B5.7.1. The synopses below provide the total spend for each line item the Company
8 requests in the instant case, and the details regarding breakout by historical period,
9 projected bridge period, and projected test period, are each laid out in Exhibit A-12
10 Schedule B5.7.1, in columns d, g and h, respectively. Figure 8 represents a high-
11 level view of capital allocation within the portfolio.

12 **Figure 8 Corporate Applications – IT Investment**



13

Line
No.

1 Regulatory/Compliance

2 **Q29. Can you explain in detail the Corporate Applications investments in the**
3 **Regulatory and Compliance category?**

4 A29. The portfolio will invest \$4.9 million in the Regulatory/Compliance category in the
5 project described below:

6

7 **Core ERP Stacks and Packs**

8 • The Company will invest \$4.9 million in the **Core ERP Stacks and Packs** project
9 over the course of 36-months ending December 31, 2025, and has a historical spend
10 of \$1.1 million as shown on line 1 of Exhibit A-12 Schedule B5.7.1.

11 The Core ERP Stacks and Packs project is a recurring annual investment to ensure
12 the Core Enterprise Resource Planning platform is up to date with the latest required
13 support packs and stacks. The Enterprise Resource Planning system (ERP) is a core
14 platform that supports all resource planning processes and systems supported
15 through the SAP platform for the Corporate Services, Human Resources (HR), and
16 Finance organizations. Examples of critical processes that are supported are
17 Financial Close, Financial Asset Management, Financial Reporting, Time
18 Management, Payroll Processing, Purchasing, and Tax Management. There are also
19 critical integrations that support Customer Billing and Asset and Work
20 Management. The system must be upgraded with the latest Human Resources
21 updates from vendor SAP in order to run year-end payroll, produce W-2s and
22 comply with mandatory State, local, and Federal reporting.

23 The annual investment from 2022 to 2024 was approved for cost recovery in U-
24 21297. See Exhibit A-24 N3 Line 4 for additional project details for the 2025
25 spend.

26

Line
No.

1 Sustainment

2 **Q30. Can you explain in detail the Corporate Applications investment in the**
3 **Sustainment category?**

4 A30. The portfolio will invest \$10.8 million in the Sustainment category over the course
5 of 36-months ending December 31, 2025, as shown in line 2 through line 8 of the
6 Capital Expenditures - Exhibit A-12 Schedule B5.7.1. The planned costs are
7 primarily across projects discussed further below:

8

9 **Corporate Services Application Health**

- 10 • The Company will invest \$2.1 million in the **Corporate Services Application**
11 **Health** project over the course of 36-months ending December 31, 2025, and has a
12 historical spend of \$0.5 million in 2022, as shown on line 2 of Exhibit A-12
13 Schedule B5.7.1.

14 Corporate Services Application Health is an ongoing and annual investment to
15 upgrade applications running on unsupported infrastructure and operating systems
16 to ensure the health and stability of a suite of 36 applications within the portfolio to
17 support organizations such as Supply Chain, Environmental Management and
18 Safety, and the overall health, reliability, and security of our corporate services
19 applications such as mail services, fleet and fuel management, and emissions
20 monitoring. The Company will continue to invest in the 36 applications, making
21 the necessary system changes required by the business units, implementing
22 hardware and environment upgrades, continuing information security
23 enhancements, and implementing vendor software changes. This ongoing annual
24 investment ensures IT assets avoid outages or disruption to business processes that
25 may occur due to IT component failure, security issues, incompatibility with newer
26 components, and appropriate vendor support is maintained.

Line
No.

1 The annual investment from 2022 to 2024 was approved for cost recovery in U-
2 21297. See Exhibit A-24 N3 Line 8 for additional project details.

3

4 **Documentum (EDM) Application Health**

- 5 • The Company will invest \$0.9 million in the **Documentum (EDM) Application**
6 **Health** project over the course of 36-months ending December 31, 2025, as shown
7 on line 3 of Exhibit A-12 Schedule B5.7.1.

8 This project represents the year over year investment that will be required in the
9 Documentum platform including yearly capital investments to account for security
10 vulnerability remediation, system upgrades, value added enhancements, and
11 organic system growth (sizing). A Document Management Governance Board has
12 been established to define an aligned strategy that addresses gaps in how documents
13 are received, processed, reviewed, approved, stored, retrieved, and eventually
14 purged.

15 This investment will ensure that the system meets the operational and availability
16 goals for which it was implemented and remains secure and available to meet
17 document repository objectives. These objectives will support our defined
18 document management strategy which spans across business units.

19 The Company reflects a variance of \$0.1 million less in the 12 months ending
20 December 31, 2024, than was approved for cost recovery in U-21297. This cost
21 reduction was a result of decreased external labor cost with the new vendor.

22 The investment from 2023 to 2024 was approved for cost recovery in U-21297.
23 See Exhibit A-24 N3 Line 811 for additional project details.

24

Line
No.

1 **Enterprise Resource Planning**

- 2 • The Company will invest \$2.9 million in the **Enterprise Resource Planning**
3 project over the course of 36-months ending December 31, 2025, and has a
4 historical spend of \$1.2 million in 2022 as shown on line 5 of Exhibit A-12
5 Schedule B5.7.1.

6 The Enterprise Resource Planning system (ERP) is a core platform that supports all
7 resource planning processes and systems supported through the SAP platform for
8 the Corporate Services, Human Resources, and Finance organizations.

9 This investment supports the non-regulatory and compliance requirements such as
10 monthly releases to upgrade end-of-life systems, complete required critical system
11 failover testing, and enhance associated applications with changing business
12 processes in each of these organizations.

13 The annual investment from 2022 to 2024 was approved for cost recovery in U-
14 21297. See Exhibit A-24 N3 Line 18 for additional project details.

15

16 **Financial Applications Health**

17 The Company will invest \$0.8 million in the **Financial Applications Health**
18 project over the course of 36-months ending December 31, 2025, and has a
19 historical spend of \$0.4 million in 2022 as shown on line 6 of Exhibit A-12
20 Schedule B5.7.1. This project represents periodic updates which include significant
21 capital investment in environment upgrades to maintain the health, reliability, and
22 security of our financial systems and covers 21 unique applications under the
23 financial applications portfolio. The Company reflects a variance of \$0.3 million
24 more in the 12 months ending December 31, 2024, due to an additional \$298K
25 spend in 2022 to support PowerPlan Uplift vendor fees.

Line
No.

1 The annual investment from 2022 to 2024 was approved for cost recovery in U-
2 21297. See Exhibit A-24 N3 Line 22 for additional project details.

3

4 **Human Resources Applications Health**

- 5 • The Company will invest \$0.9 million in the **Human Resources Applications**
6 **Health** project over the course of 36-months ending December 31, 2025, and has a
7 historical spend of \$0.6 million in 2022, as shown on line 7 of Exhibit A-12
8 Schedule B5.7.1.

9 Human Resources Applications Health investment is annual and ongoing to ensure
10 the health and stability of applications within the Human Resources portfolio, such
11 as the SuccessFactors Platform, OpenText, and Oracle backends. This project will
12 cover the required upgrades on these applications to ensure they are running on
13 supported infrastructure and that operating systems are replaced as required. SAP
14 requires yearly upgrades and SuccessFactors require bi-annual upgrades to ensure
15 each platform is current and operating with the latest functions and features to
16 support business processes. This project also supports the application configuration
17 changes to be built, tested, and deployed through monthly change release to support
18 HR business process requirements.

19 The Company reflects a variance of \$0.4 million more in the 36 months ending
20 December 31, 2024, than was approved for recovery in U-21297. This is primarily
21 due to the additional spend in 2022 as explained below.

22 In 2022 this project required additional scope to deliver the following functionality
23 in the HR SuccessFactors:

- 24 • Enhanced Learning Management System reporting allows updated reporting and
25 analysis to ensure employees have the timely training and skills to perform their
26 jobs.

Line
No.

- 1 • Preferred name implementation
- 2 • Employee file management improved DTE's ability to manage larger volumes of
- 3 workforce-related records, while maintaining compliance with document retention,
- 4 deletion regulation, and allowing searches on all personnel activities and processes
- 5 to be performed more efficiently.

6 The annual investment from 2022 to 2024 was approved for cost recovery in U-
7 21297. See Exhibit A-24 N3 Line 26 for additional project details.

8

9 **Production Growth**

- 10 • The Company will invest \$2.2 million in the **Production Growth** project over the
- 11 course of 36-months ending December 31, 2025, and has a historical spend of \$0.5
- 12 million in 2022, as shown on line 8 of Exhibit A-12 Schedule B5.7.1.

13 The Production Growth project addresses the ongoing increase in the size and
14 capability of our computing environment as our on-premise Corporate Application
15 systems expand to meet the demands of our business. This investment primarily
16 covers server and storage capacity needed by existing business systems. The annual
17 server storage, capacity, and memory growth for the Corporate Application
18 portfolio, for example, in 2020 was approximately 11 TB storage and 16 GB of
19 memory across all environments (test and development). The annual budget for
20 these increases is based on the historical consumption performance and growth. In
21 2022, the growth was approximately 8 TB storage, 16 GB of memory and 1.1 GHz
22 CPU across all environments.

23 The annual investment from 2022 to 2024 was approved for cost recovery in U-
24 21297. See Exhibit A-24 N3 Line 30 for additional project details for the 2025
25 spend.

26

Line
No.

1 Return-to-Health

2 **Q31. Can you explain in detail the Corporate Applications investment in the**
3 **‘Return-to-Health’ category?**

4 A31. The portfolio will invest \$5.8 million in the Return-to-Health category over the
5 course of 36-months ending December 31, 2025, as shown in lines 9 to 11 of the
6 Capital Expenditures - Exhibit A-12 Schedule B5.7.1. The planned costs are spread
7 across projects that are as discussed below:

8

9 **Cloud Health and Safety**

- 10 • The Company will invest \$3.1 million in the **Cloud Health and Safety** project over
11 the course of 36-months ending December 31, 2025, as shown on line 9 of Exhibit
12 A-12 Schedule B5.7.1.

13 The current DTE Energy safety reporting systems are not integrated and contain
14 minimal workflow capabilities resulting in lagging safety information which is used
15 for internal metrics. To return the Company’s safety reporting capabilities to health
16 the Company will design, configure, test, and deploy a Software as a Service (SaaS)
17 SAP solution. The SAP solution will improve reporting on near-miss and unsafe
18 working conditions along with consolidating multiple systems for recording
19 Potential Serious Injury and Fatality (PSIFs) into a single system. It will further
20 improve security role compliance/access by minimize the potential for human error
21 on entering data into multiple systems. The solution will support monitoring which
22 enables the company to efficiently detect data security threats, secure data for
23 HIPAA regulations, and mitigate potential sources of data breaches by having a
24 single system to safeguard access. The solution will also enable dynamic form entry
25 which both employees and contractors can access.

Line
No.

1 The 2024 spend was approved for cost recovery in U-21297. See Exhibit A-24 N3
2 Lines 31-32 for additional project details.

3

4 **Source to Pay (S2P) Transformation**

- 5 • The Company will invest \$2.0 million in the **Source to Pay (S2P) Transformation**
6 project over the course of 12 months ending December 31, 2025, as shown on line
7 11 of Exhibit A-12 Schedule B5.7.1.

8 This project will replace the existing SAP SRM outdated software with cloud-based
9 technology that directly integrates with ECC and the S4 Hana application. SAP has
10 not invested in their current purchase to pay (P2P) functionality Supplier
11 Relationship Manager (SRM) product in nine years. The purchasing business
12 process and system required to support our customer commitments, storm activities
13 and power distribution and generation operations are relying on old technologies
14 such as email, fax and manual created reports or dashboards to measure and
15 maintain the materials and services to keep our organization running. In 2027, the
16 SAP support for our current Enterprise Resource Planning Central Component
17 (ECC) financial system and SRM purchasing system will expire. The two-year
18 effort to replace the purchase to pay system and implement modernized process
19 should be completed prior to the upgrade of the SAP ECC financial to reduce risk.
20 See Exhibit A-24 N3 Line 34 for additional project details.

21

22 IT Enhancements

23 **Q32. Can you explain in detail Corporate Applications investment in the IT**
24 **Enhancements category?**

25 A32. The portfolio will invest \$0.4 million in the IT Enhancement category over 36-
26 months ending December 31, 2025, as shown in lines 12 to 14 of the Capital

Line
No.

1 Expenditures - Exhibit A-12 Schedule B5.7.1. The planned costs are across
2 projects that are as discussed further below:

3

4 **SuccessFactors Program**

- 5 • The Company will invest \$0.3 million in the **SuccessFactors Program** project over
6 the course of 12-months ending December 31, 2024 and has a historical spend of
7 \$0.2 million in 2022 as shown on line 14 of Exhibit A-12 Schedule B5.7.1.

8 The multi-year program involves the gradual release of features/modules in the
9 SuccessFactors platform in multiple areas.

10 The Company will implement the SuccessFactors Cross board and Peoplesoft
11 queries, which provides a streamlined business process for the HR business partner
12 to hire (onboard), terminate (offboard) and internally transfer (cross-board)
13 employees. In today's environment, the HR process to internally transfer or
14 terminate an employee is managed outside of the SuccessFactors platform and is
15 not tied to the existing employee records. This results in HR being unable to
16 monitor process timing and number of employees impacted.

17 The Company reflects a variance of \$0.1 million less in the 36 months ending
18 December 31, 2024, than was approved for cost recovery in U-21297 as explained
19 below.

20 In 2022, the project re-sequenced work to ensure business process development
21 was completed in advance of technology implementation of Employee Central (EC)
22 Shared Service Center scope. This schedule adjustment has been reflected in the
23 projected spend completing in 2023.

24 The 2022, 2023 spend was approved for cost recovery in U-21297. See Exhibit A-
25 24 N3 Lines 39-40 for additional project details.

26

Line
No.

1 Strategic

2 **Q33. Can you explain in detail Corporate Applications investment in the Strategic**
3 **category?**

4 A33. The Company will invest \$7.6 million in the Strategic category over the course of
5 36-months ending December 31, 2025, as shown in lines 15 through 20 of the
6 Capital Expenditures - Exhibit A-12 Schedule B5.7.1. The planned costs are
7 primarily across projects that are as discussed further below:

8

9 **Enhanced Document Management Capability**

- 10 • The Company will invest \$4.2 million in the **Enhanced Document Management**
11 **Capability Projects** project over the course of 36-months ending December 31,
12 2025, as shown on line 16 of Exhibit A-12 Schedule B5.7.1.

13 This project will begin in 2024 and address significant functional improvements in
14 how documents are received, processed, reviewed, approved, stored, retrieved, and
15 eventually purged. The areas of focus are automation of document workflow to
16 streamline business processes consistently and integration of documents to work
17 management tools & other systems. Defining a common document management
18 strategy that can span across all Plant & Field BU's and addresses gaps in how
19 documents are received, processed, reviewed, approved, stored, retrieved, and
20 eventually purged. These changes will impact all plant and field employees in
21 Fossil Generation, Renewables, DO, and Gas. Expected time savings estimated at
22 200,000 man-hours a year. These efficiency gains are expected to be achieved by
23 all business department users.

24 The Company reflects a variance of \$2.0 million less in the 12 months ending
25 December 31, 2024, than was approved for cost recovery in U-21297. This is

Line
No.

1 primarily due to a schedule and cost shift from 2024 to 2025, to an adjusted
2 implementation plan start project in 2024 with a project completion in 2026.

3 See Exhibit A-24 N3 Lines 42-43 for additional project details.

4

5 **Organizational Management Optimization**

- 6 • The Company will invest \$0.5 million in the **Organizational Management**
7 **Optimization** project over the course of 12-months ending December 31, 2024, as
8 shown on line 17 of Exhibit A-12 Schedule B5.7.1.

9 In 2017, the Company implemented Success Factors (SF) and integrated the
10 solution with SAP on Premise. In order to keep cost down for the initial
11 implementation in 2017, the replication of data between the two systems was
12 required to be completed manually. Since 2017, this has required 1 Full Time
13 Equivalent dedicated to manual replication and has impacted the productivity of
14 HR staffing in replication downstream process impacts. In order to optimize
15 operating cost and meet customer affordability targets the Company must invest in
16 streamlining all business processes. In response to these challenges, this project
17 will optimize organization management process within SuccessFactors by
18 removing the manual replication requirements between SuccessFactors and SAP
19 on premise, resulting in 100% reduction in replication errors and data mismatches
20 of 500 or more per month, 30% efficiency in downstream process improvements
21 and achieve productivity gains of 2 full time equivalents.

22 See Exhibit A-24 N3 Line 44 for additional project details.

23

Line
No.

1 **SAP Employee Central Payroll**

- 2 • The Company will invest \$0.9 million in the **SAP Employee Central Payroll**
3 project over the course of 12-months ending December 31, 2025, as shown on line
4 18 of Exhibit A-12 Schedule B5.7.1.

5 This project will implement the SAP Employee Central Payroll application to
6 replace the current SAP ERP payroll system implemented in April 2007. Our
7 current SAP ERP application houses a built-in Payroll application; however, SAP
8 is phasing out SAP ERP application and replacing it with SAP S4 Hana application
9 by 2027. However, SAP S4 Hana does not have a built-in payroll system.
10 Therefore, SAP SuccessFactors Payroll, an eighteen-month initiative, requires
11 implementation starting in 2024 as a predecessor project, to avoid delaying the start
12 of the S4 Hana implementation. It is prudent for the Company to make this
13 investment at this time as the future S4 Hana implementation project, which will
14 take 2 years to implement (requiring the same environments and resources to
15 implement), to ensure critical business processes are still operating on a supported
16 platform by SAP S4 Hana in 2027. The cloud-based SAP Payroll application will
17 be configured, tested, and integrated with multiple business unit interfaces, external
18 interfaces, and our third-party business systems.

19 The Company reflects a variance of \$0.8 million less in the 36 months ending
20 December 31, 2024, than was approved for cost recovery in U-21297. This is
21 primarily due to a schedule change from original project start 2024 and original
22 project finish 2025 to revised project finish date in 2026 in order to align with Time
23 Entry project dependencies. Employee Time entry is the practice of monitoring and
24 documenting the hours that each employee works. The Company tracks work hours
25 by requiring employees to enter time in the SAP time management system which

Line
No.

1 sends information to SAP payroll. Aligning this project with Time Entry allows
2 will optimize integration and capability testing and deployments.
3 See Exhibit A-24 N3 Line 45 for additional project details.

4

5 **Talent System Optimization**

- 6 • The Company will invest \$0.3 million in the **Talent System Optimization** project
7 over the course of 12-months ending December 31, 2025, as shown on line 19 of
8 Exhibit A-12 Schedule B5.7.1.

9

10 The Talent Management Optimization has several benefits: it builds a high-
11 performance workplace by improving Diversity, Equity and Inclusion engagement
12 score from 4.1 to 4.3, and a 5% increase in the adoption of learning programs; it
13 fosters a learning climate; it adds value to the employer brand, and it improves
14 diversity. The talent management module will enable a connection for employee
15 development throughout the SuccessFactors system, allowing employees to see a
16 clear career path including opportunities for learning, assignments and skill and
17 competency assessments.

18 The Company's IT (SuccessFactors modules) systems are currently set up to work
19 independently of one another, not connecting an individual's skills and
20 competencies with learning, career pathing, or any other talent process. In today's
21 competitive talent environment, it is important for the Company to invest in talent
22 management because employees expect a clear development plan for their career
23 aspirations. The optimization of the system will be more effective in attracting and
24 retaining talent. With the system fully optimized, the Success Factors platform will
25 be able to provide this functionality.

26 See Exhibit A-24 N3 Line 46 for additional project details.

Line
No.

1

2 **Transparency Electric Data**

- 3 • The Company will invest \$1.8 million in the **Transparency Electric Data** project
4 over the course of 12-months ending December 31, 2024, as shown on line 20 of
5 Exhibit A-12 Schedule B5.7.1.

6 The electric grid has seen an increased strain from severe weather events leading to
7 customer outages. The Company's customers and stakeholders are increasingly
8 seeking more robust data on both grid reliability and planned investments.
9 Importantly, customers and stakeholders have expressed a desire to have this data
10 provided in a localized manner, so that customers or communities can understand
11 circuit(s) performance and investments in their neighborhoods. To meet this need
12 in a way that allows our customers and stakeholders ready access to localized data
13 on grid performance and grid investments, the project sets out to accomplish the
14 following:

- 15 1. Design and develop an improved intuitive, easy-to-find, and customer-
16 friendly Electric Grid Investment Map. This will offer our customers and
17 community stakeholders readily accessible and hyper-localized visibility
18 into the investments the Company is making to improve grid reliability.
19 Customers will have improved visibility into the types of work being done
20 in their neighborhood as well as the projected timelines for that work's
21 completion. In addition, customers will have access to localized reliability
22 data that will help customers and stakeholders easily assess the relative
23 performance of their circuit(s).
- 24 2. Design and develop an easy-to-use, flexible, "one-stop shop" platform that
25 simplifies reliability and investment data access between internal business
26 units. This enables easy and quick capability for internal personnel to use

Line
No.

1 readily available data for community stakeholder engagement. This also
2 ensures data is accurate, current, and consistent so that it meets the needs of
3 our customers and stakeholders.

4 See Exhibit A-24 N3 Line 47 for additional project details.

5

6 **Customer Service**

7 **Q34. Can you describe the Customer Service Portfolio?**

8 A34. The Customer Service Portfolio is made up of key systems integrating with the
9 Company's SAP Customer Relationship and Billing (CR&B) platform.
10 Investments in the Customer Service portfolio directly impact the Company's
11 interactions with our customers. I will discuss the IT capital investment in
12 Sustainment and Return-to-Health categories in my testimony below. Company
13 Witness Hatsios discusses the capital investments in the Regulatory/Compliance,
14 IT Enhancements and Strategic categories in detail in his testimony in the instant
15 case.

16

17 **Q35. What are the projected costs for investments in the Customer Service**
18 **Portfolio?**

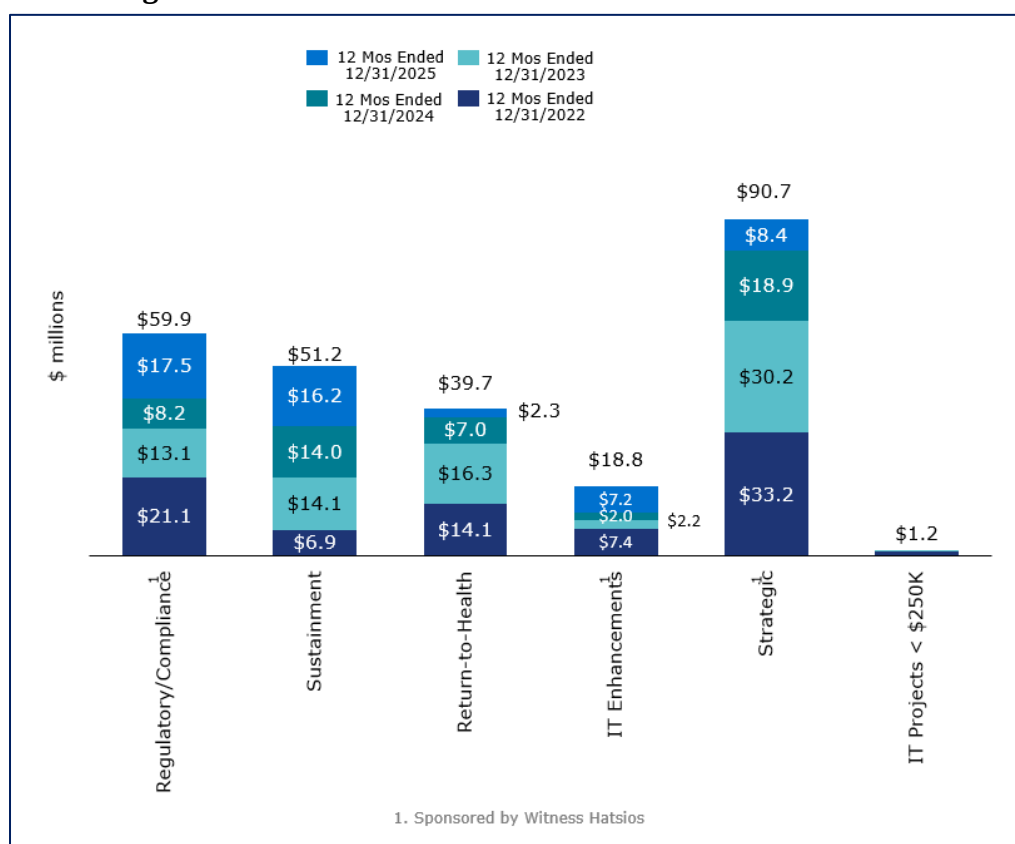
19 A35. As reflected on line 3 of Exhibit A-12 Schedule B5.7, page 1, capital costs for the
20 Sustainment and Return to Health category investments in Customer Service
21 Portfolio total \$21.6 million for the historical test year ending December 31, 2022,
22 \$51.5 million in the bridge period (for the 24 months ending December 31, 2024),
23 and \$18.5 million for the projected test period ending December 31, 2025.
24 The individual initiatives that fall into this area appear in Exhibit A-12 Schedule
25 B5.7.2. The synopses below provide the total spend for each line item the Company

Line
No.

requests in this rate case and the details regarding breakout by historical period, projected bridge period, and projected test period, are each laid out in Exhibit A-12 Schedule B5.7.2, in columns d, g and h, respectively. Figure 9 represents a high-level view of capital allocation within the portfolio.

IT dollars depicted in Exhibit A-12 Schedule B5.7.3 are in support of the Customer Service Organization and reflect investments discussed by Witness Hatsios.

Figure 9 Customer Service– IT Investment



Sustainment

Q36. Can you explain in detail Customer Service investments in the Sustainment category?

A36. The Company will invest \$44.3 million in the Sustainment category over the course of 36-months ending December 31, 2025, as shown in lines 1 through 14 of the

Line
No.

1 Capital Expenditures Exhibit A-12 Schedule B5.7.2. The planned costs are across
2 projects that are as discussed further below:

3

4 **Automated Application Monitoring Health**

- 5 • The Company will invest \$1.1 million in the **Automated Application Monitoring**
6 **Health** project over the course of 36-months ending December 31, 2025 and has a
7 historical spend of \$0.6 million in 2022, as shown on line 1 of Exhibit A-12
8 Schedule B5.7.2.

9 Today, the Company has deployed several modules from the SAP Solution
10 Manager application. These modules provide visibility across multiple systems,
11 SAP Process Integration, SAP Customer Relationship Management, SAP Industry
12 solution for utilities, SAP Business Warehouse etc. These modules do not have a
13 built-in solution to support operational monitoring of potential system failure
14 points. This project will add Solution Monitoring, End User Experience
15 Monitoring, Dynatrace Monitoring, and SAP Solution Manager. These features
16 will provide additional Monitoring, Optimize Alerting & Notifications, Improve
17 Standard Operational Procedures, Data Volume Management, and Analytics and
18 Dashboards. It will provide precise visibility across systems. The SAP Solution
19 Manager systems also require ongoing operational asset health upgrades to
20 maintain the overall reliability and availability of the infrastructure hosting the
21 application. These upgrades provide foundation for application changes due to
22 evolving business processes and security compliance updates.

23 The Company reflects a variance of \$0.3 million more in the 36 months ending
24 December 31, 2024, than was approved for cost recovery in U-21297. This is
25 partially due to \$0.17 million increase in 2023 as a result of the first quarter
26 catastrophic storm which required an increased scope to improve monitoring and

Line
No.

1 resiliency of core critical applications (Customer Relationship Management,
2 Industry Solution for Utilities, and Process Orchestration) related to outage
3 management.

4 The 2022-2024 spend was approved for cost recovery in U-21297. See Exhibit A-
5 24 N3 Line 51 for additional project details.

6

7 **Business Planning and Development (BPD) and Electric Sales & Marketing (ESM)**
8 **Application Health**

- 9 • The Company will invest \$2.4 million in the **Business Planning and Development**
10 **(BPD) and Electric Sales & Marketing (ESM) Application Health** project over
11 the course of 36-months ending December 31, 2025, and has a historical spend of
12 \$0.4 million in 2022, as shown on line 2 of Exhibit A-12 Schedule B5.7.2.

13 The BPD and ESM project supports annual refresh of 12 IT assets that support the
14 operations of Corporate Energy Forecasting, Integrated Resource Planning,
15 Demand Response, Community Lighting, Joint Use, and Customer Choice. These
16 departments and the associated applications support the Company's ability to
17 effectively forecast system load for planning purposes and provide customers with
18 alternative rates and products that assist them with managing their energy usage.
19 This project provides the resources and services to complete required application
20 software upgrades and hardware replacements, the development, testing and
21 deployment of enhancements to improve functionality and performance required
22 by business process changes, and end of life replacement of legacy operating
23 systems, hardware, and cloud based virtual systems. Finally, investments in
24 mitigation of security vulnerabilities are planned for as required.

25 The 2022-2024 spend was approved for cost recovery in U-21297. See Exhibit A-
26 24 N3 Line 55 for additional project details.

Line
No.

1

2 **Contact Center Application Health**

- 3 • The Company will invest \$3.8 million in the **Contact Center Application Health**
4 project over the course of 36-months ending December 31, 2025, and has a
5 historical spend of \$1.1 million in 2022, as shown on line 3 of Exhibit A-12
6 Schedule B5.7.2.

7 The Contact Center IT portfolio includes 17 IT-supported applications across the
8 contact center telephony and interactive voice response (IVR) functions, four of
9 which are critical, and approximately 210 technology components consisting of
10 servers (both physical and virtual), operating systems, and databases that are
11 required to run day-to-day activities. This portfolio of systems allows customers to
12 call DTE's main 1-800 phone number, interact with the IVR system for self-service
13 if desired, and be properly routed to a Contact Center customer representative (CR)
14 with the ability to resolve the customer's inquiry or process their request / order
15 when needed. In addition, this portfolio provides the tools and support for the
16 Contact Center to manage and administer both the IVR and call handling systems.
17 The Company reflects a variance of \$3.6 million less in the 36 months ending
18 December 31, 2024, than was approved for cost recovery in U-21297.

19 In 2024, this project included scope to renew the Avaya Telephony contract.
20 However, through the Migrate IVR to the Cloud project it was determined that in
21 2024 the Company will be replacing the Avaya solution and will no longer be
22 required to extend the licenses purchase resulting in the variance above.

23 The 2022-2024 spend was approved for cost recovery in U-21297. See Exhibit A-
24 24 N3 Line 59 for additional project details.

25

Line
No.

Closed Loop COCL Application Health

- The Company will invest \$1.6 million in the **Closed Loop COCL Application Health** project over the course of 36-months ending December 31, 2025, as shown on line 4 of Exhibit A-12 Schedule B5.7.2.

This project will utilize agile delivery to roll out incremental improvements for customer transactions on the web such as billing, usage, payments, outage, program enrollment, Collections Closed Loop, and MIMO (Move-In/Move-Out) Closed Loop process improvements. In support of the Digital Experience Team, the project team will provide Azure APIM (API Management) including Network configuration, Firewall configuration, access management and managing the API gateway in support of web services, and awareness in system health insight. Additional Dynatrace licenses will be utilized for integrating Azure with Dynatrace and will provide the ability to monitor the customer experience and make necessary adjustments.

The Company reflects a variance of \$0.4 million less in the 36 months ending December 31, 2024, than was approved for cost recovery in U-21297. This is primarily due to cost savings initiatives associated with service providers supporting the projects.

The 2022-2024 spend was approved for cost recovery in U-21297. See Exhibit A-24 N3 Line 63 for additional project details.

Cloud Platform Enterprise Agreement

- The Company will invest \$0.8 million in the **Cloud Platform Enterprise Agreement** project over the course of 12-months ending December 31, 2024, as shown on line 5 of Exhibit A-12 Schedule B5.7.2.

Line
No.

1 The project is to cover a 3-year capital cost for the Cloud Platform Enterprise
2 Agreement (CPEA) which is a business model that allows for the consumption of
3 cloud credits based on actual usage. This agreement originated with the Meter Data
4 Management (MDM) project and its need for SAP FIORI. SAP Fiori is a design
5 system that enables you to create business apps with a consumer-grade user
6 experience, turning casual users into SAP experts with simple screens that run on
7 any device. By using the SAP Fiori design guidelines DTE can easily build and
8 customize our own apps that are consistent with what we use SAP S/4HANA and
9 our other enterprise software solutions. As a result of this service MDM was able
10 to utilize the SAP FIORI Launchpad as an entry point to our back-end SAP system
11 (SAP ISU). Additionally, this platform has been utilized for other critical projects
12 such as Agency Website (an agency portal for assisting customer energy needs),
13 Damage Claim and Document Signature lending the capability to use the Business
14 Technology Platform services available under the CPEA. These services are key
15 and critical to the continued success of the technical solution and architecture
16 design in which they are based upon.

17 This investment covers implementation support for hardware and environment
18 upgrades, security vulnerability remediation, and the adoption of both major and
19 minor software releases. Also included in this effort is the support for the user base
20 as they respond to new business needs, continuous improvements, and process
21 changes to improve their productivity.

22 See Exhibit A-24 N3 Line 64 for additional project details.

23

24 **Customer Digital Channels and Self-Service Program**

- 25 • The Company will invest \$7.8 million in the **Customer Digital Channels and Self-**
26 **Service Program** project over the course of 36-months ending December 31, 2025

Line
No.

1 and has a historical spend of \$1.6 million in 2022, as shown on line 6 of Exhibit A-
2 12 Schedule B5.7.2.

3 Significant portions of the DTE Web and mobile digital customer transactions
4 continue to run on legacy platforms. The customer mobile applications run on
5 frameworks and foundational code that was written in 2013-2014. Substantial
6 portions of the customer web experience run on IBM WebSphere Portal (version
7 8), which IBM no longer supports. The Company is investing in a 5-year
8 transformational agenda to move off these aging platforms, however continued
9 investments are needed to maintain and make improvements to the existing assets,
10 until such time as they can be retired. This Customer Digital Channels and Self-
11 Service Program is comprised of capital business cases that will deliver ongoing
12 enhancements to the Web and Mobile App that allow the Company to maintain key
13 customer transactions and improvement in digital self-service metrics (e.g., Web
14 Digital Engagement Rate (DER), Web Completion Rates), while the transformation
15 efforts are in progress.

16 See Exhibit A-24 N3 Line 68 for additional project details.

17

18 **Customer Information Technology (CIT) Configuration Management**

- 19 • The Company will invest \$3.6 million in the **Customer Information Technology**
20 **(CIT) Configuration Management** project over the course of 36-months ending
21 December 31, 2025, and has a historical spend of \$0.5 million in 2022, as shown
22 on line 7 of Exhibit A-12 Schedule B5.7.2.

23 This project provides streamlined configuration, release, compliance and audit
24 management processes for the Customer and Business Planning and Development
25 (BPD) portfolio of assets. It assists the operational team in configuring, building,
26 and deploying planned functional release for all assets of the portfolio.

Line
No.

1 Configuration, build, and deployment support is in alignment with the needs of the
2 application teams, the business partners, and customers.

3 See Exhibit A-24 N3 Line 72 for additional project details.

4

5 **Customer Legacy Application Health**

6 • The Company will invest \$1.6 million in the **Customer Legacy Application**
7 **Health** project over the course of 36-months ending December 31, 2025, as shown
8 on line 8 of Exhibit A-12 Schedule B5.7.2.

9 The Company reflects a variance of \$0.2 million more in the 36 months ending
10 December 31, 2024, than was approved for cost recovery in U-21297. This is
11 primarily due to additional spend in 2023 as explained below.

12 In 2023, previously unsupported applications were incorporated into the revised
13 support agreement with the strategic vendor partner. Incorporation of these
14 applications was needed to ensure their resiliency and availability to customers; and
15 2) The sourcing strategy also increased the depth of application support coverage
16 within the Customer IT portfolio. The additional resources will also increase the
17 availability and resiliency of applications.

18 Systems that are not core billing systems or self-service channels are called Legacy
19 applications. These applications include Agency Web Site (AGW), Interactive
20 Voice Recognition (IVR), old billing systems in read-only mode (CSB, KCS) and
21 the Enterprise Service Bus (ESB) and are some of the important systems that fall
22 in this category.

23 AGW is the agency website application that our partners like Salvation Army and
24 others use to help our low-income customers. The IVR is a recognition system key
25 to our customers calling Contact Center. Per compliance, the Company is
26 maintaining legacy billing systems, CSB/KCS (Residential and Commercial), in

Line
No.

1 read-only mode for inquiries. ESB is middleware software that communicates
2 between the core billing system (CR&B) and the channels (Web, Mobile, IVR and
3 Kiosk). It is critical that these system function for customers to complete their
4 transactions. Hence, these customer systems require regular production releases to
5 support daily operations and the effective delivery of service to our customers. This
6 includes vulnerability management and deployments of required capabilities or
7 functionality.

8 The 2022-2024 spend was approved for cost recovery in U-21297. See Exhibit A-
9 24 N3 Line 76 for additional project details.

10

11 **Customer Relationship and Billing Program**

- 12 • The Company will invest \$4.2 million in the **Customer Relationship and Billing**
13 **Program** project over the course of 36-months ending December 31, 2025, and has
14 a historical spend of \$0.4 million in 2022, as shown on line 9 of Exhibit A-12
15 Schedule B5.7.2.

16 The CR&B Platform is a fully implemented system. The CR&B production
17 environment needs to be regularly maintained to ensure the health, compliance, and
18 strategic alignment of the SAP CR&B Platform while providing a high level of
19 availability with accurate data to meet the business needs of the Customer Service,
20 Billing and Metering, Distribution Operations, Energy Optimization, Treasury,
21 Controller, Gas Operations, and Electric and Gas Sales and Marketing
22 organizations. These are all part of our ongoing customer excellence efforts.

23 The 2023 through 2025 scope of this investment will support achieving sustained
24 and improved performance of CR&B Platform while furthering strategic alignment
25 with the platform vendors (e.g., SAP, OpenText). Included in this effort is the

Line
No.

1 strategic oversight for the CR&B Platform including the development and delivery
2 of the Technology Platform Plan.

3 The 2022-2024 spend was approved for cost recovery in U-21297. See Exhibit A-
4 24 N3 Line 80 for additional project details.

5

6 **Hybris Application Health**

7 • The Company will invest \$3.9 million in the **Hybris Application Health** project
8 over the course of 36-months ending December 31, 2025, with a historical spend
9 of \$2.0 million in 2022 as shown on line 10 of Exhibit A-12 Schedule B5.7.2.

10 Hybris Software Solution, an e-commerce delivery platform that will allow the
11 Company to design and deliver non-metered products⁷ (e.g., Surge Protection
12 Program, TreeGuard Assurance, Smart Savers, and Smart Currents) in conjunction
13 with existing metered offerings. These systems require regular production
14 deployments to support daily operations and the effective delivery of service to our
15 customers. There are 12 monthly scheduled releases annually to accommodate
16 deployments.

17 The current version of Hybris platform is 2005 with an end-of-life date by the
18 providing vendor of March 2023. In 2023, this project completed the upgrade to
19 the supported version 2211 of SAP Commerce Cloud and SAP Marketing Cloud.

20 The Company reflects a variance of \$3.2 million more in the 36 months ending
21 December 31, 2024, than was approved for cost recovery in U-21297. This is
22 primarily due to the project adding scope to upgrade the Sales and Service platform
23 and created the required interface between Cloud Platform and DocuSign and
24 OpenText, in 2022. The configuration, testing and deployment of the upgrades and

⁷ Non-metered products are products that do not require a meter for billing purposes

Line
No.

1 interfaces was delivered over 6 months. In 2023, we had to perform 3 upgrades to
2 the SAP Commerce Platform to bring the platform to be compliant with SAP
3 recommendation. Also, for the regulatory requirement of rate change, we updated
4 the commerce platform configuration and content for renewable energy programs.
5 During the 2023 storms, SAP Marketing Cloud platform faced significant
6 performance issues resulting in a redesign of the architecture to consolidate
7 notification workflows so that the platform can send notifications to the customers
8 on time. The 2022-2024 spend was approved for cost recovery in U-21297.
9 See Exhibit A-24 N3 Line 84 for additional project details.

10

11 **MIGreenPower Program Stabilization**

12 • The Company will invest \$4.7 million in the MIGreenPower Program Stabilization
13 project over the course of 36-months ending December 31, 2025, and has a
14 historical spend of \$0.4 million in 2022, as shown on line 11 of Exhibit A-12
15 Schedule B5.7.2.

16 The Company reflects a variance of \$1.1 million more in the 36 months ending
17 December 31, 2024, than was approved for cost recovery in U-21297. This is
18 primarily due to a scope addition of backlog enhancements to include Commerce
19 cloud, Marketing and Analytics cloud components to the scope of the project
20 resulting in an updated forecast for 2024. This allowed for the line items and credits
21 to be appropriately reflected on Customer Renewable Energy bill.

22 The intent of this project is to sustain and support the MIGreenPower applications
23 in production by modifying application configuration as projects are completed as
24 necessary to maintain a stable platform, completing minor enhancement request to
25 support business process changes and required application updates. The 2022-2024
26 spend was approved for cost recovery in U-21297.

Line
No.

1 See Exhibit A-24 N3 Line 88 for additional project details.

2

3 **Powerley Customer Platform Application Health**

- 4 • The Company will invest \$7.2 million in the **Powerley Customer Platform**
5 **Application Health** project over the course of 36-months ending December 31,
6 2025, as shown on line 12 of Exhibit A-12 Schedule B5.7.2.

7 Powerley has developed and supports several systems used by DTE's external
8 customers (e.g. DTE Insight, Energy Bridges, Bill Management). These systems
9 need to be maintained and upgraded to support new mobile operating systems
10 otherwise DTE's external customers will lose the capabilities they are paying for.
11 DTE does not maintain the internal expertise or staffing levels to support Powerley
12 Cloud systems and needs to provide the required support services to maintain the
13 solutions provided by Powerley. Also enhancing the Bill Management web site to
14 include various new features to assist customers to understand their usage, rates,
15 their current and forecasted bill / usages.

16 Powerley provides services including all necessary architecture components and
17 cloud computing services (i.e. Amazon Web Services) that are utilized to maintain
18 the user-facing functionality as expected for:

- 19 • DTE Insight iOS and Android Mobile application, with ongoing software
20 updates as required by respective operating systems
- 21 • Energy Bridges, including ongoing firmware support for real-time usage
22 data from AMI meters and Zigbee and Z-Wave connected devices
- 23 • Bill Management (billmgmt.dteenergy.com) enhancements, with ongoing
24 software updates and resolve defects(O&M) and provide updates as required
- 25 • Powerley Portal (portal.pwly.io), with support for all currently provided
26 functionality, including customer management, energy usage visualization, bill

Line
No.

1 impact information, content management, budget/rate calculator support, and all
2 Demand Response capabilities.

3 See Exhibit A-24 N3 Lines 89-91 for additional project details.

4

5 **Service Cloud Product Support for Customer Document Submission**

6 • The Company will invest \$0.8 million in the **Service Cloud Product Support for**
7 **Customer Document Submission** project over the course of 36-months ending
8 December 31, 2025, as shown on line 13 of Exhibit A-12 Schedule B5.7.2.

9 This project was previously approved in U-21297 and reflects a variance of \$0.2
10 million more in the 36 months ending December 31, 2024, than was approved for
11 cost recovery due to the 20% disallowance from the Commission.

12 The Customer Service Organization is seeking a long-term solution for external
13 customers to submit documents for review and approval by DTE businesses during
14 various customer service scenarios where document verification is required (i.e.,
15 Contact Center, Revenue Management and Protection (RM&P) and Collection
16 Exceptions). The document submission portal is the only secure way for the
17 Customer Service organization to obtain documents from DTE customers. When
18 the document submission process is broken, it has an operational impact on
19 customers trying to complete MIMO transactions, enrollment into payment
20 programs such as low-income, obtain medical holds, etc.

21 See Exhibit A-24 N3 Line 92 for additional project details.

22

23 **Supporting Capabilities Test data and Test Data Mgmt.**

24 • The Company will invest \$1.0 million in the **Supporting Capabilities Test Data**
25 **and Test Data Mgmt** project over the course of 36-months ending December 31,
26 2025, as shown on line 14 of Exhibit A-12 Schedule B5.7.2.

Line
No.

1 This project was previously classified as an IT Enhancement in U-21297 and
2 supported by Company Witness Hatsios (U-21297 Capital Exhibit A-12 Schedule
3 B5.7.3 (Hatsios), Line 22).

4 Currently the CR&B application team has a process to generate any type of test
5 data to help self-service channels, Assisted Channel, and Training with their
6 Sustainment and project testing activities. The team also needs to coordinate
7 regression and performance test with the vendors. Vendors maintain the regression
8 scripts and ensure the scripts are run every month to ensure there are no issues
9 identified before production launch. In the instance where the solution is customer
10 facing, the vendor ensures the customer facing website and its corresponding
11 backend can handle the load under certain significant events like Outage, Move in
12 Move out, etc.

13 See Exhibit A-24 N3 Lines 93-94 for additional project details.

14

15 Return-to-Health

16 **Q37. Can you explain in detail Customer Service investments in the ‘Return-to-**
17 **Health’ category?**

18 A37. The Company will invest \$25.6 million in the Return-to-Health category over the
19 course of 36-months ending December 31, 2025, as shown in lines 15 through 24
20 of the Capital Expenditures Exhibit A-12 Schedule B5.7.2. The planned costs are
21 primarily across projects that are as discussed further below:

22

23 **Agency Web Site AGW Rebuild**

24 • The Company will invest \$1.8 million in the **Agency Web Site AGW Rebuild**
25 project over the course of 12-months ending December 31, 2023, and has a
26 historical spend of \$2.7 million in 2022 as shown on line 15 of Exhibit A-12 B5.7.2.

Line
No.

1 The Agency Website (AGW) was designed in 2004 to support the online interface
2 between human service agencies and DTE. The need to rebuild is the result of
3 requirement changes due to State and Federal guidelines year over year and
4 introduction of new programs and new technology availability. The new system
5 will allow external agencies the ability to track special program enrollments and
6 review data related to bill payment assistance for customers-based program
7 provided funding.

8 This project was previously approved for cost recovery in U-21297, and the
9 Company reflects a variance of \$1.6 million more in the 36 months ending
10 December 31, 2024. This is primarily due to additional scope in 2023 to handle
11 Customer Payments, Payment refund, Chargebacks on a nightly basis. The scope
12 also includes to validate customer collection status, disconnect status before
13 handling any payments. The 2022 spend was approved for cost recovery in U-
14 21297.

15 See Exhibit A-24 N3 Line 96 for additional project details.

16

17 **Archive and Purge**

- 18 • The Company had a historical spend of \$1.5 million in the **Archive and Purge**
19 project over the 24 months ending December 31, 2023, as shown on line 16 of
20 Exhibit A-12 Schedule B5.7.2.

21 Data archiving and purging refers to the saving of customer transactional data (e.g.,
22 invoices, meter reads) and correspondence data (e.g., emails, letters) and makes the
23 data available for retrieval for a specified period, after which it will be purged from
24 the CR&B system.

25 With the implementation of the Company's C360 billing system, the current SAP
26 CR&B platform was sized to retain three years of transactional data and 13 months

Line
No.

1 of customer correspondence. Retention policies for customer correspondence have
2 been internally reviewed and require the Company to produce such documentation
3 for customers for up to seven years. Retaining this level of historical data within
4 the transactional system will degrade performance and overrun the system design
5 size.

6 The Company reflects a variance of \$0.4 million more in the 36 months ending
7 December 31, 2024, than was approved for cost recovery in U-21297. During the
8 design phase for data storage, it was determined that the optimal solution would be
9 to build upon cloud data storage rather than on premise data storage to remediate /
10 eliminate dependency to CR&B. This would further reduce data volume
11 management challenges in CR&B. This required outside vendor services to support
12 the implementation which resulted in the increased spend.

13 See Exhibit A-24 N3 Lines 97-98 for additional project details.

14

15 **Contact Center Infrastructure**

- 16 • The Company will invest \$0.7 million in the **Contact Center Infrastructure**
17 project over the course of 12-months ending December 31, 2023, with a historical
18 spend of \$1.8 million in 2022 as shown on line 17 of Exhibit A-12 B5.7.2.

19 Contact Center infrastructure includes all the hardware and software that enables
20 the Contact Center's telephony and IVR systems to operate. The infrastructure
21 includes a combination of servers (both physical and virtual), databases,
22 applications, and vendor appliances. The current telephony systems were initially
23 installed in 2017 while the current IVR systems were put into service between
24 2018-2019.

25 This work is critical to remain within vendor supported versions to receive future
26 support as new vulnerabilities arise. In addition, investing in upgrades to this core

Line
No.

1 infrastructure will provide the required foundation for future projects such as the
2 Migrate IVR to the cloud project.

3 See Exhibit A-24 N3 Lines 99-100 for additional project details.

4

5 **Customer Bill Print and Archive Software**

6 • The Company invested \$0.7 million in 2022 in the **Customer Bill Print and**
7 **Archive Software** project in the historical period, which was not included in U-
8 21297, as shown on line 18 of Exhibit A-12 Schedule B5.7.2.

9 DTE Electric and DTE Gas used two OpenText products – StreamServe and
10 Extended Enterprise Content Management (xECM). This project upgraded
11 StreamServe which the vendor had deemed end-of-life and no longer providing
12 support as of March 2020. These products support the Customer Bill Print and
13 Archive business processes. Stream Serve is used to convert the raw data files from
14 the SAP Customer Relationship and Billing (SAP CR&B) system and converts
15 them into customer bills and correspondences. DTE sends approximately 156 types
16 of correspondence to customers ranging from outage alerts, payment plan changes,
17 Choice enrollment notifications, bankruptcy deposit requests, home heating tax
18 credit, letter of credit, etc. Every day, approximately 150,000 bills and 20,000
19 correspondences are sent and running operations which directly affects our
20 customers and DTE on an unsupported platform was unacceptable. Extended
21 xECM stores and archives transactional data and correspondences by customers for
22 retrieval in the digital channels by the Customer Representatives (CRs) in the
23 Customer Relationship Manager application. CRM is a Customer Relationship
24 Management application, a front-end SAP tool used by CRs to support customer
25 requests.

26 See Exhibit A-24 N3 Line 101 for additional project details.

Line
No.

1

2 **Customer Experience Suite**

- 3 • The Company will invest \$0.5 million in the **Customer Experience Suite** project
4 over the course of 12-months ending December 31, 2023, and has a historical spend
5 of \$2.6 million in 2022, as shown on line 19 of Exhibit A-12 Schedule B5.7.2.

6 In 2022, the Company implemented the Adobe Experience Cloud product. This
7 scope included architecture design, creation of content templates, population of
8 digital assets, data layer creation for analytics, and migration of approximately 400
9 static content pages from our legacy IBM Web Content Management platform to
10 the new Adobe platform.

11 This project was approved for cost recovery in U-21297, and the Company is
12 seeking recovery of the \$0.6 million more spend projected in the 36 months ending
13 December 31, 2024, for reasons described below.

14 The spend in 2023 was not planned and reflects an extension of the schedule and
15 the labor cost to remediate vulnerabilities identified during system testing, prior to
16 production release resulting in the incremental spend.

17 See Exhibit A-24 N3 Lines 102-103 for additional project details.

18

19 **Customer Service Infrastructure Landscape & Growth**

- 20 • The Company will invest \$5.9 million in the **Customer Service Infrastructure**
21 **Landscape & Growth** project over the course of 12-months ending December 31,
22 2023, as shown on line 20 of Exhibit A-12 Schedule B5.7.2.

23 The Company reflects a variance of \$2.1 million more in the 36 months ending
24 December 31, 2024, than was approved for cost recovery in U-21297. This is
25 primarily due to an increase in hardware cost and the increase in labor cost to
26 resolve pre-production deployment issues.

Line
No.

1 Currently, DTE uses the SAP CR&B platform to provide customer relationship
2 management, customer billing, customer master data management, business data
3 management and application process orchestration. These functions are performed
4 by the SAP CR&B applications Customer Relationship Manager (CRM), Industry
5 Solutions Utility (IS-U), Business Warehouse (BW) and Process Orchestrator (PO).
6 These applications and the associated databases are hosted on DTE premises on
7 physical hardware and infrastructure. The current physical hardware and
8 infrastructure was purchased and installed prior to SAP CR&B go-live in 2017. All
9 hardware and infrastructure for the CR&B platform will reach end-of-life (EOL) at
10 the end of 2022. This project refreshed the entire CR&B platform with hardware
11 and infrastructure that is appropriately sized and supported for an additional five
12 years.

13 See Exhibit A-24 N3 Line 104 for additional project details.

14

15 **Digital Channels Transformation Program**

- 16 • The Company will invest \$10.5 million in the **Digital Channels Transformation**
17 **Program** over the course of 36-months ending December 31, 2025, with a
18 historical spend of \$0.5 million in 2022, as shown on line 21 in Exhibit A-12
19 Schedule B5.7.2.

20 While the Company has made measurable improvements in providing customers
21 with the ability to interact with DTE on the digital Web and Mobile customer
22 channels for the five key customer transactions (MIMO, Outage, Collection, Billing
23 and Payment). These digital platforms are aging, run on fragmented technologies,
24 and, in some cases, unsupported. The core DTE website runs on a platform (IBM
25 WebSphere Portal) that is unsupported, and no longer owned by the original
26 supplier (IBM). This presents an operational risk to the channel and could lead to

Line
No.

1 the inability to serve DTE customers through the Web. The DTE iOS and Android
2 Mobile applications have benefited from functional enhancements, however the
3 foundational codebases for both applications were written in 2013-2014. Apple and
4 Google continuously enhance and improve mobile phone application platforms,
5 releasing new major versions annually. The aging DTE mobile codebase makes
6 releasing new features and functionality to customers complex and in some cases
7 not possible. During storms in 2021-2022, customers regularly experienced
8 reliability issues with the mobile applications due to aging code, leading to
9 difficulties reporting problems with service and receiving restoration updates.

10 While the Company has made measurable investments to improve the digital web
11 and mobile customer channels and begin moving to the cloud, digital platforms are
12 aging, run on fragmented technologies, and in some cases, unsupported technology
13 platforms. The core DTE website runs on a platform (IBM WebSphere and IBM
14 WebSphere Portal) that is unsupported, and no longer owned by the original
15 supplier (IBM). This is an operational risk to channel and could, leading to
16 inability to serve DTE customers on web channel. Additionally, architecture is
17 consistently one-off, caused by app code duplication that can be resolved by
18 building a standardized shell to eliminate waste/redundancy in excessive
19 application code.

20 In 2025 this project will modify the separate and distinct Payments and Outage
21 single-page applications to become web components that can reside within the
22 architecture that will be established in 2023-2024.

23 The project will design, build, and test the current functionality of Guest Pay,
24 Manage Payment Methods, Authenticated Payments page to the newer architecture
25 hosted in the new platform. The project will also design, build, and test the current

Line
No.

1 functionality of Report Outage, Down Wire, Get Status, Report outage by Police
2 and Fire, Street Lighting to the newer architecture hosted in the new platform.
3 Alternatives considered included utilizing off the shelf solutions and continuing
4 with the current approach of building multiple single page applications and was
5 rejected because if we need to utilize off the shelf solutions, it will require to build
6 a common foundational architecture and build the interfaces to integrate with the
7 backend.
8 A do nothing alternative was rejected because without a common foundational
9 architecture, product teams will continue to build separate single page applications
10 for each transaction, driving up costs and increasing customer friction. The 2022-
11 2024 spend was approved for cost recovery in U-21297.
12 See Exhibit A-24 N3 Lines 108 for additional project details.

13

14 **Plant & Field**

15 **Q38. What is included in the Plant & Field Portfolio?**

16 A38. The Plant & Field Portfolio supports IT business systems used by organizations
17 such as Distribution Operations (DO), Energy Supply (ENS), Generation
18 Optimization (GenOpts), and Fermi. Business systems in this area include core
19 organization-spanning technologies such as the Work and Asset Management
20 system, as well as department-focused systems such as Outage Management,
21 equipment Tagging⁸, Mapping, and other similar technologies.

22

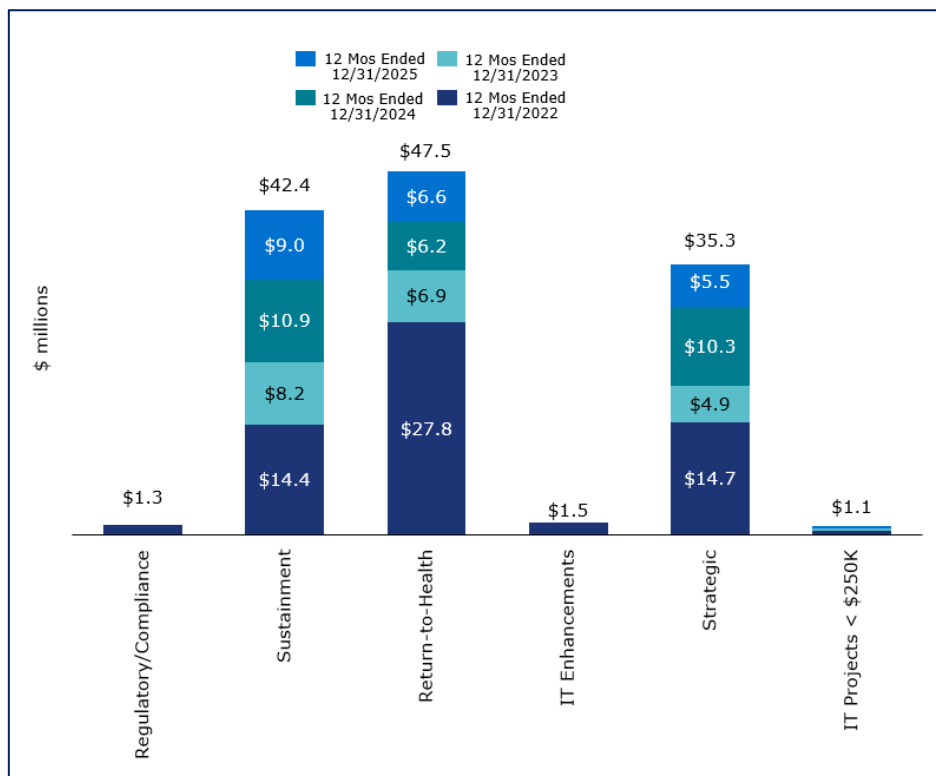
23 **Q39. What are the projected costs for investments in the Plant & Field Portfolio?**

⁸ for maintenance and authorized use

Line
No.

1 A39. As reflected on Line 5 of Exhibit A-12 Schedule B5.7, page 1, capital costs for
2 Plant & Field total \$58.9 million for the historical test year ended December 31,
3 2022, \$47.7 million in the bridge period (for the 24 months ending December 31,
4 2024), and \$22.6 million for the projected test period ending December 31, 2025.
5 The individual initiatives that fall into this area appear in Exhibit A-12 Schedule
6 B5.7.4. The synopses below provide the total spend for each line item involved in
7 the Company's request for recovery in this rate case. with details regarding
8 breakout by historical period, projected bridge period, and projected test period laid
9 out in Exhibit A-12 Schedule B5.7.4, in columns d, g and h, respectively. Figure
10 10 represents a high-level view of capital allocation within the portfolio.

Figure 10 Plant & Field – IT Investment



Line
No.

1 Regulatory/Compliance

2 **GenOpts-FERC Order 841 Compliance**

3 **Q40. Can you explain in detail the Plant and Field investment in the Regulatory**
4 **Compliance category?**

5 A40. Yes, the Company will invest \$1.3 million in the **GenOpts-FERC Order 841**
6 **Compliance** Project over the course of 12-months ending December 31, 2025, as
7 shown on line 1 of Exhibit A-12 Schedule B5.7.4.
8 Federal Energy Regulatory Commission (FERC) Order 841 sets out electric storage
9 resource regulations as well as the broader participation model associated with all
10 involved entities. The Company's investment is both to comply with FERC Order
11 841⁹ and to enable Electric Storage Resources (ESR) interconnected to the DTE
12 Distribution System to participate in the Wholesale Power Market. This will
13 provide functionality allowing any DTE Electric customer to install an ESR and
14 start directly transacting wholesale power with the Midcontinent Independent
15 System Operator (MISO)¹⁰. To accomplish these goals, DTE must (1) make
16 appropriate adjustments to meter configuration to exclude wholesale power from
17 billing calculations and (2) establish a wholesale distribution customer rate to
18 compensate for distribution services provided to wholesale market participants.
19 The Company reflects a variance of \$1.1 million less in the 36 months ending
20 December 31, 2024, than was approved for cost recovery in U-21297. This project
21 was rescheduled to 2025, and there is no change to planned scope or cost.
22 See Exhibit A-24 N3 Line 114 for additional project details.

23

⁹ Order No. 841 [Order No. 841 | Federal Energy Regulatory Commission \(ferc.gov\)](https://www.ferc.gov/orders/841) accessed 01/04/23

¹⁰ MISO is an independent, not-for-profit, member-based organization focused on (1) Managing the generation and transmission of high-voltage electricity across 15 U.S. states and the Canadian province of Manitoba, (2) Managing the energy markets in the MISO region, and (3) Planning the grid of tomorrow

Line
No.

1 Sustainment

2 **Q41. Can you explain in detail Plant & Field investment in the Sustainment**
3 **category?**

4 A41. The Company will invest \$28.1 million in the Sustainment category over the course
5 of 36-months ending December 31, 2025, as shown in lines 2 through 16 of the
6 Capital Expenditures Exhibit A-12 Schedule B5.7.4. The planned costs are
7 primarily across projects that are discussed further below:

8

9 **Advance Metering Infrastructure Application Health**

- 10 • The Company will invest \$5.0 million in the Advance Metering Infrastructure
11 Application Health project over the course of 36 months ending December 31,
12 2025, and has a historical spend of \$0.8 million in 2022, as shown on line 2 of
13 Exhibit A-12 Schedule B5.7.4.

14 Currently, Advanced Metering Infrastructure (AMI) has 2.5 million electric and 1.3
15 million gas meters. The electric AMI meters are integral to Distribution Operations
16 (DO) storm management, interruptible service/demand response, electric power
17 quality, long-term load planning, and customer billing accuracy. Planned
18 investment in this area will address the servers and related Oracle databases that are
19 either currently end-of-life or as scheduled to be end-of-life per the Original
20 Equipment Manufacturers, referred to as OEM. The core AMI systems require
21 ongoing operational asset health upgrades to maintain the overall reliability and
22 availability of the infrastructure hosting the application and data. This investment
23 also will provide further code development and AMI Portal configurations which
24 will enable the required functionality within the AMI system for reporting on
25 interval reads, tracking disconnects and reconnects, enable automatic failover

Line
No.

1 between data centers to allow for full redundancy and other data management
2 functions.

3 The Company reflects a variance of \$0.8 million more in the 36 months ending
4 December 31, 2024, than was approved for cost recovery in U-21297. This is
5 primarily due to the 20% disallowance from the commission, which resulted in a
6 shift in project timing. The underspend from 2023 represents capital work shifted
7 into 2024. The 2024 overspend is this additional capital work plus the funds needed
8 to successfully execute the restructured scope.

9 The 2022-2024 spend was approved for cost recovery in U-21297. See Exhibit A-
10 24 N3 Line 118 for additional project details.

11

12 **ClickSoft Application Health**

13 • The Company will invest \$1.1 million in the **ClickSoft Application Health** project
14 over the course of 36-months ending December 31, 2025, as shown on line 3 of
15 Exhibit A-12 Schedule B5.7.4. The project has a historical spend of \$0.002 million
16 in 2022.

17 ClickSoft provides increased visibility of crews by dispatchers, availability of real
18 time status at the point of activity to customers, and increased visibility into
19 business and crew requests for improvements. This project manages the ClickSoft
20 application health and associated infrastructure through triaging, tracking,
21 resolution of issues, and prioritizing business requests for improvements &
22 upgrades.

23 The 2022-2024 spend was approved for cost recovery in U-21297. See Exhibit A-
24 24 N3 Lines 119-122 for additional project details.

25

Line
No.

1 **Distribution Operations Application Health**

2 • The Company will invest \$3.5 million in the **Distribution Operations Application**
3 **Health** project over the course of 36-months ending December 31, 2025, and has a
4 historical spend of \$1.8 million in 2022, as shown on line 4 of Exhibit A-12
5 Schedule B5.7.4

6 This project covers 50 IT supported applications impacting field crew
7 assignment/management, central dispatch communication systems in support of
8 field workers, grid management/distribution engineering, tree trim vegetation
9 management, and public protection for storm additions. These applications are key
10 operational assets fundamental to our primary business functions – making the
11 ongoing required support a non-discretionary investment.

12 The 2022-2024 spend was approved for cost recovery in U-21297. See Exhibit A-
13 24 N3 Line 126 for additional project details.

14

15 **DTE Electric Generation Capacity Application Health**

16 • The Company will invest \$1.7 million in the **DTE Electric Generation Capacity**
17 **Application Health** project over the course of 36-months ending December 31,
18 2025, and has a historical spend of \$0.7 million in 2022, as shown on line 5 of
19 Exhibit A-12 Schedule B5.7.4.

20 This project was previously approved in U-21297 and reflects a variance of \$0.4
21 million more in the 36 months ending December 31, 2024, than was approved for
22 cost recovery due to the 20% disallowance from the Commission.

23 For the duration of 2023-2025, there will be an annual project spend to fund
24 regularly scheduled releases to our Generation Supply Management System
25 (GSMS) platform, which the Company uses to effectively calculate which
26 generation plants it will offer into the MISO market, which in turn contributes to

Line
No.

1 the selection of plant capacity running per the MISO market schedule. Specifically,
2 the GSMS vendor targets a quarterly release schedule, which the Company must
3 adopt to remain compliant with MISO regulations such as the determination of how
4 a plant is offered to the market and the need to remain current with MISO Shadow
5 Billing (the method used to settle charges and revenue with the Company). When
6 the Company is not current with the application release schedule, the Company
7 loses its ability to understand and prepare accordingly for our financial exposure in
8 this market as our calculations would not match current MISO calculation rules.

9 In addition, there will be the required investment associated with the changes MISO
10 is making to its back-end system. These changes will jeopardize the way the
11 Company's GSMS system connects to, and interacts with, MISO's system.

12 The 2022-2024 spend was approved for cost recovery in U-21297. See Exhibit A-
13 24 N3 Line 130 for additional project details.

14

15 **DTE Electric Utility Network (UN)**

- 16 • The Company will invest \$0.7 million in the **DTE Electric Utility Network (UN)**
17 project over the course of 36-months ending December 31, 2025, as shown on line
18 6 of Exhibit A-12 Schedule B5.7.4.

19 This project was previously approved in U-21297 and the Company reflects a
20 variance of \$0.1 million more in the 36 months ending December 31, 2024, than
21 was approved for cost recovery due to the 50% disallowance from the Commission.

22 DTE currently uses the ESRI ArcMap platform GIS (Geographic Information
23 System) for geospatial data and analysis. This data includes information such as the
24 distribution of electrical assets. ArcMap, however, will no longer be supported by
25 Q1 2025. To account for this adjustment and maintain our current-state
26 capabilities, the DTE Electric Utility Network project will implement the new ESRI

Line
No.

1 UN product in the cloud. This product replacement will increase availability,
2 recoverability, scalability, and security while enabling business process efficiency.
3 The initiative will leverage the latest technology on location data, business
4 intelligence, and integrated systems to drive enterprise system automation and
5 business performance for our public-facing and internal IT systems. It will improve
6 safety in the field, improve reliability metrics and outage information, reduce
7 customer complaints, and improve overall customer satisfaction.
8 See Exhibit A-24 N3 Lines 131 -132 for additional project details.

9

10 **ESRI Application Health**

11 • The Company will invest \$0.9 million in the **ESRI Application Health** project
12 over the course of 36-months ending December 31, 2025, as shown on line 7 of
13 Exhibit A-12 Schedule B5.7.4.

14 This project was previously approved in U-21297 and the Company reflects a
15 variance of \$0.1 million more in the 36 months ending December 31, 2024, than
16 was approved for cost recovery due to the 20% disallowance.

17 ESRI application health supports enhancements to the Company's automated
18 mapping system (Geographic Information System or GIS) that supports all GPS
19 mapping data including operating maps and customer-facing outage maps. This
20 investment includes procuring additional user licenses, IT labor cost associated
21 with testing/installing service packs and security vulnerability remediation as part
22 of regularly scheduled release enhancements. Failure to deploy GPS releases
23 would result in inaccurate mapping data. Additionally, the investment is required
24 to improve the management and sharing of data via workflow automation.

25 See Exhibit A-24 N3 Lines 133-134 for additional project details.

26

Line
No.

1 **Fuel Supply Application Health**

- 2 • The Company will invest \$1.3 million in the **Fuel Supply Application Health**
3 project over the course of 36-months ending December 31, 2025, and has a
4 historical spend of \$0.4 million in 2022, as shown on line 8 of Exhibit A-12
5 Schedule B5.7.4.

6 This project will deliver the non-discretionary scope to manage key applications
7 used by Fuel Supply. These applications are as follows:

8 AAR: Automated Rail Receipt is a solution used by Corporate Fuel Supply to
9 manage inputs of coal, petcoke, and oil used by DTE's generation fleet. This
10 • system interfaces with data hosted by the vendor application Envision, which
11 provides the location data of coal rail cars used by Corporate Fuel Supply.

12 • GenMart: This data repository holds information related to the generation fleet
13 and is utilized by Generation Optimization (GenOpts) and Corporate Fuel
14 Supply (CFS). Fuel Inventory and Consumption reports for CFS allow DTE to
15 build cost models and run cost-based scenarios for the purpose of market
16 management, logistics decision making, and rail fleet optimization. It enables
17 optimization and the ability to combine delivered fuel cost, plant variable cost,
18 and dispatch cost to develop an optimized generation solution. This repository
19 includes rail car maintenance analytics, aggregated data used by GenOpts for
20 analytics on load components, information on Net System Output, and MISO
21 Residual Load Adjustment data. Additionally, it serves as an archive database
22 for all generation and load meters as well as emissions data.

23 Beginning in 2021, the Power Cost Inc. Energy Trading and Risk Management
24 (ETRM) application was implemented, delivering functions to plan natural gas
25 purchasing, transportation, inventory management, nominating, and scheduling for
26 the DTE gas fueled generation units. Starting in 2022, quarterly vendor releases to

Line
No.

1 ETRM and AAR systems were tested and deployed. These upgrades are required
2 to remain current under vendor support and provide new product capabilities to end
3 users who were included in upgrades.

4 The 2022-2024 spend was approved for cost recovery in U-21297. See Exhibit A-
5 24 N3 Lines 135-138 for additional project details.

6

7 **ITS-SRS Application Health**

8 • The Company will invest \$1.6 million in the **ITS-SRS Application Health** project
9 over the course of 36-months ending December 31, 2025, as shown on line 9 of
10 Exhibit A-12 Schedule B5.7.4.

11 The ITS-SRS staff supports the ADMS, GMS and eSCADA application portfolios.
12 The requirements of supporting critical systems that ensure the safe and reliable
13 operation of the electrical grid demand a high level of support. This demand covers
14 the resource costs to support the ongoing operation of these applications. To ensure
15 high availability and optimal performance, the system requires annual capital
16 investment for regular upgrades and enhancements to the software products,
17 servers, infrastructure, and workstations as well as accompanying expense for
18 patching, compliance efforts, and maintenance to ensure that these systems are
19 running at their best and can handle the demands placed on them.

20 See Exhibit A-24 N3 Lines 139-140 for additional project details.

21

22 **ITS ADMS Application Health**

23 • The Company will invest \$2.1 million in the **ITS-ADMS Application Health**
24 project over the course of 36-months ending December 31, 2025, as shown on line
25 10 of Exhibit A-12 Schedule B5.7.4.

Line
No.

1 The ITS ADMS Application Health Program covers a suite of applications in use
2 at DTE for safe and effective operation in the Electric System Operations Center
3 (ESOC) and for Distribution Operations Dispatch. These include the following:

- 4 • OMS (Outage Management System) is used to manage and respond to
5 outages in the power grid.
- 6 • DMS (Distribution Management System) is used to manage the distribution
7 of power on the grid.
- 8 • EMS (Energy Management System) is used to monitor and control the
9 generation and transmission of power.
- 10 • GMS (Generation Management System) is used to manage the generation
11 of power, typically at a power plant or other large facility.
- 12 • SOM (System Operations Management) is used to manage the overall
13 operation of the power grid.

14 The ADMS application portfolio is critical in safely supporting the electrical grid
15 through use of these systems, which each require their own level of enhancements,
16 upgrades, and support as well as licensing. The ADMS team is responsible for
17 supporting and updating these applications as well as for integration infrastructure
18 (ESB or Enterprise Service Bus) that connects all aspects of ADMS to DTE legacy
19 systems. Without the proper enhancements, upgrades, and maintenance, there is a
20 risk of system failure or malfunction, which can have serious consequences on the
21 safe and reliable operation of the electrical grid.

22 See Exhibit A-24 N3 Lines 141-142 for additional project details.

23

24 **Nuclear Generation Business Systems Replacement**

- 25 • The Company will invest \$2.0 million in the **Nuclear Generation Business**
26 **Systems Replacement** project over the course of 36-months ending December 31,

Line
No.

1 2025, and has a historical spend of \$0.5 million in 2022, as shown on line 12 of
2 Exhibit A-12 Schedule B5.7.4.

3 Nuclear Generation has 36 key and critical applications that exist to satisfy
4 regulatory, safety or business process requirements. The business unit has
5 historically had between 3 and 6 critical and key applications that need to be
6 updated each year. These include software, hardware and/or database environment
7 upgrades or replacement each year due to regulatory changes, obsolescence,
8 security vulnerabilities and continued protection from the risk of system failure and
9 possible cyber-attack. Nuclear Generation has 36 applications which require
10 regular security vulnerability remediation.

11 The 2022-2024 spend was approved for cost recovery in U-21297. See Exhibit A-
12 24 N3 Lines 145-148 for additional project details.

13

14 **Production Growth**

- 15 • The Company will invest \$4.3 million in the **Production Growth** project over the
16 course of 36-months ending December 31, 2025, and has a historical spend of \$9.1
17 million in 2022, as shown on line13 of Exhibit A-12 Schedule B5.7.4.

18 This project is to support the annual growth resulting from the ongoing increase in
19 data and business processing needs. This will be accomplished by provisioning
20 Just-In-Time computing power, storage capacity, database availability, and middle-
21 tier infrastructure. As technology products approach the end of the product
22 lifecycle, the Company must continue to make investments for supportability to
23 ensure that software and hardware is operational to run the business. This project
24 also enables IT business operations to perform within prescribed CPU-capacity,
25 storage thresholds, system response times, and availability.

Line
No.

1 The Company reflects a variance of \$9.0 million more in the 36 months ending
2 December 31, 2024, than was approved for cost recovery in U-21297.

3 In 2022, the company spent \$7.7 million more than previously approved for cost
4 recovery. This additional spend supported the purchase and deployment of
5 infrastructure components supporting the ADC, DDC and various service centers,
6 the purchase of 3-year software licenses to support the ADMS application, and the
7 supporting labor costs to deploy the purchased components. The existing
8 appliances were reaching end-of-life (EOL) at the end of 2022 and were planned
9 for replacement. The devices procured had more capacity and capability than the
10 infrastructure that was already in place and reduced the overall operational cost of
11 maintaining the existing infrastructure as the new purchase included warranty.

12 In 2023, new capabilities were implemented as planned, and an overspend of
13 \$0.8million was invested to install the additional purchased hardware from 2022.

14 The in-scope capabilities are related to outbound SMS features for Electric Damage
15 Claims, execution of SRS Red Hat 3-year license agreement, OSI GMS license
16 upgrade and proof of concept around gathering additional insights into possible
17 power outages by leveraging data to provide periodic status report data for active
18 Energy Bridges.

19 See Exhibit A-24 N3 Lines 149-152 for additional project details.

20

21 **Renewable Operations Application Health**

- 22 • The Company will invest \$0.4 million in the **Renewable Operations Application**
23 **Health** project over the course of 36-months ending December 31, 2025, and has a
24 historical spend of \$0.1 million in 2022, as shown on line 14 of Exhibit A-12
25 Schedule B5.7.4.

Line
No.

1 The Renewable Energy Operations organization performs monitoring, operations,
2 and maintenance of all Company-owned wind and solar assets. Operations include
3 predictive analytics on turbine health data, case management, work scheduling, and
4 work tracking. This project is to perform work to support sustainment of DTE
5 renewable assets and business processes. Renewable assets include IT
6 infrastructure, applications, and systems for the existing ten wind and seven
7 additional solar parks.

8 The scope of this investment includes required upgrades, new reports, interface
9 changes, and release management. Systems impacted include GE Digital, Wind-
10 SCADA, E-SCADA and GE connect adapter. The incremental changes needed for
11 monitoring and managing wind parks will support business process improvement
12 goals. Infrastructure work includes maintaining asset health for telecommunication
13 at all wind and solar parks, such as firewalls, routers, switches, and domain
14 controllers. Additionally, maintaining Renewable data center asset health such as
15 software upgrades and vendor support.

16 The 2022-2024 spend was approved for cost recovery in U-21297. See Exhibit A-
17 24 N3 Lines153-156 for additional project details.

18

19 **Supervisory Control and Data Acquisition (SCADA) System Improvement**

- 20 • The Company will invest \$1.4 million in the **Supervisory Control and Data**
21 **Acquisition (SCADA) System Improvement** project over the course of 36-
22 months ending December 31, 2025, and has a historical spend of \$0.6 million in
23 2022, as shown on line 15 of Exhibit A-12 Schedule B5.7.4.

24 DTE maintains critical applications which must comply with NERC-CIP
25 regulation, cyber security standards, and requirements for controlling, monitoring,
26 and supporting the electrical grid. SCADA monitors and controls the electrical

Line
No.

1 system continually, supports Energy Management System (EMS) and Generation
2 Management System (GMS) applications, and in the instance of an outage, provides
3 rapid solutions.

4 An objective of this initiative is to adhere to regulatory and security standards by
5 maintaining a safe cyber security posture. Additionally, the project will seek to
6 apply the latest vendor updates required to ensure uninterrupted functionality.

7 The 2022-2024 spend was approved for cost recovery in U-21297. See Exhibit A-
8 24 N3 Lines 157-160 for additional project details.

9

10 **System for Fossil Generation for Coal and Gas**

- 11 • The Company will invest \$1.2 million in the **System for Fossil Generation for**
12 **Coal and Gas** project over the course of 36-months ending December 31, 2025,
13 and has a historical spend of \$0.4 million in 2022, as shown on line 16 of Exhibit
14 A-12 Schedule B5.7.4.

15 Several of the Energy Supply applications such as Power Plant Performance
16 Management (P3M), the Laboratory Management System (LMS), PlantView and
17 the Overtime Management System (OTM), all require monthly releases as well as
18 hardware and software upgrades in alignment with accommodating vendor
19 releases. Frequently, we also need updates to the Generating Availability Data
20 System (GADS) reporting process, especially to reduce manual workarounds and
21 transition manual entry into automated or programmatic features. Data validity is
22 essential on this system as it not only affects operations but is also reviewed by
23 MISO and federal regulatory agencies such as the Federal Energy Regulatory
24 Commission (FERC). Therefore, failure to install required updates presents an
25 unacceptably high risk of data inaccuracy. The 2022-2024 spend was approved for

Line
No.

1 cost recovery in U-21297. See Exhibit A-24 N3 Lines161-164 for additional project
2 details.

3

4 Return-to-Health

5 **Q42. Can you explain in detail Plant & Field investment in the ‘Return-to-Health’**
6 **category?**

7 A42. The Company will invest \$19.8 million in the Return-to-Health category over the
8 course of 36-months ending December 31, 2025, as shown in lines 17 to 28 of the
9 Capital Expenditures Exhibit A-12 Schedule B5.7.4. The planned costs are
10 primarily across projects that are discussed further below:

11

12 **Advance Metering Infrastructure Field Collection System**

13 • The Company will invest \$4.6 million in the **Advance Metering Infrastructure**
14 **Field Collection System** project (AMI) over the course of 36-months ending
15 December 31, 2025, and has a historical spend of \$2.1 million in 2022, as shown
16 on line 17 of Exhibit A-12 Schedule B5.7.4.

17 The AMI Collection Engine (CE) requires updates to remain on vendor supported
18 technology as well as operate within established security standards. To support the
19 AMI Collection Engine SR7 project this return-to-health project will continue
20 through 2025 to ensure that the test environment and production environments are
21 upgraded to supported versions the addition of Collection Engine Application
22 Servers, as well as Collection Engine Database Servers. The project includes
23 purchasing new hardware and virtual components, including software, as well as
24 the required labor hours for testing, configuration, and development. The 2022-
25 2024 spend was approved for cost recovery in U-21297.

26 See Exhibit A-24 N3 Line168 for additional project details.

Line
No.

1

2 **Corporate Instance - Maximo Application Suite Upgrade Phase 1**

- 3 • The Company will invest \$3.8 million in **Corporate Instance - Maximo**
4 **Application Suite Upgrade** project over the course of 12-months ending
5 December 31, 2025, as shown on line 19 of Exhibit A-12 Schedule B5.7.4.

6 The corporate instance of Maximo Suite supports the Work Asset Management
7 function for the following several key business units at DTE, including Distribution
8 Electric Operations work and asset management. This asset and platform is critical
9 to serve the needs of our customers and service the grid. The current version of
10 Maximo 7 is scheduled to end vendor support in September of 2025. The newer
11 version of Maximo is more than just a traditional upgrade and it requires a complete
12 re-platforming as the underlying hardware and technical architecture is new. This
13 new platform is aligned with the latest technology and security standards and will
14 provide DTE a supported work and asset management platform. In 2025, the
15 company will complete the planning and design phases. The complete design and
16 finalized architecture design will support the future needs of the enterprise and
17 incorporate the resiliency and agility to respond to the needs of the future.

18
19 See Exhibit A-24 N3 Line 170 for additional project details.

20

21 **DO Equipment Engineering Transformer Database**

- 22 • The Company will invest \$0.4 million in **DO Equipment Engineering**
23 **Transformer Database** project over the course of 12-months ending December
24 31, 2024, as shown on line 21 of Exhibit A-12 Schedule B5.7.4.

25 Currently at DTE, the DO Equipment Engineering Transformer Database holds key
26 data related to our Engineering Transformers. This database uses old technology
27 and is not in alignment with the company efforts to invest in the strength and

Line
No.

1 reliability of our Distribution Operations assets through maximization of corporate
2 platform solutions. We need to invest in upgrading this asset to continue vendor
3 support, as well as migrate to the Maximo system for Asset and Work Management
4 functionality. This project will invest to first upgrade the current systems'
5 underlying technologies including the Operating system and Database Tooling to
6 the minimum extent that will enable currently supported functionality. Second, we
7 will work to migrate transformer assets to Maximo to track transformer data
8 attributes and maintenance activities. This will enable us to leverage Maximo Asset
9 Management and Work Management Processes.

10 See exhibit A-24 N3 Line 172 for additional project details.

11

12 **Maximo Platform Program**

13 • The Company will invest \$4.7 million in the **Maximo Platform Program** project
14 over the course of 36-months ending December 31, 2025, and has a historical spend
15 of \$4.1 million in 2022, as shown on line 24 of Exhibit A-12 Schedule B5.7.4.

16 IBM is the vendor for Maximo which is the Work and Asset Management solution.
17 It provides functionalities such as procurement of assets, preventative maintenance
18 of assets, install and replacements of assets, work order management, timekeeping,
19 and materials management. The Maximo system (version 7.6.0) was initially
20 implemented in 2015.

21 This project will implement configuration changes, new feature enhancements,
22 mobile enablement, and automated business processes for Work and Asset
23 Management.

24 The Company reflects a variance of \$3.7 million more in the 36 months ending
25 December 31, 2024, than was approved for cost recovery in U-21297. In 2022, \$2.2
26 million additional spend associated with the Work and Asset Management portion

Line
No.

1 of the Platform was required to support the upgrade of two end-of-life servers
2 (hardware), and Oracle Licenses and the required labor to build, test and deploy. In
3 2023, the incremental \$1.6 million was approved to meet demand of the business
4 units for configuration changes, new feature enhancements, mobile enablement,
5 and automated business processes for Work and Asset Management for across
6 multiple business units, Distribution Operation, Gas Operations, Energy Supply,
7 Renewables, Fleet and Facilities. The 2022-2024 spend was approved for cost
8 recovery in U-21297.

9 See Exhibit A-24 N3 Lines 176 -179 for additional project details.

10

11 IT Enhancements:

12 **DTE Electric Generation Capacity Enhancements**

13 **Q43. Can you explain in detail Plant & Field investment in the IT Enhancements**
14 **category?**

15 A43. Yes, the Company invested \$1.5 million in the **DTE Electric Generation**
16 **Capacity Enhancements** Project over the course of 12-months ending December
17 31, 2022, as shown on line 29 of Exhibit A-12 Schedule B5.7.4.

18 Under circumstances where available generation is unable to meet load demand,
19 the Company will communicate the need to customers under Interruptible
20 Agreements ¹¹that their load must be reduced. This load is either curtailed by the
21 Company directly, or by the customer, depending on the agreement. For both
22 agreement types, there are communication requirements that must be met prior to
23 the Company-initiated curtailment, or the customers risk a penalty for not initiating
24 their own load reduction. In either case, the Company risks being assessed high

¹¹ Interruptible Agreements are offered to /signed by large customers to reduce their load during high demand situations at DTE's request in turn for a better rate, in this case D8.

Line
No.

1 market penalties and loss of capacity credit when load reduction does not occur
2 within the required timeframe. Due to lower energy reserves in the market, the
3 potential for the frequency of these event has increased.

4 To address this growing need, the Company implemented a solution to manage the
5 required communication process to ensure successful communication with the
6 customer. The current process is a manual process shared between two business
7 units. Major Account Services (MAS) manages the customer account data, and
8 Generation Optimization (Gen Opts) manages the communication process to
9 enrolled customers. This process is time consuming for both business units to
10 manage, execute, and validate. The manual process is also vulnerable to human
11 error, which may result in corporate financial penalties.

12 See Exhibit A-24 N3 Line 187 for additional project details.

13

14 Strategic

15 **Q44. Can you explain in detail Plant & Field investment in the Strategic category?**

16 A44. The Company will invest \$20.6 million in the Strategic category over the course of
17 36-months ending December 31, 2025, as shown in lines 30 through 37 of the
18 Capital Expenditures - Exhibit A-12 Schedule B5.7.4. The planned costs are
19 primarily across projects that are discussed further below:

20

21 **Field Service Management- ClickSoft for EFO (Electric Field Operations)**

- 22 • The Company will invest \$0.5 million in the **Field Service Management-**
23 **ClickSoft for EFO (Electric Field Operations)** project over the course of 12-
24 months ending December 31, 2023, and has a historical spend of \$1.1 million in
25 2022, as shown on line 31 of Exhibit A-12 Schedule B5.7.4.

Line
No.

1 The vendor (ABB) supporting our field service work management system (Service
2 Suite) communicated in 2019 that their product would no longer be supported. This
3 system was originally implemented in 2007 and implemented its last upgrade in
4 2014. The end-of-life (EOL) classification by a vendor means they would no longer
5 provide critical security vulnerability remediation to ensure the software remains
6 safe from new cyber threats or support business process changes. Due to Service
7 Suite limitations, we are also unable to adapt to improvements in service
8 management requirements. This investment is critical to the Company's
9 Distribution Operations Field Service Management staff to provide a reliable and
10 secure business process application.

11 Aligned with the Company's cloud strategy, this project will implement a new field
12 management product, ClickSoft. This is a cloud-based product which enables
13 configuration within the product as opposed to the server. It optimizes automatic
14 routing of requests and changes for electric field operations and has an appointment
15 book functionality. Overall scope includes Timesheet functionality, development
16 of an additional 15 UI (User Interface) screens, Appointment Book, optimization
17 of crew routes, automatic assignment of work and system interfaces between
18 ClickSoft, Maximo, SAP CRM, and the Outage Management System. Additionally,
19 the Data Lake Platform effort will continue to move data from ClickSoft to the
20 Company data platform.

21 The project reflects a variance of \$0.5 million more in the 36 months ending
22 December 31, 2024, than was approved for cost recovery in U-21297. This increase
23 was primarily due to the delay and required integration with the ADMS project
24 which extended the resources over a longer period going through March 2023.
25 Specifically, the new product was required to interface with Service Suite as part

Line
No.

1 of standard migration activity, but also needed to successfully integrate with ADMS
2 as the new and advanced ADMS/OMS systems would send orders to the new
3 product after completing migration away from ServiceSuite. Alignment between
4 these two projects was critical. The 2022 spend was approved for cost recovery in
5 U-21297.

6 See Exhibit A-24 N3 Line 190 for additional project details.

7

8 **Storm Data Lakehouse**

- 9 • The Company will invest \$2.0 million in the **Storm Data Lakehouse** project over
10 the course of 12-months ending December 31, 2025, as shown on line 36 of Exhibit
11 A-12 Schedule B5.7.4.

12

13 Situational awareness is paramount during storms that impact our service territory
14 and result in customer outages. DTE emergency headquarters and storm roles need
15 timely and reliable access to customer, storm, job, and damage assessment
16 information to effectively manage crew resources and provide our customers with
17 accurate restoration information. The Storm Data Lakehouse will build upon our
18 current enterprise data lake infrastructure to provide a performant, unified access
19 layer for storm data and storm analytics needs.

20 This is provided today by having four separate databases in Azure to support the
21 user load requirements. By implementing the Storm Data Lakehouse, we can
22 reduce the number of databases and achieve cost optimization of cloud hosted
23 database charges.

24 Build on current enterprise data lake infrastructure (hosted in Azure cloud) to
25 implement a purpose-built Storm Data Lakehouse that provides a performant,
26 unified access layer for storm datasets and storm analytics needs. This will provide

Line
No.

1 fast, concurrent querying on large data volumes and provide the building blocks for
2 visualizations such as system outage screen (SOS) and situational awareness
3 reports. The Storm Data Lakehouse will provide data ingestion, data storage,
4 metadata, data and report visualization, and a data consumption layer that is
5 purpose built meet the needs for storm analytics, storm reporting, and situational
6 awareness of storm restoration efforts.

7 These benefits of this investment will provide timely and reliable data for outages,
8 regions, and customers impacted which will enable improved decision making for
9 storm restoration and enable better estimates for our customers.

10 This project is supporting the Company's storm response investments discussed in
11 Company Witness Hill's testimony (please refer to Q&A 17) and the customer
12 interaction improvements as discussed in Witness Hatsios' testimony (please refer
13 to Part 6).

14 See Exhibit A-24 N3 Line 198 for additional project details.

15

16 **Storm Simulation Lab**

- 17 • The Company will invest \$10.0 million in the **Storm Simulation Lab** project over
18 the course of 24-months ending December 31, 2025, as shown on line 37 of Exhibit
19 A-12 Schedule B5.7.4.

20 From 2021 through 2023, DTE experienced 13 severe weather-related events each
21 exceeding 110,000 unique customer outages, averaging 274,000 customers
22 impacted. These particularly impactful periods of outage are known within the
23 Company as "Catastrophic" or CAT Storm. During these CAT Storms, failures in
24 our IT systems such as Outage Management result both Customer and Operational
25 impact occurred 60% of the time. The average duration for CAT storm IT system
26 related outages is 6.8 hrs. During these events, customers may not have been able

Line
No.

1 to report outages, wire down events, hazards, etc. and could also experience delayed
2 or incorrect communications related to their restorations. Field crews would also
3 lack the ability to restore power, working quickly and efficiently from paper with
4 manual processes to plan, schedule, dispatch, and provide statuses of necessary
5 work. Analyzing the data from our IT major incidents shows that, during 60% of
6 those events, these kinds of system failures are directly caused by high load that is
7 beyond the design capacity of the related and interconnected systems. While the
8 Company has remediated these issues and corrected the system designs in reaction
9 to these storm events, we have no ability to identify these failure points before they
10 impact our customers and our employees.

11 The Storm Simulation Lab will identify the maximum throughput that each
12 system's design can handle and allow us to proactively make the necessary design
13 changes before a storm situation. After implementing the Storm Simulation Lab,
14 the number of IT major incidents incurred due to high load will be drastically
15 reduced with a target of 10% overall reduction in the frequency of IT outages
16 caused by load-related system issued during CAT Storm events. To address this
17 opportunity, the Company will invest in building a Storm Simulation Lab beginning
18 • in 2024. The lab will provide:

19 **Identify and build the “testing harness”** for storm critical systems – This
20 refers to the suite of tools and related environments required to conduct focused
21 • and largely automated end-to-end testing for the subset of systems identified as
22 being critical during Storm events.

23 **Execute the initial end-to-end test:** the Company will define the approach,
24 collect available data, and conduct the end-to-end tests needed to promote the
25 resiliency of our critical Storm systems. From this the Company can identify

Line
No.

1 the issues/ risks from the tests and translate these into actions for the appropriate
2 application teams

3 The Storm simulation lab will add the capability to test the end-to-end capabilities
4 of DTE's customer and outage systems fully proactively before each storm season
5 as well as after any significant changes to the associated IT systems.

6 The project aligns with DTE's priorities of ensuring the safe and reliable operation
7 of the electrical grid, restoring customers within 48 hours, and continuing to reduce
8 the frequency and duration of electric outages.

9 This project is supporting the Company's storm response investments discussed in
10 Company Witness Hill's testimony and the customer interaction improvements as
11 discussed in Witness Hatsios' testimony.

12 See Exhibit A-24 N3 Lines 199-200 for additional project details.

13

14 **Information Technology for Information Technology (IT for IT)**

15 **Q45. Can you describe the IT for IT Portfolio?**

16 A45. The Information Technology for IT Portfolio consists of capital projects that
17 represent investments made within IT for the enterprise as a whole or that enable
18 the functioning of the IT Department in support of the overall Company. These
19 capital project investments represent initiatives that are more periodic in nature than
20 ongoing year over year asset replacements or that bring significant new capabilities
21 to the IT department.

22

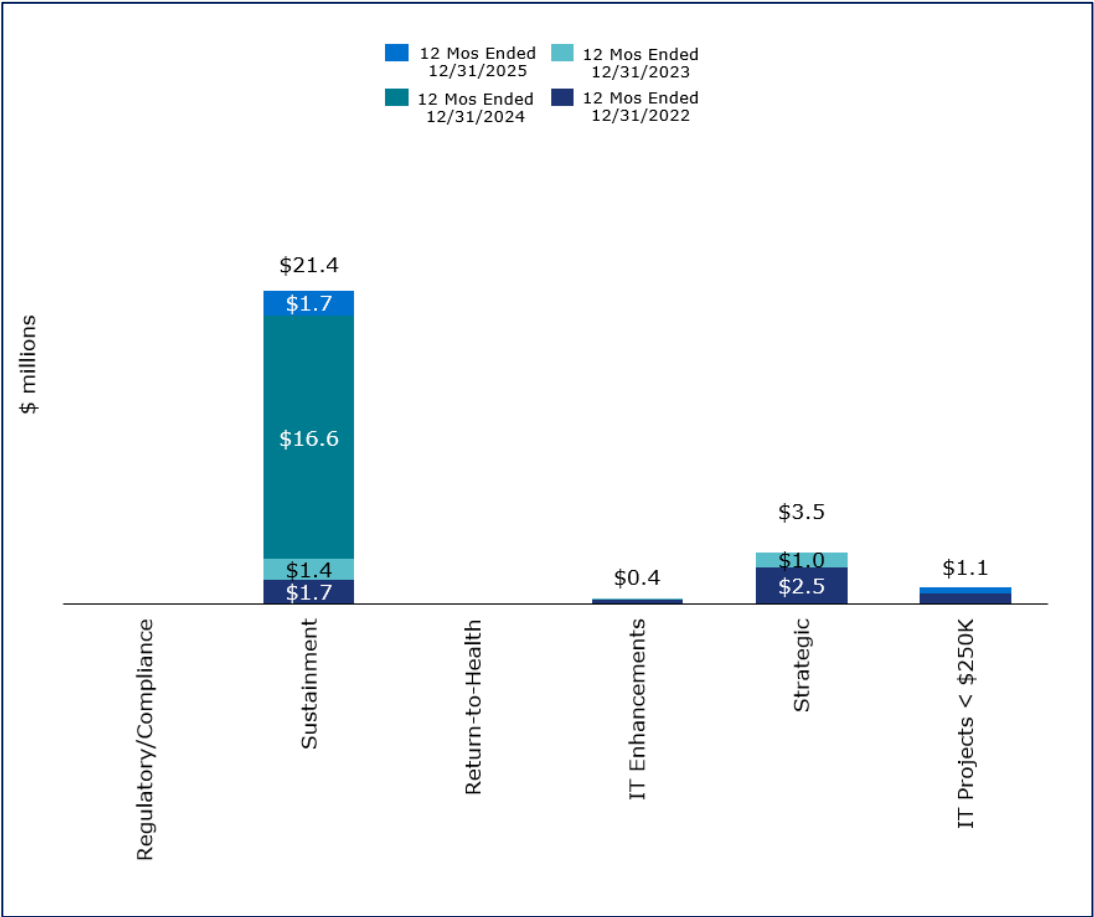
23 **Q46. What are the projected costs for investments in the IT for IT Portfolio?**

24 A46. As reflected on line 6 of Exhibit A-12 Schedule B5.7, page 1, capital expenditures
25 for IT for IT total \$5.2 million for the historical test year ended December 31, 2022,

Line
No.

1 \$19.1 million in the bridge period (for the 24 months ending December 31, 2024),
2 and \$2.1 million for the projected test period ending December 31, 2025.
3 The individual initiatives that fall into this area appear in Exhibit A-12 Schedule
4 B5.7.5. The synopses below generally provide the total spend for each line item the
5 Company requests in this rate case and the details regarding breakout by historical
6 period, projected bridge period, and projected test period, are each laid out in
7 Exhibit A-12 Schedule B5.7.5, in columns d, g and h, respectively. Figure 11
8 represents a high-level view of capital allocation within the portfolio.

9 **Figure 11 IT for IT Investment**



10

Line
No.

1 Sustainment

2 **IT for IT Application Health**

3 **Q47. Can you explain in detail IT for IT investment in the ‘Sustainment’ category?**

4 A47. Yes, the Company will invest \$19.7 million in the **IT for IT Application Health**
5 project over the course of 36-months ending December 31, 2025, and has a
6 historical spend of \$1.7 million in 2022, as shown on line 1 of Exhibit A-12
7 Schedule B5.7.5.

8 This project includes the production upgrades for IT Services Platform in 2022-
9 2025, including ServiceNow, GitHub, and Azure Devops. This ensures that
10 applications do not go out of support provided by the vendor and provides regular
11 application upgrades to mitigate security vulnerabilities. Yearly, we complete
12 version upgrades (two annually for ServiceNow, other applications as made
13 available by providing vendors). This project enhances workflows to improve
14 efficiency, adds new items to the service catalog to take advantage of the
15 ServiceNow solution to improve efficiency, enables automations, extends
16 discovery and event management to reduce unplanned outages, and manages
17 vulnerability identification and remediation. ServiceNow is essential to the
18 company’s IT governance and control and critical tool for supporting SOX and PCI
19 testing. The 2022-2024 spend was approved for cost recovery in U-21297.

20 See Exhibit A-24 N3 Line 204 for additional project details.

21

22 Strategic

23 **Q48. Describe IT for IT investment in the Strategic category.**

24 A48. The Company will invest \$1.0 million in the Strategic category over the course of
25 36-months ending December 31, 2025, as shown in lines 3 to 5 of the Capital

Line
No.

1 Expenditures - Exhibit A-12 Schedule B5.7.5. The planned costs are primarily
2 across projects that are discussed below:

3

4 **Cloud Management (Service Now)**

- 5 • The Company invested \$0.6 million in **Cloud Management (Service Now)** project
6 in the historical year ending December 2022, with a credit of (\$.065) in 2023, as
7 shown on line 4 of Exhibit A-12 B5.7.5. This project was approved for cost
8 recovery in U-21297, and the Company is seeking no additional recovery in this
9 instant case. The project reflects a variance of \$0.2 million less in the 36 months
10 ending December 31, 2024, than was approved for cost recovery in U-21297 due
11 to a credit from the vendor.

12

13 **Information Protection & Security**

14 **Q49. Can you describe the Information Protection & Security Portfolio?**

15 A49. Information Protection & Security (IPS) investments focus on the reliability of
16 security infrastructure as well as improving the Company's overall Security posture
17 in Information Technology (IT) and Operational Technology (OT). The Company
18 is seeking to improve the combined risk posture across IT and OT by implementing
19 a unified approach to security governance, covering both areas while still
20 acknowledging that security requirements and risk appetite may be different across
21 the two domains. Traditionally OT systems are more likely to be secure due to air
22 gap (limited or no external connectivity), protocols, and specialized functions -
23 while IT systems are all interconnected and use common protocols, standard
24 interfaces, and APIs. As the world moves to more interconnected systems, both
25 domains rely on the same infrastructure such as Windows, or Linux, both use the
26 same hardware, and connect via the same Transmission Control Protocol/Internet

Line
No.

1 Protocol networks. As a result, both systems face many of the same threats and
2 vulnerabilities. An IT system exploit can lead to OT system compromise just as it
3 can lead to an IT system compromise, so the Company's cybersecurity investment
4 uses a balanced approach to keep cybersecurity infrastructure healthy and
5 appropriately updated to address emerging threats, while we increase our focus on
6 maturing cybersecurity controls in the OT domain. The Company has established
7 this risk-based framework to apply uniform standards across both technologies.

8

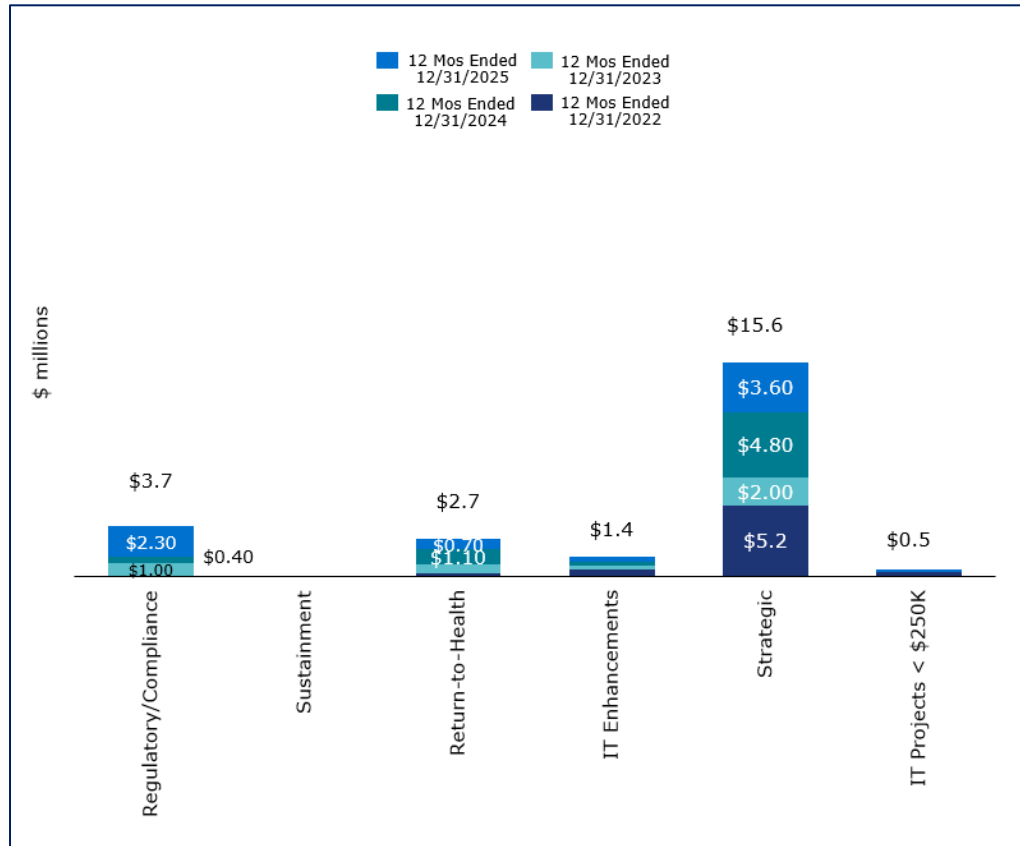
9 **Q50. What are the projected costs for investments in the IPS Portfolio?**

10 A50. As reflected on line 7 of Exhibit A-12 Schedule B5.7, page 1, capital expenditures
11 for IPS total \$6.1 million for the historical period ended December 31, 2022, \$10.6
12 million in the bridge period (for the 24 months ending December 31, 2024), and
13 \$7.2 million for the projected test period ending December 31, 2025.

14 The individual initiatives that fall into this area appear in Exhibit A-12 Schedule
15 B5.7.6. The synopses below generally provide the total spend for each line item the
16 Company requests in this rate case and the details regarding breakout by historical
17 period, projected bridge period, and projected test period, are each laid out in
18 Exhibit A-12 Schedule B5.7.6 in columns d, g and h, respectively. Figure 12
19 represents a high-level view of capital allocation within the portfolio.

Line
No.

1

Figure 12 IPS– IT Investment

2

3 Regulatory/Compliance

4 **Q51. Can you explain in detail IPS investment in the ‘Regulatory/Compliance’**
 5 **category?**

6 **A51.** Yes. The Company will invest \$3.7 million in the Regulatory/Compliance category
 7 over the course of 36-months ending December 31, 2025, as shown on line 1 to 4
 8 of Exhibit A-12 Schedule B5.7.6.

9

Line
No.

1 **Cloud Privilege Access Management**

- 2 • The Company will invest \$0.9 million in the **Cloud Privilege Access Management**
3 project over the course of 36-months ending December 31, 2025, as shown on line
4 1 of Exhibit A-12 Schedule B5.7.6.

5 This project will complete the migration of the legacy on-premise CyberArk
6 solution to SaaS based model. The scope of work will include the identification of
7 all privilege accounts across the Company in IT and OT¹² environments. The
8 CyberArk solution will be integrated with SailPoint for Identity Governance
9 lifecycle processes, ServiceNow ITSM, ServiceNow CMDB for automation, and
10 SEIM solution for alerting/monitoring. All secure privileged accounts on critical
11 assets across the enterprise IT and OT environment will be onboarded.

12 This project was previously approved in U-21297 and reflects a variance of \$0.4
13 million less in the 36 months ending December 31, 2024. This project was put on
14 hold and will resume in 2025, reflecting only a schedule shift in the project. The
15 2023 spend was approved for cost recovery in U-21297.

16 See Exhibit A-24 N3 Line 213 for additional project details.

17

18 **Security Information & Event Management (SIEM) End of Life Replacement**

- 19 • The Company will invest \$1.0 million in the **SIEM End of Life Replacement**
20 project over the course of 12-months ending December 31, 2025, as shown on line
21 2 of Exhibit A-12 Schedule B5.7.65.

22 The current Security Information & Event Management (SIEM) will be at end of
23 life and unsupported by the vendor at the end of 2025. The SIEM performs real-
24 time monitoring and analysis of security events, generates security alerts for
25 investigation, and logs security data for compliance and auditing purposes such as

¹² Operational Technology

Line
No.

1 North American Electric Reliability Corporation (NERC), Payment Card Industry
2 (PCI), Security Exchange Commission (SEC), Sarbanes-Oxley (SOX), and
3 Transportation Security Administration (TSA).

4 The above regulations mandate the logging of security events. Without an
5 operational SIEM, the logging would not occur, placing the Company at risk for
6 non-compliance. Additionally, the SIEM is used to monitor and detect cyber
7 security threats. Undetected cyber incidents could result in significant financial,
8 reputational, and customer data integrity risks to DTE.

9 See Exhibit A-24 N3 Line 214 for additional project details.

10

11 **Vendor Onboarding for DTE**

- 12 • The Company will invest \$0.8 million in the **Vendor Onboarding for DTE** project
13 over the course of 12-months ending December 31, 2025, as shown on line 3 of
14 Exhibit A-12 Schedule B5.7.65.

15 This project was previously approved for cost recovery in U-21297. The project
16 reflects a variance of \$0.6 million less in the 36 months ending December 31, 2024,
17 than was approved for cost recovery in U-21297. This is due to the project being
18 rescheduled to 2025.

19

20 **Vulnerability Scan Tool**

- 21 • The Company will invest \$1.0 million in the **Vulnerability Scan tool** project over
22 the course of 36-months ending December 31, 2025, as shown on line 4 of Exhibit
23 A-12 Schedule B5.7.65.

24 This project was approved for cost recovery in U-21297. The project reflects a
25 variance of \$0.46 million less in the 36 months ending December 31, 2024, than
26 was approved for cost recovery in U-21297. ~~This primarily due to a schedule~~

Line
No.

1 ~~change, shifting the project start to 2025 and carrying over the implementation into~~
2 ~~2026. There is no change to planned scope or cost.~~

3
4 The delay in the project by one year was to respond to economic conditions within
5 the company and to review IT investment priorities. In addition, the company
6 identified a reduction in demand spend by removing the forecasted expenses related
7 to ServiceNow CMDB (Configuration Management Database) license costs, which
8 will not be required specifically to execute this project.

9

10 Return-to-Health11 **Q52. Can you explain in detail IPS investment in the ‘Return-to-Health’ category?**

12 A52. The Company will invest \$2.5 million in the Return-to-Health category over the
13 course of 36-months ending December 31, 2025, as shown in lines 5 to 7 of the
14 Capital Expenditures – Exhibit A-12 Schedule B5.7.6. The planned costs are
15 primarily across projects that are discussed further below:

16

17 **Cloud Security**

- 18 • The Company will invest \$1.2 million in the **Cloud Security project** over the
19 course of 36-months ending December 31, 2025, as shown on line 5 of Exhibit A-
20 12 Schedule B5.7.6.

21 This investment will deliver asset monitoring and improve our cloud security
22 disposition. Monitoring today is reactive which creates delays in our response to
23 cyber security- related events. The solution to be implemented will provide
24 proactive monitoring capabilities that allows DTE to respond faster to security
25 events – thereby reducing risk and lowering impact to DTE systems. This will also
26 allow DTE to address unmonitored assets (applications and servers). The

Line
No.

1 recommended solution is aligned with the Company's platform roadmap. The
2 2023-2024 spend was approved for cost recovery in U-21297.

3 See Exhibit A-24 N3 Line 220 for additional project details.

4

5 **Cyber Security Defense Center (CSDC) Growth and Lifecycle Management**

- 6 • The Company will invest \$1.0 million in the **Cyber Security Defense Center**
7 **(CSDC) Growth and Life Cycle Management** project over the course of 36-
8 months ending December 31, 2025, and has a historical spend of \$0.2 million in
9 2022, as shown on line 6 of Exhibit A-12 Schedule B5.7.6.

10 This project will enable cyber security monitoring capabilities and hardware life
11 cycle to maintain detection of and defense against threats to DTE cyber assets. DTE
12 will continue to expand cyber defense & intelligence monitoring to meet the ever-
13 growing threats. This project will utilize existing tools and processes to maintain
14 our ability to monitor and respond to threats and incidents more effectively. It will
15 entail the purchase of additional licenses for the Security Information and Event
16 Monitoring (SIEM) to accommodate increasing security log volume, purchase of
17 additional licensing for existing threat intelligence feeds to accommodate
18 increasing security alerts, and management of the hardware life cycle of packet
19 capture hardware. The investment will also cover network taps, and sensors that
20 ensure network monitoring remains operational.

21 The 2022-2024 spend for this project was approved for cost recovery in in U-21297
22 and will conclude in 2025.

23 See Exhibit A-24 N3 Lines 221-224for additional project details.

24

Line
No.

1 **IPS Operations PAWS and DC Replacement**

- 2 • The Company will invest \$0.3 million in the **IPS Operations PAWS and DC**
3 **Replacement** project over the course of 12-months ending December 31, 2024, as
4 shown on line 7 of Exhibit A-12 Schedule B5.7.6.

5 Cyber Operations maintains and supports several cyber assets that reach end of life
6 each year. To maintain security operations for DTE identities, key and critical
7 assets for these systems require hardware, software replacements/upgrades,
8 additional capabilities added to the platforms to support security growth, maintain
9 a healthy risk posture, and minimize risks from insider/outsider threats. This
10 supports the Company's best operated strategy and aligns with our Cyber Security
11 Strategy. Two such assets are Privileged Access Workstations (PAW) and Domain
12 Controllers (DC).

13 See Exhibit A-24 N3 Line 225 for additional project details.

14

15 IT Enhancements

16 **Endpoint Protection**

17

18 **Q53. Describe IPS investment in the IT Enhancements category.**

19 A53. The Company invested \$0.9 million in the **Endpoint Protection** project over the
20 course of 36-months ending December 31, 2025, and has a historical spend of \$0.5
21 million in 2022, as shown on line 8 of Exhibit A-12 Schedule B5.7.65.

22 This project was previously approved in U-21297 and reflects a variance of \$0.2
23 million more in the 36 months ending December 31, 2024, than was approved due
24 to the 20% disallowance from the commission.

25 DTE uses Endpoint Protection as a standard tool of choice to secure end user
26 workstations as well as Windows based servers. It provides the last layer of

Line
No.

1 protection to prevent malware and malicious attacks, as well as to provide
2 remediation and investigation capabilities. The 2022-2024 spend was approved for
3 cost recovery in U-21297.

4 See exhibit A-24 N3 Line 229 for additional project details.

5

6 Strategic

7 **Q54. Can you explain in detail IPS investment in the Strategic category?**

8 A54. The Company will invest \$10.4 million in the Strategic category over the course of
9 36-months ending December 31, 2025, as shown in lines 9 to 17 of the Capital
10 Expenditures – Exhibit A-12 Schedule B5.7.6. The planned costs are primarily
11 across projects that are discussed further below:

12

13 **Automated Provisioning**

14 • The Company will invest \$3.9 million in the **Automated Provisioning** project over
15 the course of 36-months ending December 31, 2025, and has a historical spend of
16 \$1.6 million in 2022, as shown on line 9 of Exhibit A-12 Schedule B5.7.65.

17 This planned investment will include the work needed to replace the Oracle
18 Waveset system with SailPoint because the current product went out of support by
19 the vendor in 2019. An unsupported product cannot be updated to keep up with the
20 pace of changing technology, cyber security, or regulatory requirements. Migration
21 to the SailPoint system will provide commensurate features, with the added ability
22 to integrate role-based access control, and scalability in support of future need.

23 This project was previously approved in U-21297 and reflects a variance of \$1.1
24 million more in the 36 months ending December 31, 2024, than was approved for
25 cost recovery due to the \$0.7 million (20%) disallowed by the Commission. The
26 balance of \$0.4 million was spent in 2022 to pull ahead 10 applications from 2023

Line
No.

1 into 2022 and the incremental cost associated with the increase labor cost to support
2 this scope pull ahead. The 2022-2024 spend was approved for cost recovery in U-
3 21297.

4 See Exhibit A-24 N3 Line 233 for additional project details.

5

6 **Azure Active Directory Federation Implementation**

- 7 • The Company will invest \$1.2 million in the **Azure Active Directory Federation**
8 **Implementation** project over the course of 36-months ending December 31, 2025,
9 and has a historical spend of \$0.06 million in 2022, as shown on line 10 of Exhibit
10 A-12 Schedule B5.7.6

11 The existing on-premise multifactor authentication (MFA) solution limits our
12 ability to update user authentication without manual intervention. This project will
13 implement/configure AD to support internet facing systems and Software as a
14 Service (SaaS) cloud applications. As the Company increases its use of cloud
15 computing, it is imperative that it continues to ensure authentication is enabled for
16 all Company applications, including cloud-based solutions. With the
17 implementation of Active Directory for cloud applications, single sign-on for
18 external facing applications will be enabled, ensuring password security and ease
19 of use. The 2022-2024 spend was approved for cost recovery in U-21297.

20 See Exhibit A-24 N3 Line 237 for additional project details.

21

22 **Cyber Excellence Plan (CEP) Program**

- 23 • The Company will invest \$0.9 million in the **Cyber Excellence Plan (CEP)**
24 **Program** project over the course of 36-months ending December 31, 2025, and has
25 a historical spend of \$0.3 million in 2022, as shown on line 11 of Exhibit A-12
26 Schedule B5.7.6.

Line
No.

1 The Company established the CEP program to build a cross-business-unit
2 collaborative team to identify and address cyber security issues that expose the
3 Company's operational technology infrastructure at its facilities.

4 In March 2022, DTE hosted an Edison Electric Industry (EEI) Culture of Security
5 (COS) Peer Review with the intent to receive and share best practice
6 recommendations with industry peers regarding the DTE cyber and physical
7 security landscape. Given the recommendations, DTE elected to focus the Cyber
8 Excellence program on (1) the cyber security metrics collection process and
9 presentation enhancements during 2023, in addition to (2) continued expansion of
10 the DTE cyber security monitoring capability for Operational Technology during
11 2023-2024.

12 The project cost was approved for recovery in U-21297 through 2024 and is seeking
13 recovery for 2025 spend projected in the current case. In 2025, additional network
14 sensors will be purchased and installed in specific critical electric generation OT
15 network locations prioritized by electric generation capacity. Deploying these
16 network sensors will aid in early detection of malicious cyber security events in
17 these critical networks. The 2022-2024 spend was approved for cost recovery in U-
18 21297.

19 See Exhibit A-24 N3 Line241 for additional project details.

20

21 **Enterprise Mobility Management**

- 22 • The Company will invest \$0.5 million in the **Enterprise Mobility Management**
23 project over the course of 36-months ending December 31, 2025, shown on line 12
24 of Exhibit A-12 Schedule B5.7.6.

25 The Company is placing increased emphasis on mobility and the ability to work
26 from anywhere, which includes the planned introduction of a personal device

Line
No.

1 policy. The provisioning and management of the increasing number of Company
2 and personal devices accessing our networks will require a more capable enterprise
3 mobility management platform. DTE has deployed Enterprise Mobility
4 Management (EMM) platform, a Microsoft solution, for managing devices that will
5 process, store, or transmit DTE data on Company-owned devices and “Bring Your
6 Own Devices” (BYOD). The continuing investment will support securing corporate
7 owned devices and executive level devices. This includes securing them and
8 bringing advanced capabilities to increase end user experience. This project will
9 provide a system and associated set of policies to manage and secure all mobile
10 devices accessing Company resources and data.

11 This project reflects a variance of \$0.4 million less than approved for cost recovery
12 in U-21297 due to late project start due to limited resources and project priorities
13 at the start of the year in FY23 and a transfer of 340k to the Mobile Device
14 Management demand to support deploying EMM policies and processes to all DTE
15 owned mobile devices. The 2023 spend was approved for cost recovery in U-21297.
16 See Exhibit A-24 N3 Line 243 for additional project details.

17

18 **Network Access Control**

- 19 • The Company will invest \$1.8 million in the **Network Access Control** project over
20 the course of 36-months ending December 31, 2025, and has a historical spend of
21 \$0.2 million in 2022, as shown on line 13 of Exhibit A-12 Schedule B5.7.6.

22 Due to the heightened global cyber security risk, this project continuation is
23 required. This investment will provide increased network security when these
24 devices attempt network access, and will unify endpoint security technology, user
25 and system authentication, and network security enforcement.

Line
No.

1 This project was approved in U-21297 through the bridge period and reflects a
2 variance of \$1.7 million less than approved for cost recovery in U-21297. This
3 reflects a schedule shift of the project implementation from 2023-2024 to 2024-
4 2025. The 2022-2024 spend was approved for cost recovery in U-21297.

5 See Exhibit A-24 N3 Line 247 for additional project details.

6

7 **Ransomware Protection**

- 8 • The Company invested \$2.5 million in the **Ransomware Protection** project over
9 the course of 12-months ending December 31, 2022, as shown on line 14 of Exhibit
10 A-12 Schedule B5.7.6.

11 This project reflects a variance of \$2.2 million more than approved for cost
12 recovery in U-21297. In 2022, the Company was required to respond to the TSA
13 mandate to implement the additional protection actions in support of the mandate
14 which is reflected in the increased spending.

15 The Ransomware Protection project will advance cyber security recovery
16 capability by means of automated data isolation security analytics, and
17 recovery/remediation to protect against ransomware attacks. Ransomware attacks
18 are becoming more common and sophisticated, and the Company's cyber security
19 must mitigate these risks to protect Company data. This investment provides data
20 to make evidence-based decisions and will allow the Company to proactively
21 prevent, detect, and respond quickly to ransomware attacks threatening our
22 organization.

23 Technology was purchased including Data Vault Domain for hosting our Critical
24 Applications and from which related data can be recovered in case of a
25 Ransomware attack as part of a Cyber Recovery Plan. This separate isolated, air-

Line
No.

1 gapped, infrastructure will serve as a vault with separation preventing ransomware
2 from traversing across the network and locking systems.

3 Initial infrastructure is required to build out the vaulting capability along with first
4 year of storage. Then, year-over-year storage for the vault will be purchased in
5 subsequent years.

6 See Exhibit A-24 N3 Line 248 for additional project details.

7

8 **Ransomware Recovery**

- 9 • The Company will invest \$1.4 million in the **Ransomware Recovery (previously**
10 **called Ransomware Protection)** project over the course of 36-months ending
11 December 31, 2025, as shown on line 15 of Exhibit A-12 Schedule B5.7.6.

12 Ransomware attacks are becoming more sophisticated and DTE Cyber security
13 must mitigate these risks to protect DTE Energy data. Furthermore, the TSA has
14 mandated Cyber security controls requiring offline storage for recovery solutions.

15 This project was approved for cost recovery in U-21297 through 2024 and the 2025
16 scope reflects the continuation of this project, for which the company is seeking
17 recovery in the current case. The 2023-2024 spend was approved for cost recovery
18 in U-21297.

19 See Exhibit A-24 N3 Line251 for additional project details.

20

21 **Recovery Manager for AD- Disaster Recovery Edition**

- 22 • The Company will invest \$0.7 million in the **Recovery Manager for AD- Disaster**
23 **Recovery Edition** project over the course of 12-months ending December 31,
24 2024, as shown on line 16 of Exhibit A-12 Schedule B5.7.6.

25 This project will advance the Company's position as part of our cyber defense with
26 respect to disaster recovery. The implementation of DRE can reduce recovery time

Line
No.

1 to within 24-48 hours. This is critical to the Company's operations as 95% of
2 operating applications depend on Active Directory (AD) for authentication, as do
3 all Windows servers and systems.

4 This project will procure and implement a modern solution for disaster recovery.

5 Ransomware attacks are a growing threat, with the global average downtime due to
6 such attacks being 21 days in 2020; taking an average of 287 days for businesses to
7 fully recover from these attacks. Given the crucial role that AD plays in the
8 Company's operations, an attack on AD could have severe implications for the
9 Company and our customers.

10 See Exhibit A-24 N3 Line 252 for additional project details.

11

12 **Threat Intel Module**

13 • The Company will invest 0.043 million in the **Threat Intel Module** project over
14 the course of 24-months ending December 31, 2024, and has a historical spend of
15 \$0.5 million in 2022, as shown on line 17 of Exhibit A-12 Schedule B5.7.6.

16 Threat intelligence is information about cyber threats and malicious actors and can
17 come from several sources including governmental sources, peer companies, open
18 source, and from the dark web. DTE currently receives threat intel from vendors,
19 government authorities (DHS, DOE, FBI, etc.), Information Sharing and Analysis
20 Centers, peer companies, and DTE's internal sources. DTE will establish a threat
21 intelligence platform integrated with our cyber event ticketing system to aid in
22 reducing cyber risk by quickly associating shared threat intel with internal cyber
23 alerts generated by our security monitoring systems. This effort will automate the
24 intake and handling of threat intelligence data to mitigate new cyber threats against
25 our computing environment. Automation of this data means that we are not only

Line
No.

1 aware of potential threats, but we are able to more efficiently ingest and handle
2 threat data to make decisions that will ensure cyber resilience.

3 This project was approved for cost recovery in U-21297. The project reflects a
4 variance of \$0.6 million less in the 36 months ending December 31, 2024. This is
5 due to external resource labor savings with AI capabilities available in the Palo Alto
6 XSOAR solution.

7

8 **Infrastructure Operations**

9 **Q55. Can you describe the Infrastructure Operations Portfolio?**

10 A55. The Infrastructure Operations Portfolio is responsible for the design,
11 implementation, and secure operation of the Company's overall IT Infrastructure.
12 This includes all the Company's physical IT assets (datacenters, servers,
13 computers, network devices, and the licensed software that supports those assets).
14 This portfolio is responsible for the day-to-day operation of these assets, the overall
15 health of the assets (including operational growth, capacity, and availability
16 standards), and from a project perspective, the enhancement of these assets to meet
17 project requirements.

18

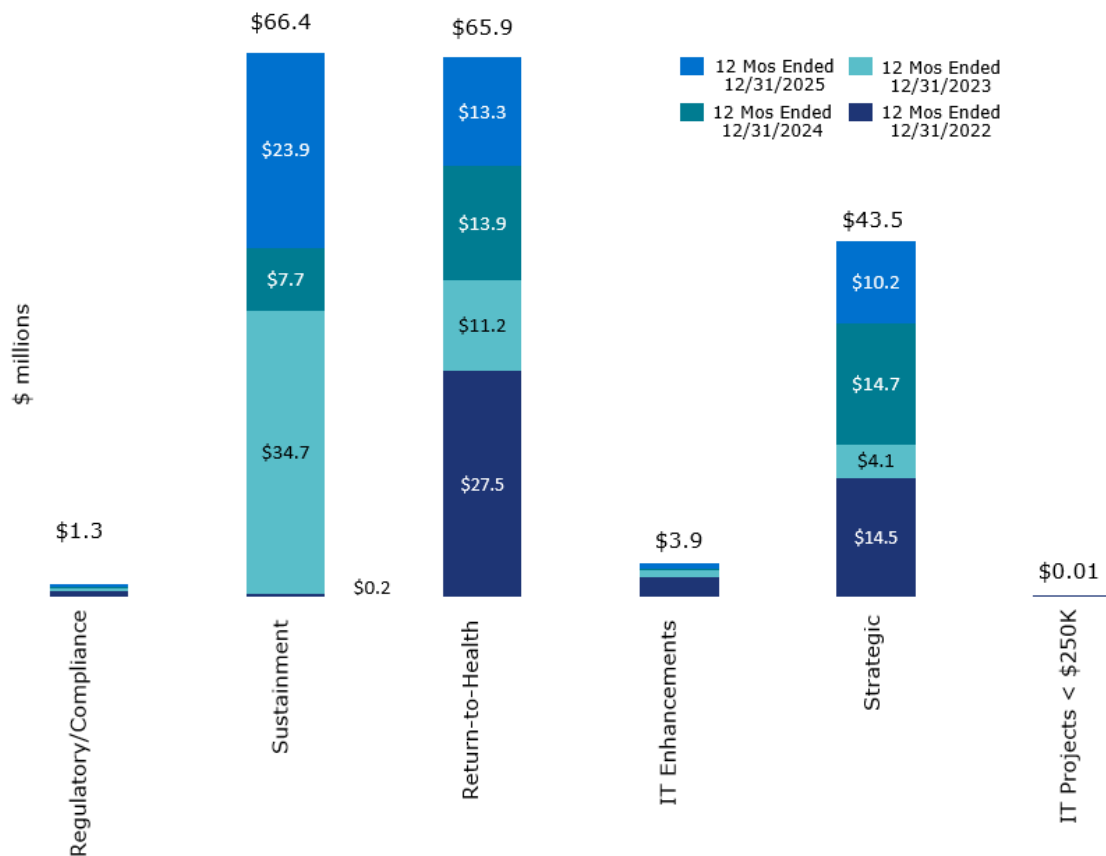
19 **Q56. What are the projected costs for investments in the Infrastructure Operations**
20 **Portfolio?**

21 A56. As reflected on Line 8 of Exhibit A-12 Schedule B5.7, page 1, capital expenditures
22 for Infrastructure Operations total \$45.1 million for the historical test year ended
23 December 31, 2022, \$87.8 million in the bridge period (for the 24 months ending
24 December 31, 2024), and \$48.3 million for the projected test period ending
25 December 31, 2025.

Line
No.

The individual initiatives that fall into this area appear in Exhibit A-12 Schedule B5.7.7. The synopses below generally provide the total spend for each line item the Company requests in this rate case and the details regarding breakout by historical period, projected bridge period, and projected test period, are each laid out in Exhibit A-12 Schedule B5.7.7, in columns d, g and h, respectively. Figure 12 represents a high-level view of capital allocation within the portfolio.

Figure 13 Infrastructure Operations – IT Investment



Regulatory/Compliance

Q57. Can you explain in detail the Infrastructure Operations investment in the Regulatory/ Compliance category?

Line
No.

1 A57. The Company will invest \$0.7 million in the Regulatory/Compliance category over
2 the course of 36-months ending December 31, 2025, as shown on lines 1 & 2 of the
3 Capital Expenditures – Exhibit A-12 Schedule B5.7.7.

4

5 **Tower and Lighting Inspections and Repairs**

- 6 • The Company will invest \$0.7 million in the **Tower and Lighting Inspections and**
7 **Repairs** project over the course of 36-months ending December 31, 2025, with a
8 historical spend of \$0.3 million in 2022, as shown in line 2 of Exhibit A-12
9 Schedule B5.7.7.

10 The Tower and Lighting Inspections and Repairs project is an annual effort that
11 evaluates the integrity of both the physical towers that carry the DTE network
12 telecommunications lines and the real estate upon which the towers are built. These
13 towers are used to provide reliable, efficient, and redundant network systems that
14 are used by DTE IT and DTE Business Units in support of our customers. The FCC
15 regulations ensure the capability, security, and safety of these lines in the
16 transmission of DTE data. The Commission approved this program in previous rate
17 case, and the capital spend included in this case is incremental and builds upon
18 work/spend approved previously. The 2022-2024 spend was approved for cost
19 recovery in U-21297.

20 See Exhibit A-24 N3 Lines 260 for additional project details.

21

22 Sustainment

23 **Q58. Can you explain in detail the Infrastructure Operations investment in the**
24 **Sustainment category?**

25 A58. The Company will invest \$66.2 million in the Sustainment category over the course
26 of 36-months ending December 31, 2025, as shown in lines 3 to 14 of the Capital

Line
No.

1 Expenditures – Exhibit A-12 Schedule B5.7.7. The planned costs are primarily
2 across projects that are discussed further below:

3

4 **Backup Environmental Growth**

- 5 • The Company will invest \$1.2 million in the **Backup Environmental Growth**
6 project over the course of 36-months ending December 31, 2025, and has a
7 historical spend of \$0.2 million in 2022, as shown on line 4 of Exhibit A-12
8 Schedule B5.7.7.

9 The Backup Environmental Growth Project for 2022 through 2024, will ensure that
10 the information technology devices that maintain the business data of DTE have
11 the appropriate amount of capability necessary to create and securely store the
12 backup data.

13 The project reflects a variance of \$0.6 million less in the 36 months ending
14 December 31, 2024, than was approved for cost recovery in U-21297. This
15 reduction in planned spend was prioritized for the renewal of Dell Licenses, as
16 discussed in Server Engineering Support Services project further below. The Dell
17 License purchase included the required backup environmental requirements to
18 support this project as planned. The 2022-2024 spend was approved for cost
19 recovery in U-21297.

20 See Exhibit A-24 N3 Line 265 for additional project details.

21

22 **Collaboration Application Health**

- 23 • The Company will invest \$24.8 million in the **Collaboration Application Health**
24 project over the course of 36-months ending December 31, 2025 with a historical
25 spend of \$0.7 million in 2022, as shown on line 5 of Exhibit A-12 Schedule B5.7.7.

Line
No.

1 This project was previously approved in U-21297 and reflects a variance of \$4.7
2 million more in the 36 months ending December 31, 2024, than was approved for
3 cost recovery due to 20% disallowance by the Commission.

4 The collaboration platform is a group of systems that enable employee productivity
5 through collaborative communications, meetings, email, calendaring, instant
6 messaging, co-authoring, and calling. Foundational Microsoft 365
7 upgrades/migrations authorized and implemented in years past made this possible.
8 Ongoing application and collaboration enhancement enable DTE's workforce
9 model.

10 In addition to infrastructure enhancements, we have added tools and intelligence to
11 the investment and have implemented solutions such as Hive, which enables an
12 Enterprise-Wide Live Meeting and was not possible prior to this implementation.
13 This software allows our Company's senior leadership to conduct live meetings
14 with all employees at one time, in an interactive environment. The 2022-2024 spend
15 was approved for cost recovery in U-21297.

16 See Exhibit A-24 N3 Lines 269 for additional project details.

17

18 **Dell Storage Hardware Refresh**

19 • The Company will invest \$0.3 million in the **Dell Storage and Hardware Refresh**
20 project over the course of 24-months ending December 31, 2024, as shown on line
21 6 of Exhibit A-12 Schedule B5.7.7.

22 The existing lease for storage infrastructure is expiring end of 2023. In order to
23 maintain enterprise storage services, a new agreement must be executed. This
24 impacts the Company's storage capabilities that supports all servers and enterprise-
25 wide applications hosted on these servers.

26 See Exhibit A-24 N3 Line 270 for additional project details.

Line
No.

1

2 **Endpoint End of Life Electric Support Services**

- 3 • The Company will invest \$2.7 million in the **Endpoint End of Life Electric**
4 **Support Services** project over the course of 36-months ending December 31, 2025,
5 and has a historical spend of \$0.6 million in 2022, as shown on line 7 of exhibit A-
6 12 Schedule B5.7.7.

7 To meet the organizational and business driven needs assigned to Endpoint
8 engineering services or functions, IT partnered with a third-party service provider
9 to provide the necessary labor support to meet demand. This spend reflects the
10 capital labor portion of endpoint engineering services the Company uses for the
11 deployment of the capital assets purchased under the Endpoint EOL program. The
12 2022-2024 spend was approved for cost recovery in U-21297.

13 See Exhibit A-24 N3 Line 274 for additional project details.

14

15 **Enterprise Monitoring Licensing**

- 16 • The Company will invest \$5.0 million in the **Enterprise Monitoring Licensing**
17 project over the course of 36-months ending December 31, 2025, as shown on line
18 8 of Exhibit A-12 Schedule B5.7.5.

19 The project reflects a variance of \$3.4 million less in the 36 months ending
20 December 31, 2024, than was approved for cost recovery in U-21297. This was
21 due to pull ahead of the Dynatrace licensing purchase to 2022 prior to expiration
22 date.

23 This project will provide visibility into the IT ecosystem along with contextual and
24 situational awareness of the health of all IT assets and services. The Company has
25 implemented Dynatrace and NetScout to support monitoring of DTE's internal and

Line
No.

1 external facing applications. Specifically, this technology allows for predictive
2 alters to mitigated unnecessary application interruptions or unplanned outages.

3 See Exhibit A-24 N3 Line 275 for additional project details.

4

5 **Enterprise Monitoring Strategy Operational Growth**

- 6 • The Company will invest \$2.2 million in the **Enterprise Monitoring Strategy**
7 **Operational Growth** project over the course of 36-months ending December 31,
8 2025, and has a historical spend of \$0.5 million in 2022, as shown on line 9 of
9 Exhibit A-12 Schedule B5.7.7.

10 Investment in Enterprise Monitoring Operational Growth expands the monitoring
11 of critical applications, infrastructure, security, services, and user experiences. This
12 expanded monitoring provides increased ability to extract and present data logs,
13 implement real-time decision-making dashboards, provide analysis of application
14 infrastructure, security, inter-connectivity, services, and proactively respond to
15 increased demand on the IT infrastructure from processing business systems and
16 user load.

17 See Exhibit A-24 N3 Line 279 for additional project details.

18

19 **Field Communications Network (FCN) Growth and Upgrade**

- 20 • The Company will invest \$1.1 million in the **Field Communications Network**
21 **(FCN) Growth and Upgrade** project over the course of 36-months ending
22 December 31, 2025, and has a historical spend of \$0.4 million in 2022, as shown
23 on line 10 of the Exhibit A-12 Schedule B5.7.7.

24 The FCN Growth project is a continuing program designed to provide redundant
25 communication and control functionality for the Company's field devices (Routers,
26 Switches and Hubs) that monitor and control the operation of the bulk-electrical-

Line
No.

1 system network. This program replaces devices that are reaching the end of useful
2 life, adds devices to accommodate load or geographical growth, and adds
3 functionality, automation, and redundancy to the alternate System Operations
4 Center location. Annually, this effort in both hardware and labor requires
5 investment of \$0.4M to ensure the communication hardware requiring replacement,
6 upgrade, or reconfiguration meets the requirements of the business and our
7 customers. The 2022-2024 spend was approved for cost recovery in U-21297.
8 See Exhibit A-24 N3 Line 283 for additional project details.

9

10 **Network Hardening and Operations**

- 11 • The Company will invest \$1.7 million in the **Network Hardening and Operations**
12 project over the course of 36-months ending December 31, 2025, and has a
13 historical spend of \$0.6 million in 2022, as shown on line 11 of Exhibit A-12
14 Schedule B5.7.7.

15 The Company intentionally does not maintain the internal staffing levels required
16 to meet the growing demands (both project and operational) of Network
17 Engineering services/functions across the enterprise. To meet the organizational
18 and business driven needs assigned to network engineering for projects or
19 operational system upgrades, Infrastructure and Operations partnered with a third-
20 party service provider to provide the necessary labor support to meet demand. This
21 spend reflects the capital labor portion of Network Engineering services the
22 Company uses for the deployment of the capital assets purchased under the
23 Network EOL program.

24 This project reflects a variance of \$0.8 million more than was approved for cost
25 recovery in U-21297. In 2022, a contract renewal of Infloblox was required.
26 Infoblox is a critical communication infrastructure used by the entire company.

Line
No.

1 This infrastructure allows all wired and wireless users to connect to the Company's
2 network, obtain IP address assigned, query and connect to internal and external
3 devices. Without this agreement in place the Company's employees would be
4 unable to communicate on DTE's networks.

5 In 2023, the spend was \$0.5 million more than approved due to hardware purchases
6 made in 2022 that were unable to be received until 2023 due to vendor supply chain
7 issues. The 2022-2024 spend was approved for cost recovery in U-21297.

8 See Exhibit A-24 N3 Line 287 for additional project details.

9

10 **Palo Alto Capital License Purchase**

- 11 • The Company will invest \$5.5 million in the **Palo Alto Capital License Purchase**
12 project over the course of 12-months ending December 31, 2025, shown on line 12
13 of Exhibit A-12 Schedule B5.7.7.

14 The Company utilizes Palo Alto solution to ensure functionality and supportability
15 of network security assets required for the Company's IT and OT/Control networks.
16 The current support agreement will expire in 2025 requiring a 3-year license
17 purchase. External and internal security threats continue to increase and evolve
18 throughout DTE's IT and OT/Control networks. DTE leverages Palo Alto based
19 security infrastructure for securing our network and providing the needed threat
20 protection.

21 This is a mandatory investment for the Company to ensure security infrastructure
22 up to date and supported.

23 See Exhibit A-24 N3 Line 288 for additional project details.

24

Line
No.

1 **Server Engineering Support Services**

2 • The Company will invest \$16.2 million in the **Server Engineering Support**
3 **Services** project over the course of 36-months ending December 31, 2025, and has
4 a credit of -\$3.5 million in the historical period ending December 31,2022, as shown
5 on line 13 of Exhibit A-12 Schedule B5.7.7.

6 To meet the organizational and business driven needs assigned to server engineering
7 for projects or operational system upgrades, IT partnered with a third-party service
8 provider to provide the necessary labor support to meet demand. The planned spend
9 reflects this capital labor supporting the deployment of the capital assets purchased
10 under Server and Database Engineering & Operations.

11 The project reflects a variance of \$2.2 million more in the 36 months ending
12 December 31, 2024, than was approved for cost recovery in U-21297. In 2023, the
13 Company executed the multi-year Dell Storage agreement resulting in variance to
14 previously requested and approved spend. The software and hardware provided by
15 this agreement supports enterprise applications, user storage, and backup and
16 disaster recovery. Not renewing this agreement would mean enterprise and customer
17 facing applications would eventually cease to function and our ability to recover
18 from data loss or app failures would be severely impeded if not impossible. The
19 2022-2024 spend was approved for cost recovery in U-21297.

20 See Exhibit A-24 N3 Line 292 for additional project details.

21

22 **VMWare License Purchase**

23 • The Company will invest \$5.6 million in the **VMWare License Purchase** project
24 over the course of 12-months ending December 31, 2025, as shown on line 14 of
25 Exhibit A-12 Schedule B5.7.7.

Line
No.

1 VMware is a virtualization and cloud computing software for IT infrastructure like
2 Vrealize operations, Vrealize automation, VMWare Hypervisor and vCenter Server
3 and vSphere Client. The Company uses these to run over 150 critical applications
4 including customer facing apps such as CR&B.

5 See Exhibit A-24 N3 Line 293 for additional project details.

6

7 Return-to-Health

8 **Q59. Can you explain in detail the Infrastructure Operations investment in the**
9 **‘Return-to-Health’ category?**

10 A59. The Company will invest \$38.4 million in the Return-to-Health category over the
11 course of 36-months ending December 31, 2025, as shown in lines 15 to 30 of the
12 Capital Expenditures Exhibit A-12 Schedule B5.7.7. The planned costs are
13 primarily across projects that are discussed further below:

14

15 **Compute and Storage Cache Refresh**

16 • The Company will invest \$0.5 million in the **Compute and Storage Cache**
17 **Refresh** project over the course of 24-months ending December 31, 2024, as shown
18 on line 15 of Exhibit A-12 Schedule B5.7.7.

19 This project includes increasing storage capacity to support on-premise
20 infrastructure and will be implemented by the IDSS team in collaboration with
21 DELL/EMC. The current storage infrastructure in use at our primary data center is
22 running at an average 80% capacity to accommodate existing and new applications
23 demands. This project will reduce system overloads and improve the efficiency of
24 application performance. A 30% increase in storage and compute will allow us to
25 accommodate an anticipated 20% increase in the application workload.

Line
No.

1 The project reflects a variance of \$0.3 million less in the 36 months ending
2 December 31, 2024, than was approved for cost recovery in U-21297. In 2023, this
3 scope was deprioritized to support the cost for the Dell Storage Agreement as
4 discussed within testimony of Server Engineering Support Services page PS-107,
5 lines 4-12. The 2023-2024 spend was approved for cost recovery in U-21297.

6

7 **Conference Room Audio Video Support**

- 8 • The Company will invest \$1.4 million in the **Conference Room Audio Video**
9 **Support** project over the course of 36-months ending December 31, 2025, and has
10 a historical spend of \$0.3 million in 2022, as shown on line 16 of Exhibit A-12
11 Schedule B5.7.7.

12 The Company intentionally does not maintain the internal specialized staffing
13 levels required to meet the growing demands (both project and operational) of
14 Endpoint Engineering Conference Room and Audio-Visual (A/V) support
15 services/functions across the enterprise. This allows the Company to flex staffing
16 models as necessary and respond timely to changing use/needs given the remote
17 work reality.

18 This project reflects a variance of \$0.3 million more than approved for cost
19 recovery in U-21297. In 2022, incremental audio video equipment failures occurred
20 requiring more equipment procurement and labor than estimated for the year. In
21 2024 and 2025, additional conference rooms have been added to the plan to meet
22 the demand of the Company. The 2022-2024 spend was approved for cost recovery
23 in U-21297.

24 See Exhibit A-24 N3 Line 299 for additional project details.

25

Line
No.

1 **Data Center Modernization and Optimization**

- 2 • The Company will invest \$3.8 million in the **Data Center Modernization and**
3 **Optimization** project over the course of 36 months ending December 31, 2025,
4 and has a historical spend of \$1.1 million in 2022, as shown on line 17 of Exhibit
5 A-12 Schedule B5.7.7.

6 Four Uninterruptible Power Supplies (UPS) that provide the necessary power
7 redundancy in our core data centers have reached or exceeded their serviceable end-
8 of-life of 20 years per the OEM. These units must be replaced to maintain the
9 security of having appropriately modulated power in the case of a data center power
10 outage. A UPS is an industry standard solution which is core to every data center
11 and ensures that power will continue to be provided to critical IT equipment while
12 the emergency generators start up and begin to provide power.

13 The Company relies on the ability of our technology to meet the computing
14 demands of daily operations. Much the same as these assets require modulated
15 power to function within specification, they also need to have the necessary
16 redundant power to function in the case of a data center outage. The replacement
17 of the UPSs provides this insurance and ensures the capability of the business
18 processing needs in the case of a data center power outage.

19 Six strings of batteries that work in conjunction with the UPSs, will also be
20 replaced. The normal lifespan of our batteries is three to five years and each one of
21 these battery strings is over five years old. The batteries will be upgraded at the
22 time of replacement to a newer technology that will double the expected lifespan
23 and reduce the annual maintenance by 50%.

24 Delaying the replacement of these end-of-life assets increases the risk of loss of
25 redundant power to the infrastructure assets that we use to host our business

Line
No.

1 applications and customer data. The 2022-2024 spend was approved for cost
2 recovery in U-21297.

3 See Exhibit A-24 N3 Line 303 for additional project details.

4

5 **Digital Worker Experience Electric EOL**

- 6 • The Company will invest \$8.3 million in **Digital Worker Experience Electric**
7 **EOL** (previously called Endpoint End of Life Electric) over the course the 36-
8 months ending December 31, 2025, and has a historical spend of \$7.9 million in
9 2022, as shown on line 18 of Exhibit A-12 Schedule B5.7.7.

10 This project was previously approved in U-21297 and reflects a variance of \$5.6
11 million more than was approved for cost recovery. This was due to the \$0.9 million
12 (20%) disallowance from the Commission in U-21297, and \$3.9 was incremental
13 spend in 2022 for the procurement of 350 mobile device terminals (MDT) to replace
14 those that had a high failure rate and were past EOL, and 336 marginal devices that
15 did not meet the hardware requirements for ADMS. Finally, incremental labor was
16 required for the deployment of these devices began in support of ADMS. The
17 majority of these MDT's are vehicle based requiring additional Docks, cabling
18 harnesses, and installation costs.

19 Annually, the Company issues, supports, and maintains over 14,000 Company-
20 owned endpoint devices (desktop computers, laptops, tablets, smart devices, and
21 ruggedized field computers) throughout the business. This annual project replaces
22 20% of these devices each year to maintain the asset refresh rates of 95% devices
23 greater than 5 years old (refer to the Table 2 below). The plan also takes into
24 consideration adding 25 units per year due to new hires and replacement of 100
25 units per year that are damaged or destroyed through normal use. To meet the
26 change in the workforce model from onsite to remote, the Company requires

Line
No.

1 replacement of onsite desktop towers with laptops as well as the additional labor
2 required to deploy the devices in a timely manner.

Endpoint Devices Replaced by Year

Device Type	Refresh Year		
	2023	2024	2025
~~Laptop~~	617	800	700
Desktop	1	100	185
Monitors	180	100	100
Tablets	25	40	28

5 See Exhibit A-24 N3 Lines 304-307 for additional project details.

End of Life Asset Replacements

- 8 • The Company will invest \$1.5 million in the **End of Life Asset Replacements**
9 project over the course of 36-months ending December 31, 2025, and has a
10 historical spend of \$6.8 million in 2022, as shown on line 19 of Exhibit A-12
11 Schedule B5.7.7.

12 The EOL Asset Replacement project will replace servers, storage, databases, and
13 operating licenses that are at end of their serviceable life which means they are no
14 longer capable of accepting operating system or security vulnerability remediation,
15 capacity has reached the upper threshold of processing ability, or the technology
16 will no longer interact with newer components within the architecture. These assets
17 located within our corporate data centers or major secondary sites are reliant upon
18 **Table 3** continuous upgrades to ensure that security, capacity, or operating parameters are
19 capable of meeting business requirements (see Table 3).

Device Lifecycle Management Standards

Line
No.

Component	Lifecycle
Servers	5 Years
Storage	3 Years
Operating Systems	Annual Upgrades
Databases	Annual Upgrades

This project reflects a variance of \$6.5 million more in the 36 months ending December 31, 2024, than approved for cost recovery in U-21297, as explained below. In 2022, \$6.1 million was required to support a 3-year license purchase for VMWare. This was critical to ensure service continuity to our customers. The 2022-2024 spend was approved for cost recovery in U-21297.

See Exhibit A-24 N3 Line 311 for additional project details.

Field Worker Device End of Life

- The Company will invest \$1.8 million in the **Field Worker Device End of Life** project over the course of 36-months ending December 31, 2025, as shown on line 20 of Exhibit A-12 Schedule B5.7.7.

This project will establish and execute the annual EOL replacement cycle for the enterprise MDT devices. Mobile Data Terminal is a computerized device used on mobile devices (devices in transit or devices that are mounted on systems that are always on the move) to communicate with a centralized control system. Mobile data terminals are equipped with technology to provided maps and information systems regarding geographic locations and other information relevant to the tasks and actions performed by the devices they are mounted on. These capabilities allow field workers to resolve customer issues and provides input to customer service representatives so they may effectively respond to customer queries.

The lifecycle of the current Mobile Data Terminal (MDT) fleet has been stretched to the point that field crew are experiencing multiple device and connectivity

Line
No.

1 failures. This impacts the crew's ability to gain insight into customer issues and
2 outages, provide updates to leadership and customer service, communicate
3 resolution and closure of customer concerns in a safe and efficient way.

4 See Exhibit A-24 N3 Lines 312-313 for additional project details.

5

6 **Load Balancer Asset Health and Re-Engineering**

- 7 • The Company will invest \$0.5 million in the **Load Balancer Asset Health and Re-**
8 **Engineering** project over the course of 12-months ending December 31, 2025, as
9 shown on line 21 of Exhibit A-12 Schedule B5.7.7.

10 This project will replace the hardware load balancers that will be deemed end of
11 life by 2025 with modern virtual load balancers. Virtual load balancers are
12 virtualized application delivery controller software that helps to distribute network
13 traffic load amongst backend servers. Virtual Load Balancers are software-based
14 load balancing solutions that help manage load effectively while still offering
15 exceptional performance and scalability. Having unsupported load balancers would
16 increase security vulnerabilities to approximately 4000 URL's required for
17 applications to function to support operations.

18 See Exhibit A-24 N3 Line 314 for additional project details.

19

20 **Microwave End of Life**

- 21 • The Company will invest \$1.2 million in the **Microwave End of Life** project over
22 the course of 36-months ending December 31, 2025, and has a historical spend of
23 \$0.5 million in 2022, as shown on line 22 of Exhibit A-12 B5.7.7.

24 This project reflects a variance of \$0.2 million more in the 36 months ending
25 December 31, 2024, than approved for cost recovery in U-21297, primarily due to

Line
No.

1 the 20% disallowance of \$146 thousand from the commission and the balance was
2 due to higher contractor cost from MCE, (Motor City Electric).

3 The Company owns and operates its own set of microwave communications
4 installations. As the network grows from business-driven requirements, the
5 Company must replace aging assets as well as add components as we strengthen,
6 tune, and optimize the system. This investment includes replacement of microwave
7 paths, enhancements to stabilize the microwave ring, and support changes
8 mandated by the FCC in deregulation of the 6 gigahertz (Ghz) frequency. These
9 efforts provide overall improvements to infrastructure redundancy, availability,
10 capability, and security. The 2022-2024 spend was approved for cost recovery in
11 U-21297.

12 See Exhibit A-24 N3 Line 318 for additional project details.

13

14 **Modernize Disaster Recovery Tools**

- 15 • The Company will invest \$0.5 million in the Modernize Disaster Recovery Tools
16 project over the course of 36-months ending December 31, 2025, as shown on line
17 23 of Exhibit A-12 Schedule B5.7.7.

18 DTE has a custom-built solution for disaster tolerance and recovery that supports
19 SAP, Maximo and AMI systems that support field operations. This legacy solution
20 was implemented in 2006. These applications and data support critical business
21 processes must be able to recover from a data center disaster (weather, water
22 damage, facility damage) or event. The existing Disaster Tolerant High
23 Availability (DTHA) solution is built on now obsolete technology and
24 infrastructure and last upgrade available in 2017.

25 This technology (DTHA Commander) has become increasingly difficult and
26 expensive to maintain due to outdated programming language maintenance and gap

Line
No.

1 in industry of skilled resources required to support it. The security risk has
2 increased as it is no longer supported by the operating system vendor. This system
3 must be modernized in order to maintain the capability to withstand and recover
4 from unplanned system failures that impact the Company's computing
5 infrastructure. This project scope will design, test, and deploy a modern disaster
6 recovery solution onto DTE's private cloud platform ensuring operational
7 reliability of core operational systems within the Company.

8 See Exhibit A-24 N3 Line 319 for additional project details.

9

10 **Network Advanced Metering Infrastructure Support**

- 11 • The Company will invest \$6.5 million in the **Network Advanced Metering**
12 **Infrastructure Support** project over the course of 36-months ending December
13 31, 2025, and has a historical spend of \$2.4 million in 2022 as shown on line 24 of
14 Exhibit A-12 Schedule B5.7.7.

15 The Network AMI Support project sustains the network and connected devices that
16 the Company uses to enhance and support the AMI mesh. This network
17 infrastructure is responsible for transporting the meter information needed to
18 accurately bill customers for service and to control/monitor the metered usage for
19 our 2.6 million electric customers. There are over 10,000 assets installed in the field
20 as of this filing. As DTE expands the AMI mesh via direction from the business,
21 the Company projects the annual cost based on previous year deployments to ensure
22 that the business priorities are met.

23 Without this investment there would have been unplanned hardware outages that
24 would adversely affect data related to customer power outages and accuracy of
25 billing. The 2022-2024 spend was approved for cost recovery in U-21297.

26 See Exhibit A-24 N3 Line 323 for additional project details.

Line
No.

1

2 **Network Data Center End of Life**

- 3 • The Company will invest \$1.9 million in the **Network Data Center End of Life**
4 Project over the course of 36-months ending December 31, 2025, and has a
5 historical spend of \$0.4 million in 2022, as shown on line 25 of Exhibit A-12
6 Schedule B5.7.7.

7 Annually key data center networking assets that have achieved end of serviceable
8 life must be replaced. The Company continually monitors the age and capability of
9 these devices and connections along with information from the OEM to identify
10 which of these assets must be replaced and estimate the costs for investments for
11 the coming year. This effort will replace data-center core switches, routers, and
12 include the installation of new components to allow the Company to increase the
13 connection bandwidth between its two data centers. Business applications with a
14 requirement of failover and backup capabilities rely on the operability of these
15 devices to ensure continuity in the event of an unplanned outage. The Company
16 continuously monitors the latest technologies available from its vendors. Through
17 this analysis determinations are made as to interoperability, capability, impact to
18 the architecture, business impact, and cost analysis. Replacing the existing core
19 switches and routers with alternative products would cost the Company \$5-\$10
20 million.

21 This project reflects a variance of \$0.4 million more in the 36 months ending
22 December 31, 2024, than approved for cost recovery in U-21297 due to a \$0.2
23 million (20%) disallowance from the MPSC in U-21297, along with an increase in
24 spend in 2023 to accommodate supply chain equipment receipt deferrals from 2022
25 into 2023. The 2022-2024 spend was approved for cost recovery in U-21297.

26 See Exhibit A-24 N3 Line 327 for additional project details.

Line
No.

1

2 **Network End of Life Electric**

- 3 • The Company will invest \$2.3 million in **the Network End of Life Electric** project
 4 over the course of 36-months ending December 31, 2025, and has a historical spend
 5 of \$0.4 million in 2022, as shown on line 26 of Exhibit A-12 Schedule B5.7.7.

6 This project is an ongoing program to replace EOL network hardware that is not
 7 physically located in either of the corporate data centers. These updated solutions
 8 will address the components that have reached their end of designed and serviceable
 9 life, as well as provide additional network expansions to meet business-partner
 10 requirements, expectations, and demand (see Table 4).

11

12

13

Table 4

Network Devices Replaced by Year

14

Year	2022	2023	2024	2025
Assets Replaced	110	50	100	100

15

16 The Network EOL – Electric project will annually fund only those devices within
 17 the purview of Infrastructure and Operations. This investment will maintain the
 18 core foundation for upcoming investments needed for new customer rates like Time
 19 of Use billing, and accounts for planned data loads as new electric-grid-control
 20 systems come online. It will further increase the size and capacity of existing
 21 equipment as key electrical-control points for required security upgrades. Examples
 22 of these enhancements are support for perimeter intrusion detection and streaming
 23 real-time video surveillance at locations that are deemed critical or high. This
 24 updated infrastructure will provide improved stability and supportability across the
 25 network. The 2022-2024 spend was approved for cost recovery in U-21297.

Line
No.

1 See Exhibit A-24 N3 Line 331 for additional project details.

2

3 **Security Infrastructure Growth and EOL**

- 4 • The Company will invest \$4.2 million in the **Security Infrastructure Growth and**
 5 **EOL** project over the course of 36-months ending December 31, 2025, and has a
 6 historic spend of \$7.4 million in 2022, as shown on line 27 of Exhibit A-12
 7 Schedule B5.7.7.

8 This ongoing program covers annual investment replacing 15% to 20% of security
 9 infrastructure equipment. These systems average a life span of five to seven years
 10 based on OEM. As reflected in Table 5 below, these systems have the following
 11 equipment replacement cycle to ensure they remain within vendor supportable life:

12

13 **Table 5 Security Asset Lifecycle**

Asset	Lifecycle
System Baselineing	4 years
Firewalls	5 years
DNS	6/7 years
Vulnerability Tool	6 years
Web Proxy	5 years
DataPower	4 years
Windows server hardware/software	5-7 years

14

15 This plan addresses annual upgrade of firmware and hardware and increasing capacity
 16 to manage growth in IT and OT environments. While the Company wants to remediate
 17 every potential cyber security and operational risk, this goal is unrealistic given the
 18 volume, variability, and constantly evolving nature of risks. To manage and prioritize

Line
No.

1 Cyber Risk Management, the Company uses a multi-layer, risk-based approach that
2 assesses risk, criticality, and controls.

3 This project reflects a variance of \$5.7 million more in the 36 months ending December
4 31, 2024, than approved for cost recovery in U-21297. In 2022, the Company required
5 the purchase of the Palo Alto license and cybersecurity specialized hardware resulting
6 in the \$6M increased spend from the amount approved in U-21297. The Company has
7 since planned for the purchase of Palo Alto licenses as a separate capital project which
8 will reoccur in 2025. The 2022-2024 spend was approved for cost recovery in U-21297.
9 See Exhibit A-24 N3 Line 335 for additional project details.

10

11 **Wide Area Network and Wireless Local Area Network Expansion**

- 12 • The Company will invest \$2.6 million in the **Wide Area Network and Wireless**
13 **Local Area Network Expansion** project over the course of 36-months ending
14 December 31, 2025, as shown on line 28 of exhibit A-12 Schedule B5.7.7.

15 This project reflects a variance of \$0.9 million less in the 34 months ending
16 December 31, 2024, than approved for cost recovery in U-21297. This is due to
17 \$0.6 million (20%) disallowance by the Commission in U-21297, along with the
18 deferral of equipment receipt planned for 2022 which could not be received until
19 2023 due to vendor supply chain issues.

20 The Wide Area Network (WAN) MPLS is the core network equipment responsible
21 for the telephony service at most of the Company's office locations. This
22 technology ensures that our communications network can support voice
23 interactions between ourselves, our customers, and other businesses. The
24 replacement of SIP Trunks is necessary to harden the ConnectUs Teams investment
25 and will allow DTE Employees to continue work activities remotely without
26 interruption. The current state of the Wireless Local Area Network (WLAN)

Line
No.

1 requires expansion to cover new locations and additional points of activity to ensure
2 connectivity for field and knowledge workers at DTE locations. The devices that
3 support the daily business operations have reached the end of their serviceable life
4 and are unable to be kept viable to meet the requirements of the business. Corporate
5 WLAN expansion is needed to support the increased number of devices and
6 network coverage. The current wireless components comprising the network at
7 many DTE locations are not optimal as wireless requirements have changed since
8 their original installation. The 2023-2024 spend was approved for cost recovery in
9 U-21297.

10 See Exhibit A-24 N3 Line 338 for additional project details.

11

12 **Virtual Desktop Infrastructure End of Life**

- 13 • The Company will invest \$1.5 million in the **Virtual Desktop Infrastructure**
14 **Asset Health** project over the course of 36-months ending December 31, 2025, as
15 shown in line 30 of Exhibit A-12 Schedule B5.7.7.

16 The current virtual desktop hardware including virtual desktops and virtual
17 application clusters is reaching end of life by the end of 2023. This hardware
18 provides secure virtual network connectivity to approximately 7000 users across
19 the enterprise and without the necessary replacement there would be loss
20 connectivity for all end users on utilizing the Virtual desktop and application
21 infrastructure which would impact their ability to perform daily operations.

22 See Exhibit A-24 N3 Lines 341- 342 for additional project details.

23

24 IT Enhancements

25 **Q60. Can you explain in detail the Infrastructure Operations investment in the IT**
26 **Enhancements category?**

Line
No.

1 A60. The Company will invest \$1.6 million in the IT Enhancement category over the
2 course of 36-months ending December 31, 2025, as shown in lines 31 to 35 of the
3 Capital Expenditures – Exhibit A-12 Schedule B5.7.7. The planned costs are
4 primarily across projects that are discussed further below:

5

6 **Network Segmentation (phase 2+) emergent extension**

- 7 • The Company will invest \$1.2 million in the **Network Segmentation (phase 2+)**
8 **emergent extension** project over the course of 36-months ending December 31,
9 2025, as shown on line 32 of Exhibit A-12 B5.7.7.

10 Cyber threats continue to rise, and it has become increasingly important to add
11 additional cybersecurity countermeasures to the Company's networks.

12 Cisco Application Centric Infrastructure (ACI) technology restricts traversing the
13 DTE network. There are multiple legacy Cisco network switches which are
14 currently end of life and are no longer compatible with current versions of the N9K
15 FX3 version of network switches and configuration of the Cisco ACI technology.
16 This has impacted the installation and use of firewalls to isolate applications
17 running on obsolete operating systems.

18 See Exhibit A-24 N3 Lines 345-347 for additional project details.

19

20 **Self-Healing Endpoint Automation**

- 21 • The Company will invest \$0.3 million in the **Self-Healing Endpoint Automation**
22 project over the course of 12-months ending December 31, 2025, as shown on line
23 33 of Exhibit A-12 Schedule B5.7.7.

24 This project will utilize Microsoft InTune, an existing platform within the IT
25 technology landscape, for endpoint (desktops, laptops, MDT, iPads, Androids,
26 etc) management of function and security requirements. Endpoint management

Line
No.

1 today is a manual process requiring labor resources to build and image endpoints,
2 ship endpoints, and manage functional requirements such as hard drive spacing,
3 CPU memory performance management.

4 Microsoft Intune will be used along with Autopilot and Microsoft PowerShell
5 scripting will automate these services. InTune will enable remote endpoint builds,
6 remote endpoint imaging and application delivery, and remote device wiping and
7 patching.

8 Autopilot will enable direct shipment of endpoints to the Company's end users.

9 And finally, PowerShell scripting will enable employees to manage endpoint
10 functional self-healing of hard drives and CPU memory performance management.

11 See Exhibit A-24 N3 Line 348 for additional project details.

12

13 **Wireless Local Area Network Expansion**

14 • The Company invested \$1.3 million in the **Wireless Local Area Network**
15 **Expansion** project over the course of 12-months ending December 31, 2022, as
16 shown line 35 of Exhibit A-12 Schedule B5.7.7.

17 This project reflects a variance of \$0.2 million more in the 36 months ending
18 December 31, 2024, than approved for cost recovery in U-21297, this is due to
19 increased demand from external project dependencies for wireless LAN
20 requirements.

21 The benefits of this investment are targeted to reduce the number of wireless
22 incidents reported by ~20% and increase employee productivity by the increased
23 wireless coverage with a targeted network utilization across the Company locations
24 at ~80%.

25 The consideration of alternative providers or asset types were rejected since they
26 would impose an undue burden due to the reconfiguration required.

Line
No.

1 The “do nothing” alternative would not allow us to meet the requirements of the
2 business, reduce connectivity availability, and delay the collaboration capabilities
3 in service and therefore was rejected.

4 See Exhibit A-24 N3 Line 351 for additional project details.

5

6 Strategic

7 **Q61. Can you explain in detail the Infrastructure Operations investment in the**
8 **Strategic category?**

9 A61. The Company will invest \$29.1 million in the Strategic category over the course of
10 36-months ending December 31, 2025, as shown in lines 36 through 47 of the
11 Capital Expenditures Exhibit A-12 Schedule B5.7.7. The planned costs are
12 primarily across projects that are discussed further below:

13

14 **ConnectUs Teams**

15 • The Company will invest \$1.0 million in the **ConnectUs Teams** project over the
16 course of 11-months ending November 30, 2023, and has a historical spend of \$1.9
17 million in 2022 as shown on line 36 of exhibit A-12 B5.7.7.

18 This is a continuation of the project the Commission approved for inclusion in rates
19 in both Case No. U-20162 and Case No. U-20561. The Company has adopted an
20 increasingly electronic collaboration method through Microsoft Teams and its
21 connected services/products, formerly referred to as Skype for Business
22 Conversion (to Teams). Ongoing investment in this conversion is the continuation
23 of a multi-year implementation of infrastructure and software updates to enhance
24 our security, simplify support efforts, drive collaboration, and enable our workforce
25 to effectively work remotely. The work in 2022 for Teams calling we successfully
26 enabled 36 sites.

Line
No.

1 This project reflects a variance of \$1.9 million more in the 36 months ending
2 December 31, 2024, than approved for cost recovery in U-21297 primarily due
3 incremental Microsoft licensing purchased to support the enterprise.

4 The benefits of this investment will be in reduced O&M cost to maintain physical
5 assets. The Company has been able to reduce teleconferencing expenses by 80%
6 (comparing 2020 actuals to 2022 actuals) to date with the rollout of Teams calling
7 capability as shown in Table 6 below.

8

Teleconferencing Actuals by Year

Spend Category	2020	2021	2022	2023
Table 6				
COM NETWORK SERVICES	159,194.15	52,355.77	36,229.55	8,988.79
TELECONFERENCING	173,595.46	37,957.32	30,416.21	0.00
Grand Total (\$)	332,789.61	90,313.09	66,645.76	8,988.79

9

10 The 2022 spend was approved for cost recovery in U-21297. See Exhibit A-24 N3
11 Line 353 or additional project details.

12

13 **Data Power Replacement**

- 14 • The Company will invest \$0.6 million in the Data Power Replacement project over
15 the course of 12-months ending December 31, 2023, as shown on line 37 of Exhibit
16 A-12 Schedule B5.7.7.

17 The Company uses DataPower to provide security services for applications that are
18 externally exposed as well as for the applications that are externally hosted. The
19 services include authentication/authorization of or the users to access applications
20 based on need, as well as provide layered protection to prevent unauthorized access.
21 It is also used as an identity provider for some of our cloud hosted applications.
22 Today, this identity provider capability resides on physical servers in our data

Line
No.

1 centers. This project adopted industry standard cloud technology aligning with the
2 Smart Cloud guidance and security best practices.

3 See Exhibit A-24 N3 Line 354 for additional project details.

4

5 **Data Power Replacement Phase 2**

- 6 • The Company will invest \$0.7 million in the Data Power Replacement Phase 2
7 project over the course of 12-months ending December 31, 2024, as shown on line
8 38 of Exhibit A-12 Schedule B5.7.7.

9 The DMZ DataPower Gateway capability resides on physical servers in our data
10 centers and provides security services for applications that are externally exposed.
11 The services include authentication/authorization for users to access applications
12 based on need, layered protection to prevent unauthorized access, and provision of
13 identity for some cloud hosted applications. This project will move current
14 functionality away from physical data centers and into the cloud— specifically
15 Microsoft application proxy in the Azure cloud. The project will replace Data
16 Power identity management capabilities for the targeted applications, with an
17 optimal solution including reverse proxy provision as well as identity provider
18 capabilities.

19 As a foundational capability all DTE business unit applications will utilize the new
20 cloud-based application gateway platform to provide secure access to employees
21 and customers. And finally provide the increased application capacity to be hosted
22 by Cloud Application Gateways, since the current systems are at capacity and
23 unable to support more applications.

24 See Exhibit A-24 N3 Line 355 for additional project details.

25

Line
No.

1 **Digital Infrastructure and Services**

- 2 • The Company invested \$6.4 million in the **Digital Infrastructure and Services** in
- 3 the historical period ending December 31, 2022, as shown on line 39 of Exhibit A-
- 4 12 Schedule B5.7.7. This project reflects a variance of \$2.2M less than approved
- 5 for cost recovery in U-21297. The remaining \$2.2 million is included in the spend
- 6 for the Tree Trim Risk Prioritization Model project shown on line 24 of the Exhibit
- 7 A-12 Schedule 5.4. The Company is not seeking any additional recovery for this IT
- 8 project in the current case. Please refer to the testimony of Witness Steudle for the
- 9 detailed business benefits. See Exhibit A-24 N3 Line 356 for additional project
- 10 details.

11

12 **DTE Private Cloud Infrastructure as a Service**

- 13 • The Company will invest \$0.6 million in the **DTE Private Cloud Infrastructure**
- 14 **as a Service** project over the course of 24-months ending December 31, 2024, and
- 15 has a historical spend of \$0.4 million ending December 31, 2022, as shown on line
- 16 40 of Exhibit A-12 Schedule B5.7.75.

17 DTE Cloud infrastructure management and provisioning currently requires 3 full

18 time resources annually to manage. The implementation of various cloud

19 management tools and automating processes will reduce the manual processing,

20 reduce provisioning and deployment cycle time, enable the application teams to

21 estimate infrastructure costs directly, reduce operational costs due to virtualization,

22 and allow tight integration with the IT work management system (ServiceNow).

23 As of October 2022, DTE has approximately 44 Windows 2003 servers, 97

24 Windows 2008 servers, and 703 Windows 2012 servers that are out of support or

25 soon to be out of support and will have the opportunity to be migrated to the Azure

Line
No.

1 IaaS private or public Cloud. Beginning in 2023, the project started application
2 deployment and migrate workloads onto the infrastructure.

3 This project reflects a variance of \$0.5 million less in the 36 months ending
4 December 31, 2024 than approved for cost recovery in U-21297. In 2022, the
5 Company spent \$0.4 million less than approved for cost recovery in U-21297, this
6 was primarily a result extended Microsoft Licensing negotiations that delayed
7 purchasing all the 2022 planned licenses. Final negotiations resulted in a savings
8 to the required spend of \$0.4 million due to bundling multiple licenses into one
9 agreement. The 2022-2023 spend was approved for cost recovery in U-21297.

10

11 **Endpoint Operating System and Hardware Upgrade**

- 12 • The Company will invest \$6.9 million in the **Endpoint Operating System and**
13 **Hardware Upgrade** project over the course of 24-months ending December 31,
14 2025, as shown on line 41 of Exhibit A-12 Schedule B5.7.7.

15 This project is planned for the necessary upgrade of 9,700 machines from Windows
16 10 to Windows 11 in 2024, as well as replacement of 1,000 machines during that
17 timeframe¹³, with a total of 15,000 devices being upgraded at project completion in
18 2026.

19 Windows 10 extended support includes updating the operating system and this
20 support officially ends October 2025. Updating endpoint operating systems will
21 reduce DTE's exposure to operating-system-based vulnerabilities within the DTE
22 network. This three-year project further supports the strategic direction to upgrade
23 to Windows 11 for the entire organization across roughly 10,000 devices.

¹³ DTE endpoint devices that have antiquated technology and operating systems will no longer be supported through Microsoft's standard support process, rendering the user unable to perform job responsibilities.

Line
No.

1 This project reflects a variance of \$0.6 million less in the 36 months ending
2 December 31, 2024 than approved for cost recovery in U-21297. This is due to the
3 deferment of purchase and installation of 425 devices to 2025. This deferment will
4 free up the resources to work on higher priority projects to sustain operational
5 reliability. The 2024 spend was approved for cost recovery in U-21297.

6 See Exhibit A-24 N3 Line 360 for additional project details.

7

8 **Enterprise Monitoring Strategy Implementation**

- 9 • The Company invested \$5.0 million in the Enterprise Monitoring Strategy
10 Implementation project during the 24 months ending December 31, 2023, as shown
11 on line 42 of Exhibit A-12 Schedule B5.7.7.

12 This project reflects a variance of \$4.5 million more in 2022 than approved for cost
13 recovery in U-21297 due to the pull ahead of Dynatrace monitoring software
14 license purchase by one month (originally planned in January of 2023 but
15 contracted in December of 2022 to avoid possible service interruption and
16 accommodate growth in the extent of our enterprise monitoring deployment.

17 The 2022-2023 spend was approved for cost recovery in U-21297.

18

19 **External Secure File Transfer Replacement**

- 20 • The Company invested \$0.4 million in the **External Secure File Transfer**
21 **Replacement** project during the 36-month ending December 31, 2025, as shown
22 on line 43 of Exhibit A-12 Schedule B5.7.7.

23 This project reflects a variance of \$0.2 million less in the 36 months ending
24 December 31, 2024, than approved for cost recovery in U-21297. This was due to
25 scope reductions due to company's financial constraints in 2023.

26

Line
No.

1 **Firewall Threat Protection**

- 2 • The Company will invest \$2.1 million in the **Firewall Threat Protection** project
3 over the course of 36-months ending December 31, 2025, as shown on line 44 of
4 Exhibit A-12 Schedule B5.7.7. This project reflects a variance of \$1.8 million less
5 than approved for cost recovery in U-21297. The Palo Alto License agreement
6 purchase in 2022 provided additional features for Threat Protection, this reduced
7 the estimated cost for procurement and deploying additional hardware planned for
8 this project.

9 External and internal threats to DTE cyber security continue to increase and evolve
10 for both IT and OT/Control networks. This will require the Company to build
11 additional protection, detection, and response capabilities to protect DTE's assets.
12 To achieve this, there is a strategic need to deploy firewalls that can provide added
13 capacity as well as advanced capabilities for real time threat protection. Some of
14 the business areas where this is anticipated include Customer Payments, Energy
15 Supply control networks, AMI, Gas and Electric SCADA, and substation networks.
16 The solution is a centralized repository to retain threat intel received from vendors,
17 government agencies (DHS, DOE, FBI, etc.), Information Sharing and Analysis
18 Centers (E-ISAC, DNG-ISAC), peer companies, and from DTE's internal sources.
19 The 2023-2024 spend was approved for cost recovery in U-21297.

20

21 **Mobile Device Management (MDM)**

- 22 • The Company will invest \$0.8 million in the **Mobile Device Management (MDM)**
23 project over the course of 24-months ending December 31, 2024, as shown on line
24 45 of Exhibit A-12 Schedule B5.7.7.
25 This project reflects a variance of \$0.2 million more than approved for cost
26 recovery in U-21297 due to combining scope from Enterprise Mobility

Line
No.

1 Management demand into the Mobile Device Management demand and adding
2 onsite resources to support field crew with their assigned device migration to DTE's
3 new Mobile Device Management platform from Microsoft at various DTE
4 facilities. During the migration, extended support is required as part of the hyper
5 care resulting in the additional spend. The 2023-2024 spend was approved for cost
6 recovery in U-21297.

7 See Exhibit A-24 N3 Line 368 for additional project details.

8

9 **Storm Cloud**

- 10 • The Company will invest \$16.0 million in **Storm Cloud** project over the course of
11 36-months ending December 31, 2025, as shown on line 47 of Exhibit A-12
12 Schedule B5.7.7.

13 DTE has suffered several technology related challenges during storms which drive
14 costs to restore and impact customer satisfaction. System resiliency for our cloud-
15 based applications has become an issue impacting our customers. Over the last few
16 years DTE has faced multiple storms where application resiliency issues hindered
17 the restoration effort and impacted customer satisfaction. In 2022 and 2023, DTE
18 weathered 6 catastrophic storms, impacting 2.1M customers. At several points
19 during the storms DTE's IT infrastructure experienced performance degradation in
20 applications critical in servicing our customers and aiding restoration efforts.
21 Customers were unable to review or report outages in our mobile apps. Tools used
22 in restoration efforts were not functioning properly, requiring field workers to use
23 manual alternatives, increasing recover times. Patterns emerged around overloaded
24 IT systems and failing integrations between apps, many of which are housed in the
25 Azure Cloud. The objective of this project is to "meaningfully move the needle" on
26 two aspects of how IT can improve its performance and hence better support DTE

Line
No.

1 during its storm efforts. This will also establish an automated scalability without
2 manual intervention. The overall impact can be measured in terms of operational
3 reliability (and hence reduced downtime for crews when system outages happen)
4 as well as improved customer satisfaction from an improved ability to serve
5 customers. During catastrophic storms in 2022 and 2023, nine IT infrastructure
6 outages affecting an average of 270k customers each, directly related to overloaded
7 applications occurred on internal and customer facing applications. Each outage
8 saw degraded or unavailable applications and services for several hours during
9 critical periods, affecting hundreds of internal users dedicated to restoration efforts
10 and thousands of customers using the tools to communicate and manage their
11 outage.

12 This project is supporting the Company's storm response investments discussed in
13 Company Witness Hill's testimony and the customer interaction improvements as
14 discussed in Witness Hatsios' testimony.

15 See Exhibit A-24 N3 Lines 371-372 for additional project details.

16

17 **Enterprise Data Analytics**

18 **Q62. What is the Enterprise Data and Analytics (EDA) Portfolio?**

19 A62. The Company continues to build a cloud-based and on-premise data platform to
20 enable analytics to drive business value. This requires a data platform for data
21 storage and processing along with software to manage the data and usage. To
22 support our data users, the Company created a team to enable the infrastructure,
23 build integrations to source systems, and subsequently organize, describe, and
24 document the data available on the platform. EDA's mission is to dependably
25 deliver timely, secure, high-quality data to business partners throughout DTE.

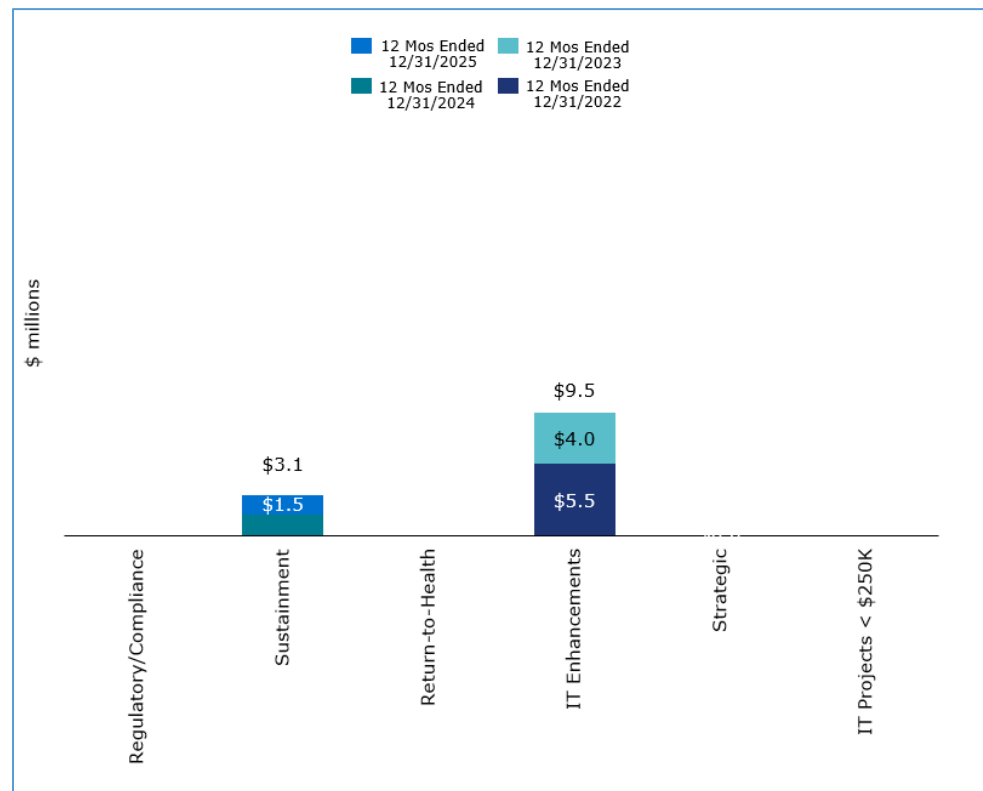
Line
No.

1

2 **Q63. What are the projected costs for investments in the Enterprise Data &**
 3 **Analytics Portfolio?**

4 A63. As reflected on line 9 of Exhibit A-12 Schedule B5.7, page 1, capital expenditures
 5 for Enterprise Data & Analytics total \$5.5 million for the historical test year ended
 6 December 31, 2021, \$5.6 million in the bridge period (for the 24 months ending
 7 December 31, 2024), and \$1.5 million for the projected test period ending
 8 December 31, 2025. The synopses below in Figure 14 provide the total spend for
 9 each line item the Company requests in this rate case and the details regarding
 10 breakout by historical period, projected bridge period, and projected test period, are
 11 laid out in Exhibit A-12 Schedule B5.7.8, in columns d, g, and h.

12 **Figure 14 Enterprise Data and Analytics – IT Investment**
 13



14

Line
No.

1 Sustainment

2 **Q64. Can you describe the investment in Enterprise Data Analytics in the IT**
3 **Sustainment category?**

4 **Enterprise Data Platform Application Health**

5 A64. Yes, the Company will invest \$3.1 million in the **Enterprise Data Platform**
6 **Application Health** project over the course of 36-months ending December 31,
7 2025, as shown on line 1 of Exhibit A-12 Schedule B5.7.8. This project reflects a
8 variance of \$1.1 million less than what was approved for cost recovery in U-21297.
9 These actual charges for the software licenses and services were accrued and
10 charged to the Advance and Enhance the Data Platform project listed below.
11 The Enterprise Data Platform Application Health project is primarily to secure 3-
12 year commitments for licenses and Azure services which allows for reduced costs
13 over the pay-as-you-go pricing. On average, the Company will save 60% by
14 reserving the use of Azure assets for a three-year period. As the cloud-based data
15 platform grows we can add additional reservations each year to take advantage of
16 more savings.
17 See Exhibit A-24 N3 Lines 373-374 for additional project details.

18

19 IT Enhancements

20 **Q65. Can you describe the investment in Enterprise Data Analytics in the IT**
21 **Enhancements category?**

22 **Advance and Enhance the Enterprise Data Platform**

23 A65. The Company invested \$4.0 million in the **Advance and Enhance the Enterprise**
24 **Data Platform** project over the course of 12-months ending December 31, 2023,
25 and has a historical spend of \$5.5 million in 2022, as shown on line 2 of exhibit A-
26 12 Schedule B5.7.8.

Line
No.

1 DTE's cloud-based data platform continued to grow in its fourth full year in
2 operation.

3 This project reflects a variance of \$7.5 million more in the 24 months ending
4 December 31, 2024, than approved for cost recovery in U-21297.

5 In 2022, this project incurred the \$3.5 million related to Enterprise Data Platform
6 Application Health licenses (Alteryx, VM Reservations) and services renewals and
7 supporting labor.

8 In 2023, which was not included in U-21297, this project added the capability to
9 bring near real-time data to support both operational and historical analytics use
10 cases (projects CODS and ADMS). Additionally, this project developed and
11 implemented a data catalog and data validation capability. These solutions and
12 additional capabilities will enable quicker response time to customer queries,
13 improved decision making, and increased satisfaction. Additionally, EDA was
14 responsible for the 2023 Azure cost for all the business units using Azure Cloud.

15 See Exhibit A-24 N3 Lines 375-376 for additional project details.

16

17 **Innovations**

18 **Q66. Can you describe the Innovations Portfolio?**

19 A66. To address customer and business challenges that cannot be solved with traditional
20 approaches, DTE applies innovation to deliver rapid value with shorter
21 development cycles and time to value. We have proven the ability to boost
22 reliability by expanding how DTE services and maintains the Company's IT assets
23 and accelerate access to decision-making tools for customer and employee use.
24 Further value is found in gaining new insights by thinking differently about
25 pressing business challenges.

Line
No.

1

2 **Q67. Can you summarize the Innovation investments?**

3 A67. The Company seeks recovery of its \$2.8 million spend in Innovation investments
4 over the course of 12-months ending December 31, 2022, as shown in line 1 of the
5 Capital Expenditures - Exhibit A-12 Schedule B5.7.9.

6

7 **Q68. Can you provide additional detail for the Innovation project?**

8 A68. Yes. The DTE Applied Innovation Team provides both capability and capacity
9 from a team comprised of in-house DTE leaders and subject matter experts, and
10 external consultants with key technology, entrepreneurial, innovation management,
11 and communications expertise. With this unique capability, the team can staff key
12 projects that DTE needs to work on, but has not yet defined, and is able to rapidly
13 respond to new business challenges identified and prioritized by executives.
14 Innovation is a support function for the entire organization and does not introduce
15 changes to core systems of record or assets. The management of assets live within
16 the business and are not owned by the innovation team.

17 The following solutions were developed through the Applied Innovation Project
18 and were in direct support of the Company's strategic priorities in 2022:

19 • **Supervisor Super Dashboard (Crew Tool Use Visualization)**

20 Historically, over 100 Distribution Operation Business Unit's supervisors and
21 managers utilized several web pages/locations to see compliance-related and safety
22 performance data of more than 2000 field crew members. This includes pre-job
23 brief completion data, vehicle idling, driving events and due dates for required
24 training and equipment expiration. This data is all housed in various disparate
25 databases (source systems) and accomplished through complex integrations and

Line
No.

1 security access passing. Innovation performed a “Go and See” to evaluate the time
2 needed to complete this daily task by observing a sample set of 12 supervisors and
3 found that the task required an hour to complete per supervisor. The solution
4 created by DTE Innovation via PowerBI allowed these data points to be brought
5 into a single page dashboard for safety, dependability, efficiency, and employee
6 engagement. Data included focused on safety and compliance - driving data, safety
7 procedure completeness and more.

8 As a result, the affected DO leadership pool productivity improves by
9 approximately 83 hours daily by ability to view and process the same data from a
10 single application page in 10 minutes or less. This allows them to see all the
11 compliance data they use to plan their day/week and where field observations may
12 help improve their team’s performance.

13 • **DO - CBC-8000 Automated Service Now Tickets from Maximo**

14 Historically, the process to connect DO Work Management and IT Work
15 Management systems to enable CBC-8000 installations was done manually. DO
16 engineering utilizes Maximo for issuing work orders for the installation of capacity
17 controls by region. This work requires IT network engineering task to be generated
18 from ServiceNow.

19 The Innovation process was designed to improve the CBC-8000 installation by
20 automating ServiceNow tickets from Maximo via an Application Programming
21 Interface. There are 3000-5000 CBC-8000 devices expected to be deployed and all
22 deployments will utilize this newly developed efficiency and quality measure. The
23 new process integrates Maximo work orders into ServiceNow IT tickets allowing
24 the two systems to communicate. When a workorder is created in Maximo, a

Line
No.

1 ServiceNow request is triggered, and updates are communicated between the two
2 systems.

3 The new process can be utilized for any small or large-scale SCADA Devices
4 deployment in the future which represents more than 3000 devices annually that
5 will utilize this newly developed efficiency and quality measure. Considering an
6 example of 3000 devices, approximately 15 minutes per request saves 45,000
7 minutes (750 hours). This also saves 10% manual entry errors, preventing 300
8 errors for 3000 devices. This solution aligns with DTE's service keys by increasing
9 efficiency and dependability, due to removal of human error and decreasing the
10 time it takes to manually enter ServiceNow tickets from Maximo.

11 See Exhibit A-24 N3 Line 377 for additional project details.

12

13 **Projects < \$250K**

14 **Q69. What is included in the "Projects less than \$250,000" category?**

15 A69. Workpaper titled "IT Projects <\$250K", shows spend for projects in IT with
16 estimated spend less than \$0.25 million in the projected bridge and test periods. The
17 investment in of these projects occurred in 2022, and we have implemented the
18 projects. These projects span the portfolios and are necessary investments to
19 collectively support DTE.

20

21 **Part IV – Historical Spend Variance**

22 **2022 Spend Variance**

23 **Q70. How much did the Company spend in 2022 on total IT capital projects**
24 **compared to what the Commission authorized for inclusion in rates in Case**
25 **No. U-21297?**

Line
No.

1 A70. The Company spent \$224.3 million of capital on IT projects in 2022 compared to
2 the \$165.0 million approved by the Commission in Case No U-21297, as shown in
3 line 18 of Exhibit A-24 Schedule N2, which is \$59.3 million more than was
4 authorized for inclusion in rates.

5
6 **Q71. What were the reasons between the 2022 actual capital spend versus the spend**
7 **the Commission authorized for inclusion in rates in Case No. U-21297 capital**
8 **spend?**

9 A71. Exhibit A-24, Schedule N2, labeled as 2022 Historical Spend Variance Recovery,
10 shows the comparison for projects greater than \$0.5 million with a variance
11 exceeding 20% and where additional recovery is being sought. The variance in
12 these projects is discussed in the corresponding project prose in the sections above
13 as referenced in Table 7.

Table 7

Variance Testimony Reference by Project

Description	Portfolio	Variance Testimony Reference
Production Growth	Plant and Field	PS-67-68
Maximo Platform Program	Plant and Field	PS-73-74
Automated Provisioning	Information Protection Security	PS-91
Ransomware Protection	Information Protection Security	PS-95
Digital Worker Experience Electric EOL	Infrastructure Operations	PS-110 –111
End of Life Asset Replacements	Infrastructure Operations	PS-112
Security Infrastructure Growth and EOL	Infrastructure Operations	PS-118-119
Enterprise Monitoring Strategy Implementation	Infrastructure Operations	PS-129
Advance and Enhance the Enterprise Data Platform	Enterprise Data Analytics	PS-134 -135

Line
No.

1

2

For the remaining variance recovery, please refer to Company Witness Hatsios'

3

testimony 2022 Historical Project Spend Variance.

4

5

Other Variance

6

Q72. Were there any other projects that had variances that you have not yet discussed?

7

8

A72. Yes. There are eight projects listed below that were not completed in 2022, 2023

9

nor are planned to be completed in 2024 as previously approved and included in

10

rates in Case No. U-21297.

11

- Environmental Air Regulation Management: This project is currently being rescheduled and upon approval of reschedule the Company will submit plan in future rate case.

12

13

14

15

- Business Continuity Plan Automation: This project has been rescheduled to 2026.

16

17

- Time Entry: This project is currently being rescheduled and upon approval of reschedule the Company will submit plan in future rate case.

18

19

20

- Tool and Inventory: This project is currently being rescheduled and upon approval of reschedule the Company will submit plan in future rate case.

21

22

23

- Cloud Insight: This project has been deferred until DTE's annual spend/usage on cloud infrastructure are significantly large enough to benefit from potential cost savings which can be identified by deploying the Cloud Insight's demand.

24

25

Line
No.

1

2 • Cyber Security for OT and ICS: This project shall be deferred to complete the OT
3 and ICS Cyber Security Assessment and developed specific recommendations to
4 be implemented in order to meet security requirements and risks identified by the
5 assessment/
6

7 • FWWW IPS: This project is no longer being pursued because DTE moved
8 employees to remote work during Covid, basically achieving the benefits which
9 were targeted through the Future of Where We Work.
10

11 • Vulnerability Managements tools for key systems: This project was originally a
12 separate initiative to address a number of IT systems and applications vulnerability
13 risk. After further review of the demand objectives and requirements, it was
14 determined that vulnerability management requirements in asset specific projects
15 would be incorporated where required.
16

17 **Q73. Does this complete your direct testimony?**

18 A73. Yes, it does.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-21534

QUALIFICATIONS

AND

REVISED DIRECT TESTIMONY

OF

AARON WILLIS

DTE ELECTRIC COMPANY
QUALIFICATIONS AND REVISED DIRECT TESTIMONY OF AARON WILLIS

Line
No.

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

2 A1. My name is Aaron Willis (he/him/his). My business address is One Energy Plaza,
3 Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC,
4 a subsidiary of DTE Energy Company as Manager, Regulatory Economics.

5

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

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

8

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

10 A3. I received a Bachelor of Arts in Political Science from the University of Michigan,
11 a Master's in Environmental Management from the Yale School of Forestry and
12 Environmental Studies, and a Master's in Business Administration from the
13 University of Maryland.

14

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

16 A4. In 2009, I was employed by the US Army Corps of Engineers, Institute for Water
17 Resources as Social Scientist. In this role I supported enforcement of the Clean
18 Water Act and engagement with domestic and international partners on a variety of
19 water resources issues. In 2015, I was employed by Booz Allen Hamilton in their
20 energy practice, providing support to commercial and federal clients on a variety
21 of energy matters including market strategies, project development, and new energy
22 technologies. In 2017, I began my employment with DTE Energy as an Associate
23 in Corporate Strategy. In this role I supported key operational and strategic work
24 across the Company. I was promoted to Senior Associate in 2019 and transitioned
25 to Corporate Development, where I supported the Company's financial strategy. In

Line
No.

1 2020, I accepted a position in Regulatory Affairs supporting the Company's state
2 regulatory strategy and engagement with the Michigan Public Service Commission
3 (MPSC or Commission), MPSC Staff, and Michigan energy stakeholders. In 2021,
4 I was promoted to my current position of Manager, Regulatory Economics.

5
6 **Q5. What are your current duties and responsibilities?**

7 A5. My responsibilities include the management of regulatory activities relative to DTE
8 Electric's rate strategy, pricing, and load research.

9
10 **Q6. Have you previously sponsored testimony before the Michigan Public Service**
11 **Commission?**

12 A6. Yes. I have sponsored testimony in the following cases:

- 13 • U-21163 XL High Load Factor Rate
- 14 • U-20836 DTE Electric 2022 General Rate Case
- 15 • U-21193 DTE Electric 2022 Integrated Resource Plan
- 16 • U-21306 Rider No. 16 Transition
- 17 • U-21338 DTE Electric 2023 Securitization
- 18 • U-21297 DTE Electric 2023 General Rate Case
- 19 • U-18091 DTE Electric 2024 PURPA Case

Line
No.

1 **Purpose of Testimony**

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

3 A7. The purpose of my testimony is to address five topics as outlined below: Forecast
4 Allocation Schedules, Power Supply Costs, Rate Design, Investment Recovery
5 Mechanism (IRM) Surcharge Design, and Other Tariff Changes.

6 • **Forecast Allocation Schedules:** Support the allocation schedules and
7 methodology utilized by the Company for the 12-month period ending
8 December 31, 2025; support allocation schedules for the EV rate design cost of
9 service and rate design.

10 • **Power Supply Costs and Nuclear Surcharge:** Support total power supply
11 costs for the 12-month period ending December 31, 2025, and the Nuclear
12 Surcharge.

13 ○ Power supply costs include the projected base transmission expense, and
14 base fuel and purchased power expense necessary for the sales forecast.
15 While maintaining the current Power Supply Cost Recovery (PSCR) base
16 of 31.26 mills per kilowatt hour at the generation level, I am proposing to
17 update the loss factor to 7.69%, which will result in a PSCR base of 33.66
18 mills per kilowatt hour at the sales level to facilitate recovery of the
19 projected costs. The method is consistent with prior Commission Orders,
20 including in the Company's most recent general rate case, Case No. U-
21 21297.

22 ○ Nuclear surcharge is designed to collect the Proposed Nuclear Surcharge
23 Revenue

24 • **Rate Design:** Support the proposed rate design and language modifications for
25 the Company's rate schedules:

Line
No.

- 1 ○ *Residential:* (1) The development of capacity and non-capacity charges for
- 2 each residential rate schedule based on the cost of service supported by
- 3 Company Witness Maroun; (2) design of variable distribution rates for all
- 4 residential secondary rate schedules; (3) proposed transition of customers
- 5 on Rate Schedule D1.6 to Rate Schedule D1.11, the applicability of Low
- 6 Income Assistance credits to all residential whole home, base rates, and the
- 7 closure of Rate Schedule D1.6
- 8 ○ *Commercial secondary:* (1) The development of capacity and non-capacity
- 9 charges for each commercial secondary rate schedule based on the cost of
- 10 service supported by Company Witness Maroun; (2) design of distribution
- 11 rates for all commercial secondary rate schedules; (3) proposed design for
- 12 an optional, commercial secondary time of use rate pursuant to the
- 13 Commission's December 1, 2023, Order in Case No. U-21297
- 14 ○ *Primary:* (1) The development of capacity and non-capacity charges for
- 15 each primary rate schedule based on the cost of service supported by
- 16 Company Witness Maroun; (2) design of distribution rates for all primary
- 17 rate schedules; (3) development of power supply rates for Rate Schedule
- 18 D13 (4) proposed design for an optional, primary time of use rate pursuant
- 19 to the Commission's December 1, 2023, Order in Case No. U-21297
- 20 ○ *Other:* (1) Proposed Rider 18 outflow credits; (2) Proposed determinants
- 21 and rates for a DC Fast Charging rate schedule pursuant to the
- 22 Commission's December 1, 2023, Order in Case No. U-21297
- 23 ● **IRM Surcharge Design:** Support pricing of the 2026 and 2027 IRM surcharge
- 24 allocated by Company Witness Maroun.

Line
No.

- 1 • **Other Tariff Changes:** Propose changes to (1) CIAC waivers for Charging
2 Forward in C6.1(16), (2) update line extension costs in Section C6 pursuant to
3 the final Order in Case No. U-21297

4
5 **Q8. Are you sponsoring any exhibits in this proceeding?**

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

7	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
8	A-5	E2	Cost of Service Allocation Methodology Diagram
9	A-5	E3	Allocation Schedule Description
10	A-13	C4	Calculation of Power Supply Expenses
11	A-13	C4.1	Five Year Average Loss Factor
12	A-16	F2	Summary Present and Proposed Revenues by Rate
13			Schedule – 12 months ending December 31, 2025
14	A-16	F3 <u>Revised</u> ¹	Present and Proposed Revenues by Rate Schedule –
15			12 months ending December 31, 2025
16	A-16	F4	Comparison of Present and Proposed Monthly Bills
17			– 12 months ending December 31, 2025
18	A-16	F5	Calculation of Voltage Level Distribution Charges
19	A-16	F6	Calculation of Nuclear Surcharge
20	A-16	F7	Calculation of Rider 18 Outflow Credits
21	A-16	F8	Proposed Tariff Sheets
22	A-16	F9 <u>Revised</u>	DCFC Rate Design
23	A-17	G1.1	Forecast Energy Allocation Schedules – 12 months
24			ending December 31, 2025

¹ Revision pertains to Pg 22 (Proposed Rate Schedule D3.11)

Line
No.

1	A-17	G1.2	Demand and Energy Allocation Percentages by Rate
2			Class
3	A-17	G1.3	Forecast Energy Allocation Schedules – 12 months
4			ending December 31, 2025 – DCFC Study
5	A-17	G1.4	Demand and Energy Allocation Percentages by Rate
6			Class – DCFC Study
7	A-33	X7	IRM Surcharge Design

8

9 With respect to Exhibit A-16, Schedule F3 Revised, I am sponsoring pages 1-46,
10 and Company Witness Bellini is sponsoring the remaining sheets contained in the
11 exhibit.

12

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

14 A9. Yes, they were.

15

16 **Allocation Schedules**

17

18 **Q10. Are there any technical terms used in your allocations testimony that may**
19 **require explanation?**

20 A10. Yes. To aid in understanding and to avoid confusion, I am defining the following
21 terms that I use throughout my testimony:

22 ▪ Customer Class or Class of Service: A set of customers with similar
23 characteristics who have been grouped for the purpose of setting an
24 applicable rate for electric service.

Line
No.

- 1 ▪ Total System Analysis (TSA): The study of all customer classes that
- 2 identifies the hourly demand values for all hours of the year. This is the
- 3 foundation of allocation schedules.
- 4 ▪ Energy: The total kilowatt-hours (kWh) or megawatt-hours (MWh)
- 5 supplied to or used by an individual customer or customer class.
- 6 ▪ Demand: The rate at which electric energy is used at a given instant or
- 7 averaged over a designated time interval. Typically, demand is expressed in
- 8 kilowatts (kW) or megawatts (MW).
- 9 ▪ Service Area System Peak Demand: The highest hourly demand for all
- 10 customers (full service and choice) served on the DTE Electric distribution
- 11 system within a specific period (day, month, year, etc.). Service Area
- 12 System Peak Demand is commonly referred to as the ‘system peak.’
- 13 ▪ Bundled Peak Demand: The highest hourly demand for all full service
- 14 customers served by DTE Electric’s production system within a specific
- 15 period (day, month, year, etc.). Bundled Peak Demand is commonly
- 16 referred to as ‘bundled peak.’
- 17 ▪ Coincident Peak Demand (CP): The demand of any customer class within a
- 18 specific period (day, month, year, etc.) that occurs at the same time as the
- 19 system peak or the bundled peak demand for the same period.
- 20 ▪ 12CP: The demand value derived by averaging the actual demand values
- 21 registered on the monthly system or bundled peak hours for January through
- 22 December for each customer class.
- 23 ▪ 4CP: The demand value derived by averaging the actual demand values
- 24 registered on the monthly bundled peak hours for June through September
- 25 for each customer class.

Line
No.

- 1 ▪ Non-Coincident Peak Demand: The maximum demand of any customer
- 2 class within a specific period but not necessarily occurring at the time of the
- 3 system peak demand for that period.
- 4 ▪ Losses: A term used to define the difference between the electrical energy
- 5 delivered to a customer (or a given point on the electrical distribution
- 6 system) and the amount of electrical energy that must be generated at the
- 7 power plant to serve that customer. In other words, losses refer to the
- 8 difference in the amount of power generated from the power plant and the
- 9 point of delivery.
- 10 ▪ Load Factor: The ratio, in percent, of the total energy over a designated
- 11 period of time to the maximum hourly demand (bundled or system)
- 12 occurring in that period. Load factor is calculated by the formula:
- 13
$$LF (\%) = (\text{Total Energy} / (\text{Peak Demand} * \text{No. of Hours})) * 100$$
- 14 ▪ Customer-Owned: Industrial customers that use customer owned
- 15 substations.
- 16 ▪ DTE-Owned: Industrial customers that use DTE Electric single customer or
- 17 joint-use general distribution substations.
- 18 ▪ Transmission Voltage Level: Served directly from the transmission system
- 19 at 120 kV or above, or from the transmission system through a DTE-owned
- 20 substation dedicated or primarily providing service to the customer and
- 21 located on or immediately adjacent to the customer's premises.
- 22 ▪ Sub-transmission Voltage Level: Served directly from the sub-transmission
- 23 system at voltages from 24 kV to 41.6 kV or from the sub-transmission
- 24 system through a DTE-owned substation dedicated or primarily providing

Line
No.

1 service to the customer and located on or immediately adjacent to the
2 customer's premises.

3 ▪ Primary Voltage Level: Served directly from the primary distribution
4 system at a nominal voltage between 4.8 kV and 13.2 kV who does not
5 qualify as either a transmission voltage customer or a sub-transmission
6 voltage customer.

7 ▪ Secondary Service: Served directly from the secondary distribution system
8 at a nominal voltage less than or equal to 4.8 kV and who does not qualify
9 as either a transmission voltage customer, sub-transmission voltage
10 customer or a primary voltage customer.

11

12 **Q11. What are the data sources for the allocation schedules?**

13 A11. The forecasted test year allocation schedules are based on 2022 customer class sales
14 data obtained from the 2022 Total System Analysis (TSA). The forecast allocation
15 schedules are based on the energy sales forecast for the residential, commercial,
16 and industrial classes supported by Company Witness Leuker, the street lighting
17 and traffic signals sales forecast supported by Company Witness Bellini, and the
18 forecast billing determinants supported in my exhibits. These sales levels are shown
19 with losses on Exhibit A-17, Schedule G1.1.

20

21 **Q12. What is the purpose of the allocation schedules you have developed?**

22 A12. Allocation schedules are developed using customer class sales, data from Advanced
23 Metering Infrastructure (AMI), and quantitative methods to determine the extent
24 (expressed as a percentage) that each customer class uses the various portions of
25 the electrical system. In this case, the customer class usage percentages determined

Line
No.

1 in the allocation schedules are one of the inputs used by Company Witness Maroun
2 to determine customer class cost responsibility. Because all customer classes do not
3 utilize the full distribution system to take delivery of electrical service, the
4 allocation schedules are developed to assign only the portions of the system used
5 by each customer class. Exhibit A-5, Schedule E2, is a diagram which reflects the
6 applicability of allocation schedules to customer class.

7

8 **Q13. How did you develop the allocation schedules?**

9 A13. There are 13 forecast allocation schedules that I developed for use in cost-of-service
10 studies (see Exhibit A-5, Schedule E3 for a description of each schedule). Each
11 schedule was developed to allocate to each customer class's utilization of a
12 particular part of the electrical system, which is the industry standard practice for
13 developing allocation schedules. Schedule 100, shown in Exhibit A-17, Schedule
14 G1.2, is based on the class's forecasted energy consumption. and the remaining 12
15 allocation schedules described in Exhibit A-5, Schedule E3, are based on the
16 forecasted demand that a customer class places on the various portions of the
17 electrical system. The allocation schedule numbers and the associated portion of
18 the electrical system they represent are shown schematically on Exhibit A-5,
19 Schedule E2.

20

21 **Q14. Why does the measurement basis differ for each allocation schedule?**

22 A14. The measurement basis for each allocation schedule is based on the design and
23 service requirements for each portion of the electrical system. Specifically,
24 forecasted energy is used for Power Plant Energy Production (Schedule 100)

Line
No.

1 required to serve customers. As customers use energy, they create a demand (rate
2 at which energy is used and/or delivered) on the system.

3
4 The output capacity of power plant production is designed considering the peak
5 demand requirements of the production system, measured as the bundled peak
6 demand. Production Schedule 200A is measured on forecasted bundled 12 CP and
7 Schedule 200B is measured based on the forecasted bundled 4CP. Schedule 201 –
8 Input to Transmission Substation is based on the forecasted 12CP of the of the
9 Service Area.

10
11 Schedules 202A, 202B, 202C, 203A, 203B, 203C, 204, and 205 refer to substations,
12 high voltage lines and transformers, which are designed to carry the maximum load
13 required by the customer classes they serve regardless of whether the class
14 maximum demand occurs at the same time or a different time as the system peak.
15 The forecasted non-coincident peak and individual customer maximum peak
16 demand is the measurement basis for these allocation schedules.

17
18 Low voltage secondary lines are designed to serve the absolute maximum demand
19 level of the customers they feed. Therefore, Schedule 300 is based upon the
20 forecasted sum of the individual customer maximum demands.

21

22 **Q15. How was the 2022 TSA used to develop the demand values determined for the**
23 **forecast allocation schedules?**

24 A15. The basis for the forecast allocation schedules developed for this instant case are
25 the forecasted net sales values presented in Witness Leuker's Exhibit A-15,

Line
No.

1 Schedule E1. However, because Witness Leuker's system peak demand forecast
2 does not contain the associated customer class level demand values necessary for
3 allocation schedule development, it was necessary to develop these corresponding
4 demand values by customer class. This was done by applying historical load factors
5 to the forecast energy values using industry standard load research principles to
6 derive demand values using energy and load factor. Therefore, forecast demands
7 were calculated by dividing the net forecast energy values without losses, by the
8 product of the historic load factor and annual hours.

9

10 **Q16. How were the appropriate historic load factors determined?**

11 A16. A 5-year average load factor was derived from years 2018-2022 and used for each
12 cost-of-service class.

13

14 **Q17. Why is using the 5-year average historical load factor a better representation**
15 **of the class's performance than the actual 2022 historic load factor?**

16 A17. Using the 5-year average load factor accounts for any abnormalities in any single
17 year and smooths out any variability due to weather, or other anomalies such as
18 economic conditions.

19

20 **Q18. Why is using average historical load factors a reasonable method of**
21 **determining forecast demand values?**

22 A18. There is a mathematical relationship between energy, load factor, and demand.
23 Forecasting demand is necessarily a function of forecasted sales and forecasted load
24 factors. Utilizing load factors to forecast demand values maintains the relationship
25 between energy and demand.

Line
No.

1 **Q19. How did you develop the forecast allocation schedules?**

2 A19. I applied the 5-year average load factors to the forecasted energy sales received
3 from Witness Leuker to produce the January 2025 to December 2025 forecast
4 schedules shown in Exhibit A-17, Schedule G1.1.

6 **Q20. How are line losses used in forecast allocation schedules?**

7 A20. Line loss factors are used as a multiplier in allocation schedules to increase the
8 energy or demand value for a given schedule to reflect the amount of production
9 needed to serve the customer class. Line losses were measured by voltage level,
10 allowing allocation schedules to accurately reflect demands on the system caused
11 by different classes of customers.

13 **Q21. Are the allocation schedules defined in your testimony developed using**
14 **established principles and methods?**

15 A21. Yes. I used the industry recognized and accepted load research principles. The
16 methods I used are consistent with the methods used by the Company in all its
17 electric general rate cases filed since 2014.

19 **Q22. How did you develop the Direct Current Fast Charging (DCFC) allocation**
20 **schedules?**

21 A22. The EV allocations process replicated the original allocation with the addition of
22 an EV class for power supply and distribution, utilizing billing determinants as
23 described later in my testimony.

24

Line
No.

1 **Power Supply Costs and Nuclear Surcharge**

2

3 **Q23. Is DTE Electric proposing to reset the base power supply cost in this**
4 **proceeding?**

5 A23. No. The base power supply cost reflected in Exhibit A-13, Schedule C4 consists of
6 two components: 1) base cost at generation, and 2) a loss factor. The Company is
7 proposing to update the loss factor in this case consistent with the method approved
8 in Case No. U-21297 and prior cases – it is not proposing any change to the base
9 power supply cost at generation originally established by the Commission in its
10 Order in Case No. U-15244. Since it was established, the amount of 31.26 mills per
11 kilowatt hour has been maintained in each of the Company's subsequent general
12 rate cases (Case Nos. U-15768, U-17767, U-18014, U-18255, U-20162, U-20561,
13 U-20836, and U-21297). I have applied a loss factor of 7.69% to this amount, which
14 results in a total PSCR base at the sales level of 33.66 mills per kilowatt hour as
15 reflected in Exhibit A-13, Schedule C4. If approved, this amount will become the
16 basis for recovery of the power supply costs with the same effective date as other
17 rate changes approved in this proceeding. This amount will be reflected in the
18 annual PSCR reconciliation, where the actual monthly PSCR revenue is a function
19 of the approved base and the PSCR sales.

20

21 **Q24. How did you determine the loss factor of 7.69%?**

22 A24. The loss factor of 7.69% is the average difference between the annual system output
23 and sales over the last five years ending with the historic test year, 2018 through
24 2022, as shown in Exhibit A-13, Schedule C4.1. This is the method approved by
25 the Commission in the Company's last rate case (Case No. U-21297).

Line
No.

1 **Q25. Have you projected any under or over recovery of power supply costs in this**
2 **proceeding?**

3 A25. No. For the purpose of the instant case, the power supply costs equal the associated
4 power supply revenues so there is no projected under or over recovery. Any actual
5 under or over recovery of power supply costs are reconciled annually in the PSCR
6 reconciliation filings. For purposes of this filing, Company Witness Bellini and I
7 have calculated present revenues using the existing base rates approved by the
8 Commission on December 1, 2023, in Case No. U-21297. We have used a zero
9 PSCR factor to calculate revenues for the projected test period.

10

11 **Q26. What does Exhibit A-13, Schedule C4 show?**

12 A26. This schedule calculates the power supply expense for the projected test period. As
13 stated earlier, the power supply costs and revenues are equivalent in the instant
14 case, so the projected costs are a function of the proposed PSCR base shown on line
15 3 and the projected power supply sales volumes on line 5. The transmission expense
16 on line 7 is the amount included in the current base, as originally approved in Case
17 No. U-15244. The power supply costs attributable to specific Rider 10, Rider 3
18 (sales shown together on line 16) and D13 sales (sales shown on line 17), are not
19 subject to the PSCR. Line 18 reflects total retail sales less Rider 10, Rider 3, and
20 D13. The corresponding costs are shown on Lines 21 and 22 for Rider 10 and Rider
21 3, and line 23 for D13. The total expense for the test period including transmission
22 expense is \$1,354 million, as shown on line 31. Lines 35 through line 40 show the
23 split of the total power supply expense between capacity and non-capacity, based
24 on the PA295 and PURPA related generation costs, capacity purchases and the net
25 energy market sales supported by Company Witness Burgdorf.

Line
No.

1 **Q27. What does Exhibit A-16, Schedule F6 show?**

2 A27. The Company's proposed nuclear surcharge is designed to collect the Proposed
3 Nuclear Surcharge Revenue. Exhibit A-16, Schedule F6 shows the calculation of
4 the Nuclear Surcharge, which recovers costs associated with nuclear site security
5 & radiation protection, and the funding for nuclear decommissioning and low-level
6 radioactive waste disposal. The proposed nuclear surcharge increase is due to
7 increases in site security and radiation protection costs as supported by Company
8 Witness Davis and lower forecasted jurisdictional sales.

9

10 **Rate Design**

11

12 **Q28. What does Exhibit A-16, Schedule F2 show?**

13 A28. This exhibit summarizes present and proposed revenues by rate schedule for the
14 12-month period ending December 31, 2025. Present revenues are based on rates
15 approved on December 1, 2023, in the Company's last general rate case, Case No.
16 U-21297. The exhibit provides a comparison of total present and proposed revenues
17 on page 2, present and proposed power supply revenues on page 3, and present and
18 proposed distribution revenues on page 4. The proposed power supply revenues on
19 page 3 provides a separate breakout of capacity and non-capacity related power
20 supply revenues.

21

22 **Q29. What does Exhibit A-16, Schedule F3 Revised show?**

23 A29. This exhibit shows the present and proposed rate design and corresponding revenue
24 by rate schedule based on the billing determinants for the 12-month period ending
25 December 31, 2025. The various billing components are listed in column (a), and

Line
No.

1 the respective billing determinants, including units of measure, are listed in column
2 (b). The billing determinants were developed based on historical data and
3 relationships, as well as known and measurable changes, and are consistent with
4 Company Witness Leuker's sales forecast. The existing rates, as approved by the
5 MPSC's Order in Case No. U-21297 on December 1, 2023, are in column (c), and
6 are used to calculate the present revenues in column (d). The rates proposed in this
7 proceeding are in column (e), with the resulting revenues in column (f).

8
9 The only exceptions to the layout described above are for pages 10, 22, 37, and 38
10 of Exhibit A-16, Schedule F3 Revised. Page 10 contains the rate design for a
11 residential rate schedule the Commission first approved in the Company's last
12 general rate case, Rate Schedule D1.13 Overnight Savers TOD. This rate schedule
13 is designed to be revenue neutral to the Company's proposed Rate Schedule D1.11
14 in this case. For this page of Exhibit A-16 Schedule F3 Revised, column (d) is the
15 proposed Rate Schedule D1.11 revenue. Column (e) contains the rates being
16 proposed for Rate Schedule D1.13, with the resulting revenues in column (f). A
17 comparison of the totals in columns (d) and (f) on this page shows the rate schedule
18 is designed to be revenue neutral to the proposed D1.11 Rate Schedule. A similar
19 structure is used on page 22, which contains new Rate Schedule D3.11 being
20 proposed for the first time in this case, being designed revenue neutral to Rate
21 Schedule D3. A similar structure is again used on pages 37-38, which contains new
22 Rate Schedule D14 being proposed for the first time in this case, being designed
23 revenue neutral to Rate Schedule D11. The proposed rate schedules D3.11 and D14
24 are described further below in my testimony.

Line
No.

1 **Residential Rate Design**

2 **Q30. What residential rate schedules does the Company currently offer?**

3 A30. The Company offers several rate schedules for residential customers:

- 4 • Rate Schedule D1 is the Company's former standard residential service rate,
5 which is now titled the Non-Transmitting Meter rate.
- 6 • Rate Schedule D1.11 is a product with rates that vary depending on season
7 and time of day and is the Company's standard residential service rate.
- 8 • Rate Schedule D1.13 is a product with rates that vary depending on season
9 and time of day and was approved in Case No. U-21297; it will be available
10 to customers no later than November 30, 2024.
- 11 • Rate Schedule D1.1 is a separately metered interruptible space conditioning
12 service rate.
- 13 • Rate Schedule D1.2 is a product with rates that vary depending on season
14 and time of day.
- 15 • Rate Schedule D1.6 is a product available to qualifying low-income
16 customers and supplies them with a \$40 monthly credit. The volumetric rate
17 design is consistent with Rate Schedule D1.
- 18 • Rate Schedule D1.7 is a separately metered rate available for supplemental
19 geothermal electric service with rates dependent on season and time of day.
- 20 • Rate Schedule D1.8 is a dynamic peak pricing product that has three pricing
21 periods based on time of day and that is periodically subject to critical peak
22 pricing.
- 23 • Rate Schedule D1.9 is a separately metered product for supplemental
24 service to charge electric vehicles.

Line
No.

- 1 • Rate Schedule D2 was available to customers for all electric service if all
- 2 space heating was total electric and installed on a permanent basis. It is now
- 3 available only to dwellings being served on the rate prior to December 17,
- 4 2015.
- 5 • Rate Schedule D5 is a separately metered interruptible electric water
- 6 heating product.

7

8 **Q31. What is the basis for the Company's proposed residential rate levels in this**

9 **proceeding?**

10 A31. The basis for the proposed rate levels are the functionalized power supply and

11 distribution deficiency/sufficiency amounts supported by Company Witness

12 Maroun as shown in his Exhibit A-16, Schedule F1.1, page 2 (for power supply)

13 and his Exhibit A-16, Schedule F1.2, page 1 (for distribution). The proposed

14 residential power supply and distribution charges were designed to meet the power

15 supply and distribution deficiencies shown in these exhibits. The proposed

16 residential power supply capacity and non-capacity rates were designed to recover

17 the revenues pursuant to Company Witness Maroun's Exhibit A-16, Schedule F1.5,

18 which shows how much of the power supply revenue requirement for each rate

19 class is capacity and non-capacity related.

20

21 Within the power supply cost of service, Company Witness Maroun identifies three

22 separate residential cost classes: "D1.11/Other", "D1.2", and "D2". All current

23 residential rate schedules except D1.2 and D2 are included in D1.11/Other. For the

24 D1.11/Other rate schedules, the power supply deficiency was allocated based on

25 each rate schedule's percentage contribution to the present D1.11/Other power

Line
No.

1 supply revenue. For those rate schedules with their own cost of service class (D1.2
2 and D2), the deficiency was directly allocated to the corresponding class. This is
3 the same method used to develop the approved residential power supply rates in the
4 Company's last rate case, Case No. U-21297.

5
6 **Q32. Are you proposing any changes to power supply rate design on residential rate**
7 **schedules?**

8 A32. Yes. The Company is proposing to design Rate Schedule D1.7 non-capacity
9 charges on a time-of-use basis such that the D1.7 non-capacity rate structure would
10 be the same as the D1.7 capacity rate structure – pricing differentials are consistent
11 with the ordered D1.7 power supply design in Case No. U-20836. This approach is
12 similar to currently approved Rate Schedules D1.11, D1.2, and D1.8. This change
13 will further align rate design methodologies across the residential rate schedules.

14
15 **Q33. What is the Company's proposed residential distribution rate design?**

16 A33. In the Company's rate case filed in 2014, Case No. U-17767, MPSC Staff
17 recommended, and the Commission approved, variable distribution rates designed
18 such that all customers in the Residential class would have the same rate, with the
19 caveat that a cap was applied to limit the increase of any specific variable
20 distribution rate. This method was again proposed and approved in each of the
21 Company's subsequent rate cases. The Company designed the variable distribution
22 rates for each residential rate schedule in this case using this same premise. The
23 Residential class rate schedules now all have the same distribution rate, and thus no
24 cap on any individual Residential Secondary rate schedule's distribution rate is

Line
No.

1 applied in this case. The one exception is Rate Schedule D1.13, which has variable
2 distribution rates designed consistent with the Order in Case No. U-21297.

3

4 **Q34. What does Exhibit A-16, Schedule F4 show?**

5 A34. This exhibit shows a comparison of typical monthly bills by rate schedule based on
6 present and proposed rates. For each rate schedule, the exhibit calculates the
7 amount of a bill under existing rates and proposed rates across a broad range of
8 energy consumption levels. The difference is representative of the impact of the
9 proposed rate changes.

10

11 **Q35. What did the Commission Order with respect to Rate Schedule D1.6 in Case**
12 **No. U-21297?**

13 A35. The Company, in Case No. U-21297, proposed to transition Rate Schedule D1.6
14 customers to Rate Schedule D1.11, make the Low-Income Assistance credit
15 available on additional residential base rates (compared to only D1.6 at present),
16 and close Rate Schedule D1.6. The Commission declined to approve the
17 Company's proposal and instead said "DTE Electric Company shall conduct an
18 impact study before retiring Rate Schedule D1.6 and transitioning customers to
19 Rate Schedule D1.11."²

20

21 **Q36. What is the Company's proposal in this case for Rate Schedule D1.6 and the**
22 **associated Low Income Assistance credit?**

23 A36. The Company proposes three specific actions³:

² December 1, 2023, Order in Case No. U-21297, Pg 372

³ Separate and apart from these three specific actions, Company Witness Sparks proposed to increase the LIA credit from \$40 to \$50

Line
No.

- 1 • Open availability of the low-income assistance (LIA) credit, which
- 2 currently requires the customer to switch from their existing rate schedule
- 3 to D1.6, to all residential base rates. This would eliminate the requirement
- 4 that customers seeking the LIA credit must take service on D1.6. All other
- 5 requirements for the LIA would remain as they are presently.
- 6 • Transition current D1.6 customers to D1.11, the Company's default
- 7 residential rate schedule, while allowing customers receiving the credit to
- 8 modify their service to any other residential base rate for which they are
- 9 otherwise eligible. Any D1.6 customer with a non-transmitting meter will
- 10 be transitioned to Rate Schedule D1 Non-Transmitting Meter rate in the
- 11 alternative.
- 12 • Retire Rate Schedule D1.6 as the final piece of the Company's transition to
- 13 time of use rates for residential customers⁴, a process which formally
- 14 commenced with the Commission's April 18, 2018, Order in Case No. U-
- 15 18255 and was completed in Spring 2023.

16

17 **Q37. Why does the Company believe customers receiving, or desiring to receive, the**

18 **low-income assistance credit should have choice in which rate schedule they**

19 **are on?**

20 A37. Customers should have optionality in their base rates and the opportunity to choose

21 the option that is best for their energy usage circumstances. Today, LIA-recipient

22 customers have one rate schedule available to them. The Company proposes to

23 extend this to all residential base rate schedules, which for most customers includes

24 D1.11, D1.2, D1.8, and D1.13, consistent with the options available to all other

⁴ Notwithstanding the small number of customers remaining on Rate Schedule D1 Non-Transmitting Meter Rate

Line
No.

1 residential customers. There is no basis to limit options for this specific group of
2 customers.

3

4 **Q38. Did the Company conduct an impact study of a transition from Rate Schedule**
5 **D1.6 to Rate Schedule D1.11?**

6 A38. Yes. The Company calculated a distribution of customer impacts on D1.6 and
7 D1.11 using 2022 actual sales for customers who in 2022 were served on D1.6⁵ and
8 rates effective following the implementation of Case No. U-20836. The analysis
9 ultimately included 26,126 such customers. The purpose of this analysis was to
10 determine if there is structurally adverse impact of transitioning customers from
11 D1.6 to D1.11; it does not reflect customer behavior change nor does it reflect a
12 forecast of actual outcomes related to this case. Actual bills vary based on a variety
13 of factors including weather, rate schedule, and the timing/volume of usage.

14

15 **Q39. Did the impact study identify a structurally adverse impact of transitioning**
16 **D1.6 customers to D1.11?**

17 A39. No. The average impact of a customer transitioning from D1.6 to D1.11 is a
18 decrease of their bill of 0.17%. Given the average impact is near zero, this confirms
19 there is no structurally adverse impact. Rate Schedule D1.6 maintains the legacy
20 structure previously utilized by most DTE residential customers, which is known
21 as an “inverted block rate”. This type of rate charges customers more per kilowatt
22 hour at a specified level of usage – in the case of D1.6 that level is +/- 17 kilowatt
23 hours per day. Before the implementation of advanced meters, it was an effective
24 way to design a rate which incentivized the efficient use of energy. However, with

⁵ With a minimum of 300 billing days

Line
No.

1 the wide implementation of advanced meters, time-of-use rates are a more precise
2 way to design rates than an inverted block approach. They charge higher rates when
3 the cost to provide electricity is higher instead of simply when more is consumed.
4 Necessarily, customers will have somewhat different bill outcomes on different rate
5 designs based on how and when they use energy.
6 In general, customers with higher average usage tend to benefit on D1.11 and
7 customers with lower average usage tend to benefit on the inverted block rate. For
8 context, in the instant case, the Company is forecasting average monthly sales per
9 customer of ~631 kWh on Rate Schedule D1.6 and ~582 kWh on Rate Schedule
10 D1.11⁶. This dynamic is further described in Table 1 below.

11

12

Table 1 Customer usage and impact statistics

	Lower bill on D1.11	Lower bill on D1.6
Customers in analysis	15,220	10,906
Average usage per month	785 kWh	486 kWh
Average usage >17kWh/mo.	32%	13%
Average % difference in bill	(0.66%)	0.52%
Average \$ difference in bill	(\$1.29)	\$0.51

13

14 And as the chart below (Figure 1.) describes, there is a narrow distribution of bill
15 changes when comparing D1.6 and D1.11 and the average change is a very slightly
16 lower bill on D1.11 – 58% of customers in the analysis would see a lower bill on
17 D1.11, all else equal.

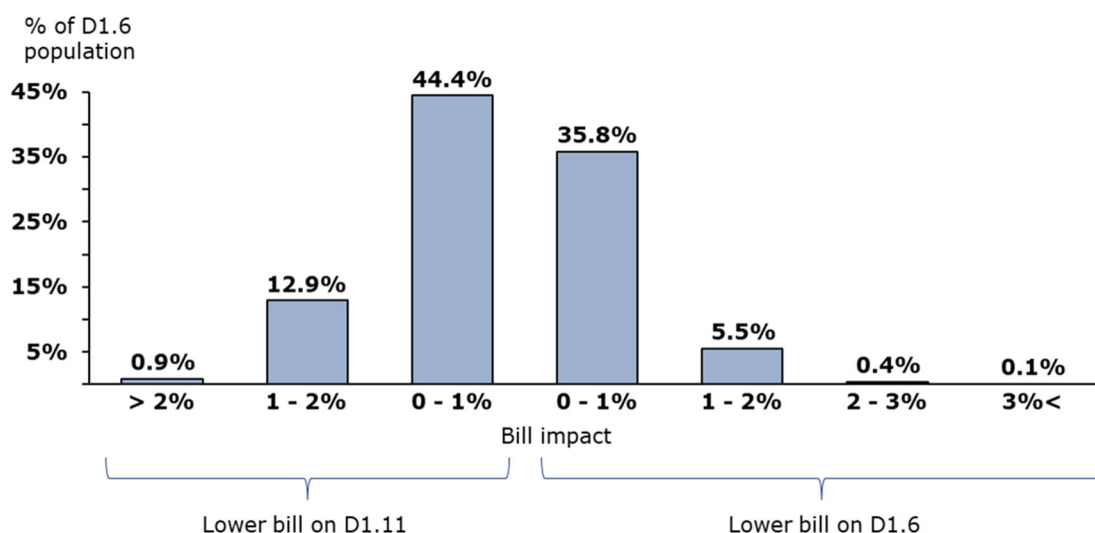
18

⁶ See Exhibit A-14, Schedule F3 [Revised](#)

Line
No.

1

Figure 1. Difference in bill on D1.11 compared to D1.6



2

3 **Q40. Given the results of the study and your demonstration that there is no**
4 **structurally adverse impact of the proposal, what is your recommendation to**
5 **the Commission?**

6 A40. I recommend the Commission approve the Company's proposal to:

- 7 • Open LIA credit availability to all residential base rates
- 8 • Transition D1.6 customers to D1.11
- 9 • Retire D1.6

10 Upon approval the Company would complete rate transition and retirement by the
11 end of the projected test year.

12

13 Rider 18 Outflow Credits

14 **Q41. What does Exhibit A-16, Schedule F7, pages 1 through 2 show?**

15 A41. In Case No. U-20836, the Commission approved the Staff's method to calculate the
16 outflow credit for customers taking service under Rider 18 (Distributed
17 Generation). That same calculation method was utilized by the Company and once

Line
No.

1 again approved in its last general rate case, Case No. U-21297. The outflow credit
2 is based on power supply rates. Pages 1 and 2 of this exhibit show the calculation
3 of the proposed outflow rates for each rate schedule by adding the non-capacity rate
4 (column b) and capacity rate (column c). The outflow credits are calculated using
5 the same methodology proposed by Staff and approved by the Commission in Case
6 Nos. U-20836 and U-21297.

7

8 **Q42. Do the power supply outflow credits calculated on Exhibit A-16, Schedule F7**
9 **and shown on Exhibit A-16, Schedule F8 (Sheet Nos. D-115.00 and 116.00),**
10 **include the current PSCR factor?**

11 A42. No. Given the more frequent changes in the PSCR factor, for administrative
12 convenience, the PSCR factor is not included. However, as stated in the currently
13 approved Rate Book on Sheet No. D-114.00, when calculating the actual outflow
14 credit applied to customer bills, the Company will add or subtract the current PSCR
15 factor (which is shown on Sheet No. C-62.00) to the rates shown on Sheet Nos. D-
16 115.00 and D-116.00. Rate Schedule D13 outflow credits would not be adjusted
17 by PSCR as those customers are not subject to PSCR.

18

19 **Commercial Secondary Rate Design**

20

21 **Q43. Can you please provide a brief description for each of the Company's**
22 **commercial secondary rate schedules?**

23 A43. Yes, the following descriptions are in the order shown in Exhibit A-16, Schedule
24 F3 Revised.

Line
No.

- 1 • Rate Schedule D1.1 is a separately metered interruptible space conditioning
- 2 service rate.
- 3 • Rate Schedule D1.7 is a separately metered rate available for supplemental
- 4 geothermal electric service with rates dependent on season and time of day.
- 5 • Rate Schedule D1.8 is a dynamic peak pricing product with three time of
- 6 day pricing periods that is periodically subject to critical peak pricing.
- 7 • Rate Schedule D1.9 is a separately metered product for service to charge
- 8 electric vehicles.
- 9 • Rate Schedule D3 is our general service rate for non-residential customers.
- 10 • Rate Schedule D3.1 is an unmetered general service rate available to
- 11 customers for loads which are impractical to meter.
- 12 • Rate Schedule D3.2 is a secondary educational rate available for school,
- 13 college, or university customer locations.
- 14 • Rate Schedule D3.3 is available to customers desiring interruptible service.
- 15 • Rate Schedule D3.5 is a Company owned charging service and includes
- 16 on/off peak non-capacity energy charges and a session fee.
- 17 • Rate Schedule D4 is the Company's large general service rate and includes
- 18 a demand charge.
- 19 • Rate Schedule D5 is an interruptible electric water heating rate available to
- 20 commercial customers based on certain size criteria.
- 21 • Rate Schedule E1.1 is for any metered energy provided to municipality-
- 22 owned streetlights.
- 23 • Rate Schedule Rider 7 is available to customers with high intensity lighting
- 24 requirements, such as greenhouses.

Line
No.

- 1 • Finally, Rate Schedule Rider 8 is available to customers with total electric
2 commercial space conditioning needs.

3

4 **Q44. What is the basis for the Company's proposed commercial secondary rates in**
5 **this proceeding?**

6 A44. The proposed commercial secondary power supply and distribution charges were
7 designed to meet the respective deficiencies shown in Company Witness Maroun's
8 Exhibit A-16, Schedule F1.1, page 2 (for power supply) and Exhibit A-16, Schedule
9 F1.2, page 1 (for distribution). The proposed power supply capacity and non-
10 capacity rates were designed to recover the revenues pursuant to Company Witness
11 Maroun's Exhibit A-16, Schedule F1.5, which shows how much of the power
12 supply revenue requirement for each rate class is capacity and non-capacity related.

13

14 **Q45. How are the power supply revenue targets allocated in your rate design?**

15 A45. I followed the same methodology utilized in Case No. U-21297 to allocate both the
16 capacity and non-capacity power supply revenue requirements to the individual
17 tariffs within the secondary class. In his cost-of-service analysis, Company Witness
18 Maroun identifies three separate cost classes: one specific to Rate Schedule D3.2,
19 one specific to Rate Schedule D4, and one to capture Rate Schedule D3 and all
20 remaining rate schedules. The revenue requirements for D3.2 and D4 are assigned
21 directly to the respective class. The revenue requirement for the D3 and other
22 subgroup is further allocated based on each tariff's percentage contribution to the
23 total present power supply revenue for that same subgroup.

24

25 **Q46. How were the commercial secondary energy rates determined?**

Line
No.

1 A46. With the exception of rate schedules D3.5 and D4, all commercial secondary power
2 supply rates are energy based. After allocating the revenue targets to each
3 individual rate schedule as discussed earlier, I divided the capacity and non-
4 capacity targets for each rate schedule by the associated power supply sales to
5 determine the capacity and non-capacity energy rates, respectively. The rate
6 structure for Rate Schedule D3.5 has a non-capacity energy charge based on time
7 of use and a session fee which includes power supply capacity and is based on the
8 demand rating of the charging station, consistent with the approved rate design in
9 Case No. U-21297. The rate structure for Rate Schedule D4 has a capacity power
10 supply demand charge which is set at a level to recover the full capacity revenue
11 requirement, consistent with the methodology approved in Case Nos. U-18248, U-
12 18255, U-20105, U-20162, U-20561, U-20836, and U-21297. The non-capacity
13 revenue for D4 is currently collected through a non-capacity demand charge, and
14 two separate energy charges, dependent on the total hours use of demand.

15

16 **Q47. Did you make any changes from previous rate design?**

17 A47. Yes. For Rate Schedule D1.7 (Secondary), I designed the proposed non-capacity
18 power supply rates to vary across summer and winter and by time of use period.
19 The previous design utilized a flat non-capacity energy charge. This change ensures
20 consistency with the existing rate design on D1.7 as well as mimics the proposed
21 design structure for residential D1.7.

22

23 **Q48. How does Company Witness Maroun's revenue deficiency/sufficiency for**
24 **distribution presented in this instant case impact your rate design?**

Line
No.

1 A48. My rate design in this instant case is consistent with the rate design methodology
2 used by the MPSC Staff to calculate rates which were approved by the Commission
3 in Case Nos. U-18014, U-18255, U-20105, U-20162, U-20561, U-20836 and most
4 recently, U-21297. The Company and MPSC Staff maintained the position in each
5 of these cases that if the customers are alike enough to be classified together, their
6 distribution rates should also be alike to the extent possible.

7

8 **Q49. How did you design Rate Schedule D3.5?**

9 A49. Rate Schedule D3.5 is the Company's Charging Hub Rate. It has zero forecast
10 determinants in this case and, as such, I increase the energy charges by the same
11 percentage as Rate Schedule D3 power supply charges.

12

13 **Q50. Are you proposing changes to the secondary service charges in this case?**

14 A50. No.

15

16 **Q51. Are you proposing any new commercial secondary rate schedules?**

17 A51. Yes. In compliance with the December 1, 2023, Order in Case No. U-21297, pg.
18 372, which said "[f]or its next general rate case, DTE Electric Company shall
19 develop and present optional time-of-use rates for its commercial secondary and
20 primary customers", the Company is proposing an optional time of use rate for
21 commercial secondary customers. Proposed Rate Schedule D3.11 is further
22 described below and reflected in my Exhibit A-16, Schedules F3 Revised and F8.
23 The proposed rate is fully optional, and the Company is not proposing to transition
24 any customer to the rate without a customer-initiated request.

25

Line
No.

1 **Q52. Are you including any additional commercial secondary rate schedules?**

2 A52. Yes. I am also including rates designed for electric vehicle fast charging pursuant
3 to the Order in Case No. U-21297, pg. 373, which said “DTE Electric Company
4 shall conduct a separate cost of service study to allocate appropriate costs to fast
5 charging and design and propose rates for this specific class of customer”. As
6 described by Company Witness Maroun, the cost of service and rate design is for
7 discussion and not proposed for implementation in the instant case. As such, the
8 Company has not included it in Exhibit A-16 Schedule F2, F3 Revised, or F8. The
9 rate design is provided in Exhibit A-16, Schedule F9 Revised.

10

11 Commercial Secondary Time of Use

12 **Q53. How is proposed Rate Schedule D3.11 designed?**

13 A53. The rate schedule is designed to be revenue neutral to Rate Schedule D3 until there
14 is sufficient historical usage to determine the utility of, and potentially implement,
15 a separate revenue line in the D3/Other cost of service class, or a separate cost of
16 service class. This approach also reduces the near-term risk of forecasting customer
17 adoption on the new rate and any associated usage changes on existing rates. Thus,
18 the rate utilizes the same overall billing determinants, cost allocations, and
19 underlying revenue requirements as D3 in this case, similar to the initial D1.11
20 proposal in Case No. U-20836. The proposed tariff included in Exhibit A-16,
21 Schedule F8 requires any customer electing D3.11 to remain on that rate for at least
22 12-months before switching to another rate.

23

24 In addition, the proposed tariff caps enrollment on the rate at 1,000 customers to
25 account for potential unanticipated usage patterns on the rate – this is consistent

Line
No.

1 with the Commission approval of Rate Schedule D1.13, a residential, voluntary
2 time of use rate, in Case No. U-21297. The Commission approved a cap of 10,000
3 customers, or ~0.5% of the Company's approximately 2 million residential
4 customers in that case. Considering the same 0.5% percentage and the ~200k
5 commercial secondary customers forecasted in this case suggests 1,000 customers
6 as an appropriate starting point.

7

8 **Q54. What are the proposed power supply time of use pricing periods?**

9 A54. The Company proposes that Rate Schedule D3.11 power supply vary based on
10 season and time of day, consistent with the Company's default residential rate
11 schedule. The on-peak hours remain constant across the year to support customer
12 understanding and to maintain simplicity in the Company's rates.

13 • Season

14 ○ Summer pricing in effect June – September

15 ○ Non-summer pricing in effect from October - May

16 • Time of day

17 ○ On-peak from 1:00pm – 5:00pm, Monday – Friday

18 ○ Off-peak in all other hours

19

20 **Q55. What is the basis for the 1:00 – 5:00pm on-peak period?**

21 A55. This period aligns with both the system coincident peaks during the summer
22 months⁷ as well as the secondary class peaks in the summer months. Considering
23 the period 2018 – 2022, 18 of 20 summer system coincident peaks occur within the
24 proposed on-peak hours, and all 20 of the summer secondary class peaks occur

⁷ June, July, August, September

Line
No.

1 within the proposed on-peak period⁸. This alignment ensures the on-peak period
2 reflects those periods of highest use on the system and the highest system use of
3 this customer group, encouraging system-efficient usage.

4

5 **Q56. How did you develop the determinants and the power supply pricing**
6 **differential between the peak periods and the seasons?**

7 A56. I allocated determinants to each pricing period based on (1) historic D3 actuals and
8 (2) an assumed on-peak to off-peak shift of 8.2% for the summer months and 3.3%
9 for the non-summer months. These shifts reflect the expected change in behavior
10 for customers electing service on this rate. The Company's Advanced Customer
11 Pricing Pilot included a rate with the same pricing differential approach (relative
12 LMP and TOU structure for both capacity and non-capacity power supply) and opt-
13 in enrollment, which mimics the method by which customers would enroll on
14 D3.11. Therefore, this is the best available proxy for expected shifts in usage.

15

16 For power supply pricing differentials, I utilized the relative difference in LMP for
17 the years 2020-2022 between the periods and seasons. This is consistent with the
18 method approved by the Commission for rate schedule D.11, which varies power
19 supply costs using the relative difference in LMP.

20

21 **Q57. How are the distribution rate and service charge design?**

22 A57. Both the distribution rate and monthly service charge are designed consistent with
23 Rate Schedule D3. The distribution rate is a flat, non-time variant rate.

24

⁸ Data as reflected in Part III Attachment 5 (29)

Line
No.

1 **Q58. What are the proposed prices considering both the periods and methodology**
2 **and what is the resulting differential?**

3 A58. The table below describes the total volumetric prices for each period⁹, and “all in”
4 differential. Off peak does not vary by season.

	Rate (¢/kWh)	Differential to Off Peak
Summer On Peak	19. ~~73~~ 49	1.38x
Non-Summer On Peak	14. ~~82~~ 67	1.04x
Off Peak	14. ~~25~~ 44	1.00x

6

7

8 **Q59. When would this rate schedule be effective if approved by the Commission?**

9 A59. Upon approval from the Commission, the rate would need to be developed, tested,
10 and implemented in the Company’s billing system. As such, and as reflected in my
11 Exhibit A-16, Schedule F8, the Company intend to have the rate available for
12 customers no later than the end of the projected test year in the instant case
13 (December 31, 2025).

14

15 *EV Fast Charger Rate Design*

16 **Q60. Please summarize the Company’s EV Fast Charger Rate Design.**

17 A60. The Company’s proposed EV fast charger rate is designed as a secondary voltage
18 rate with time of use power supply pricing which varies by time period and season.
19 Power supply capacity and non-capacity rates are designed to recover the respective
20 revenue requirements allocated by Company Witness Maroun. Both capacity and

⁹ Consisting of power supply capacity, power supply non-capacity, and distribution only.

Line
No.

1 non-capacity include an on-peak period of 1:00 – 5:00pm, Monday-Friday, and a
2 seasonal component with summer rates effective June, July, August, and
3 September, and non-summer rates effective in all other months. The pricing
4 differential between the four pricing periods is based on the relative differences in
5 LMP, consistent with the proposed Rate Schedule D3.11 and the currently effective
6 Rate Schedule D1.11. Delivery rates are designed to recover the revenue
7 requirements allocated by Company Witness Maroun, including a service charge
8 consistent with Rate Schedule D3. The distribution rate is designed as a flat
9 volumetric rate. All surcharges are consistent with a similarly situated D3 customer.

10

11 **Q61. How did the Company develop the determinants and load shape for the rate?**

12 A61. The Company utilized usage from current, known EV fast chargers to develop the
13 determinants for the rate. Company Witness Bennett provided me a list of 68 known
14 EV fast chargers customers taking service from the Company. In order to isolate
15 EV fast chargers from other load and appropriately design this rate, I used
16 information from those chargers on separate meters as the basis for the load shapes.
17 I also excluded chargers with fewer than 300 read days, which typically indicates a
18 charger installed sometime during the analysis period. Ultimately, the determinants
19 and rate design leverage historical data from a total of 21 chargers.

20

21 **Q62. Do you have any concerns about the data sample size or quality?**

22 A62. Yes. As noted above, there are approximately 68 known EV fast charger customers
23 served by the Company, of which 21 were usable for this analysis. While this data
24 supports a reasonable first step of analysis for discussion purposes, it is apparent

Line
No.

1 that the ability to identify all EV fast charger load and to isolate it from other co-
2 located load has limitations. Thus, this data has two notable constraints:

3 1) The sample size is small because the overall density of EV fast chargers is still
4 small relative to customer counts in other cost of service classes. Very small
5 cost of service classes such as this one can lead to volatile determinants, COS,
6 and rate design from case to case and individual customers may have an
7 outsized impact on the overall class.

8 2) The sample size, while reasonably defined, does not include all EV fast chargers
9 served by the Company given the co-location of charging load with other
10 general service loads.

11

12 **Q63. What do you recommend the Commission order with respect to the EV Fast**
13 **Charger Rate?**

14 A63. The Company acknowledges the merit in continuing this discussion. The data
15 constraints and generally small customer set indicate that this proposal should be
16 used as a starting point for discussion only and not as a rate to be implemented at
17 the conclusion of this case.

18

19 **Primary Rate Design**

20 **Q64. Can you please provide a brief description for each of the Company's primary**
21 **customer rate schedules?**

22 A64. Yes, the Company offers several primary rates.

- 23 • Rate Schedule D11 is the Company's main primary rate schedule and is
24 available to customers served at primary, sub-transmission, or transmission
25 voltage.

Line
No.

- 1 • Rate Schedule D6.2 is available to educational institution customer
- 2 locations (schools, colleges, or universities) desiring service at primary,
- 3 sub-transmission, or transmission voltage.
- 4 • Rate Schedule D8 is the Company's primary voltage interruptible rate
- 5 which is limited to 300 megawatts.
- 6 • Rate Schedule D10 is the Company's all-electric school building rate
- 7 (including electric space and water heating).
- 8 • Rate Schedule D12 is the Company's Experimental Large Customer Low
- 9 Peak Demand Supply rate.
- 10 • Rate Schedule D13 is the Company's XL Large Industrial Rate.
- 11 • Riders 1.1 and 1.2 are specific interruptible rates for customers operating
- 12 electric furnaces for metal melting (Rider 1.1) or using electric heat as an
- 13 integral part of manufacturing (Rider 1.2).
- 14 • The Company's Rider 3 rate provides standby service for various customers
- 15 with generation facilities operating in parallel with the Company's system.
- 16 • Rider 10 is an interruptible supply rate available to customers with larger
- 17 interruptible loads.

18

19 **Q65. How were the capacity and non-capacity charges determined for the primary**
20 **rate schedules?**

21 A65. My proposed primary rate designs result in power supply rates which are set equal
22 to cost-to-serve. Company Witness Maroun determined the capacity and non-
23 capacity revenue requirement for each cost-of-service class, which are shown in his
24 Exhibit A-16, Schedule F1.5. For primary rates with billing demand components,
25 capacity rates were designed to collect the total capacity revenue requirement

Line
No.

1 through the billing demand charges. For primary rates that do not have billing
2 demand components, capacity rates were designed to collect capacity revenue
3 requirement through energy charges. Generally, non-capacity rates were designed
4 to recover non-capacity revenue requirement through energy and/or demand
5 charges.

6

7 **Q66. Did you make any changes from previous rate design?**

8 A66. No.

9

10 **Q67. How were the Distribution charges determined for the primary rate**
11 **schedules?**

12 A67. The Company's proposed primary delivery rates are cost based by voltage level,
13 utilizing the distribution base revenue deficiency/sufficiency levels by voltage class
14 shown in Exhibit A-16, Schedule F1.2 and sponsored by Company Witness
15 Maroun. Exhibit A-16, Schedule F5 shows the development of the voltage level
16 Distribution Demand Charges for the primary tariffs. The present (U-21297 Base
17 Rates) base delivery revenue by voltage level for each rate schedule is shown in
18 column (a). The base delivery revenue includes all revenues from service charges,
19 distribution energy and demand charges, and substation credits. The cost-based
20 deficiency/sufficiency for each service voltage level, from Exhibit A-16, Schedule
21 F1.2, sponsored by Company Witness Maroun, are shown in column (b). Column
22 (c) shows the total proposed base delivery revenue to be collected from each voltage
23 level, which is the sum of columns (a) and (b). Columns (d) and (e) show the
24 proposed service charge revenue and substation credits. Columns (d) and (e) are
25 subtracted from column (c) to determine the amount of base delivery revenue to be

Line
No.

1 collected in distribution demand charges, shown in column (f). The distribution
2 demand revenue in column (f) was divided by the distribution demands in column
3 (g) to determine the distribution demand charges by voltage level shown in column
4 (h).

5
6 **Q68. Will all primary customers pay the same \$/kW distribution charges (i.e., an**
7 **equivalent amount as shown in column (h))?**

8 A68. All primary rates will have the same \$/kW charges shown in column (h) with the
9 exception of rate D10 and riders R1.1 and R1.2 which have energy-based delivery
10 charges. For rate D10 and riders R1.1 and R1.2, I have calculated energy charges
11 equivalent to the proposed voltage level distribution charges. Rate Schedule D13 is
12 also a primary rate schedule with energy-based delivery charges and is discussed
13 below.

14
15 **Q69. How is Rate Schedule D12 designed?**

16 A69. Rate Schedule D12 is designed to have increases consistent with D11. There are no
17 present or forecasted sales on D12 and, as such, this method is appropriate. Power
18 supply rates are increased at the same percentage increase as D11, and distribution
19 rates are consistent with the voltage level rates for all primary service customers.

20
21 **Q70. How is Rate Schedule D13 designed?**

22 A70. The proposed design is consistent with the approved design in Case No. U-21297
23 and utilizes Blue Water Energy Center (BWEC) as a proxy indication of marginal
24 cost to serve. Proposed capacity rates maintain the levelized cost of BWEC capacity
25 approved by the Commission in successive case, including Case No. U-21297, and

Line
No.

1 are unchanged. Proposed non-capacity rates utilize BWEC proxy costs using a
2 fixed heat rate assumption which is unchanged from Case No. U-21297, forecasted
3 natural gas costs as described in the Company's direct testimony and exhibits in
4 Case No. U-21425¹⁰, and a non-fuel O&M assumption. Proposed transmission rates
5 reflect the incremental cost of transmission to the Company resulting from
6 projected D13 load. The proposed administrative charge reflects the incremental
7 cost to administer the Rate Schedule and is unchanged. Distribution rates are
8 consistent with the voltage level distribution rates for primary, sub transmission,
9 and transmission voltage. Distribution rates are designed as volumetric assuming a
10 75% load factor. The customer charge is consistent with those proposed for all
11 primary customers.

12
13 **Q71. Are you proposing changes to the primary rate service charges?**

14 A71. No.

15
16 **Q72. Are you proposing any new primary rate schedules?**

17 A72. Yes. Consistent with the December 1, 2023, Order in Case No. U-21297, pg. 372,
18 which said "[f]or its next general rate case, DTE Electric Company shall develop
19 and present optional time-of-use rates for its commercial secondary and primary
20 customers", the Company is proposing an optional time of use rate for primary
21 customers. Proposed Rate Schedule D14 is further described below and reflected
22 in my Exhibit A-16, Schedules F3 Revised and F8. The proposed rate is fully
23 optional, and the Company is not proposing to transition any customer to the rate
24 without a customer-initiated request.

¹⁰ Exhibit A-14, CY 2025

Line
No.

1 **Q73. How is proposed Rate Schedule D14 designed?**

2 A73. The rate schedule is design to be revenue neutral to rate schedule D11 until there is
3 sufficient historical usage to determine the utility of, and potentially implement, a
4 separate cost of service class or a separate revenue line within D11/Other. This
5 approach also reduces the complexity of forecasting customer adoption on the new
6 rate and any associated usage changes on existing rates. Thus, the rate utilizes the
7 same overall billing determinants, cost allocations, and underlying revenue
8 requirements as D11 in this case. The time of use structure applies to power supply
9 charges, while distribution charges remain demand charges based on voltage level
10 and consistent with other primary rate schedules.

11

12 **Q74. What are the proposed time of use pricing periods?**

13 A74. The Company proposes that Rate Schedule D14 vary based on season and time of
14 day. The on-peak hours remain constant across the year to support customer
15 understanding and to maintain simplicity in the Company's rates.

16 • Season

17 ○ Summer pricing in effect June – September

18 ○ Non-summer pricing in effect from October - May

19 • Time of day

20 ○ On-peak from 11:00a – 7:00p, Monday – Friday, excluding holidays
21 as defined in Section C11 of the Company's rate book. This is
22 consistent with the existing on-peak hours for rate schedule D11, the
23 Company's standard primary voltage rate

24 ○ Off-peak in all other hours

25

Line
No.

1 **Q75. How did you determine the pricing differential between the peak periods and**
2 **the seasons?**

3 A75. I utilized the relative difference in LMP for the years 2020-2022 to define the
4 pricing differentials between the periods and seasons. This is consistent with the
5 design approved by the Commission for Rate Schedule D1.11 and proposed for
6 Rate Schedule D3.11, which varies power supply costs using the relative difference
7 in LMP.

8

9 **Q76. What are the proposed prices, considering both the periods and methodology,**
10 **and the resulting differentials?**

11 A76. The table below describes the pricing differentials for energy-only power supply.
12 Distribution rates continue to be demand-based, are determined separately, and are
13 not reflected in the table. Off peak does not vary by season.

14

	Rate (¢/kWh)	Differential to Off Peak
Summer On Peak	10.67	1.68x
Non-Summer On Peak	7.38	1.16x
Off Peak	6.35	1.00x

15

16

17 **Q77. What are the risks of customers shifting from D11 to the proposed D14?**

18 A77. D11 is a demand-based rate which, all else being equal, encourages more efficient
19 usage of the system. More efficient usage results in a lower average cost. Customers
20 who use more energy per increment of demand (i.e., they have a higher load factor)
21 have a lower average volumetric rate compared to a customer with the same

Line
No.

1 demand but lower total energy usage. The average load factor implied in the
2 Company's proposed D11 power supply billing determinants is 73%¹¹. A D11
3 customer with a load factor higher than 73% would expect to see a relatively lower
4 than average volumetric rate on D11, and a customer with a lower load factor would
5 see a relatively higher than average rate on D11. This difference in average rates is,
6 simply, a reflection of the relatively different cost to serve each customer based on
7 the efficiency of their energy usage.

8
9 The proposed Rate Schedule D14 eliminates this dynamic for power supply charges
10 and substantially reduces the incentive for customers to operate efficiently and
11 manage their relative demand on the system. Until such time that D14 is supported
12 by its own cost of service class, this may lead to an under-recovery of cost, which
13 would ultimately be allocated to other customers in a subsequent case. As such, the
14 Company proposes to limit total load on this rate to 50 MW of contract capacity.
15 The Company proposes a minimum contract term of 36-months, which will support
16 stability in cost of service and pricing and limit opportunities to arbitrage between
17 D14 and D11.

18

19 **Q78. When would this rate schedule be effective if approved by the Commission?**

20 A78. Upon approval from the Commission, the rate would need to be developed, tested,
21 and implemented in the Company's billing system. As such, and as reflected in my
22 Exhibit A-16, Schedule F8, the Company intends to have the rate available for

¹¹ In total, without respect to voltage level, and only for power supply determinants. The figure is used here for illustration of a conceptual discussion about load factor and not for the purposes of ratemaking. See Exhibit A-16, Schedule F3 Revised

Line
No.

1 customers no later than the end of the projected test year in the instant case
2 (December 31, 2025).

3

4

Investment Recovery Mechanism (IRM) Surcharge

5

6 **Q79. What is the basis for your proposed surcharge design?**

7 A79. The proposed IRM includes exclusively distribution investments, and therefore it
8 is most appropriate to design the surcharge consistent with distribution rate design
9 generally. Company Witness Maroun provided IRM revenue requirements
10 allocated among the existing distribution cost of service classes, which include
11 Residential Secondary, Commercial Secondary, Primary, and Subtransmission, and
12 four classes related to lighting. Consistent with the IRM surcharge rate design
13 approved in Case No. U-21297 and the testimony of Company Witnesses Vangilder
14 and Maroun, I designed surcharges for each distribution cost of service class and
15 rate schedule (as applicable), as reflected in Exhibit A-33, Schedule X-7. The rates
16 are unchanged from what was approved in Case No. U-21297 for the 2025 IRM
17 Year and therefore not included in the exhibit. Plan Years 2026 and 2027 reflect
18 the updated IRM proposal and associated revenue requirement as described by
19 Company Witness Foley.

20

21

Other Tariff Changes

22 **Q80. What does Exhibit A-16, Schedule F8 show?**

23 A80. This exhibit contains the proposed residential rate and tariff sheet changes which
24 result from the pricing changes and other proposals described above and additional
25 proposals described below.

Line
No.

1 **Q81. Are you sponsoring any new tariff sheets?**

2 A81. Yes. As described in the preceding testimony, I am sponsoring new tariff sheets for
3 proposed Rate Schedules D3.11 and D14.

4

5 **Q82. Are you proposing any changes to residential tariff credit language?**

6 A82. Yes, as described previously in my testimony, I am proposing the following
7 changes to the residential tariffs:

- 8 • Expansion of the low-income assistance (LIA) credit to all residential base rates
- 9 • Increase of the LIA credit from \$40 to \$50 as supported by Company Witness
10 Sparks

11

12 **Q83. Are you proposing any updates to the Contribution in Aid of Construction**
13 **(CIAC) standard allowance table?**

14 A83. Yes. I am proposing updates to the CIAC standard allowance table for customers
15 with new or expanded load greater than 1000 kW consistent with the method
16 approved in Case No. U-20836 and consistent with the Commission's Order in Case
17 No. U-21297, which required the Company to propose updated per foot
18 construction costs in this case. Those changes are included in Exhibit A-16,
19 Schedule F8, Section C6 and supported by Company Witness Hill. The standard
20 allowance table can be found in Exhibit A-16, Schedule F8, Section C6.2.

21

22 **Q84. Are you proposing any other changes to the Company's rate book?**

23 A84. Yes.

- 24 • I am proposing to eliminate Section C6.1(16) of the Company's rate book,
25 which is the waiver of CIAC for certain customers participating in the

Line
No.

1 Company's Charging Forward program. This change is supported by
2 Company Witness Bennett.

3 • I am proposing updates to Rate Schedules D1.1, D1.8, D3.3, and D5 as
4 supported by Company Witness Burgdorf.

5 • I am proposing to eliminate the tariff sheets for Rate Schedules D1-A and
6 D1-B. Both rates previously supported the Advanced Customer Pricing
7 Pilot and with the full transition to time of use now complete, these two
8 rates are obsolete.

9 • I am proposing to update the service territory map on page A-18.00 to better
10 reflect the Company's locations

11

12 **Q85. Does this conclude your testimony?**

13 A85. Yes.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

Case No. U-21534

EXHIBITS

OF

AARON WILLIS

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
R. A. Bellini
Page: 1 of 58

DTE Electric Company
Case No. U-21534
Present and Proposed Revenue

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Residential Service Rate Non-Transmitting Meter - D1

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 2 of 58

Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply						
1	Power Supply Charges						
2	Non-Capacity Charge	90,377	MWh	\$0.07809	7,058	\$0.06237	5,637
3	Capacity Charges:						
4	First 17 KWH/Day	50,492	MWh	\$0.01128	570	\$0.02932	1,480
5	Excess	39,884	MWh	\$0.01626	649	\$0.04227	1,686
6	Power Supply Subtotal	90,377	MWh	9.16¢	8,276	9.74¢	8,803
7							
8	PSCR	90,377	MWh	\$0.00000	0	\$0.00000	0
9	REPS	9,516	Meters	\$0.00000	0	\$0.00000	0
10	Total Full Service Power Supply	90,377	MWh	9.16¢	8,276	9.74¢	8,803
11							
12	Full Service Distribution	Quantity	Units				
13							
14	Service Charge	9,516	Cust.	\$8.50	971	\$8.50	971
15	Income Assistance	179	Cust.	(\$8.50)	(18)	(\$8.50)	(18)
16	Senior Citizen Provision	501	Cust.	(\$4.25)	(26)	(\$4.25)	(26)
17							
18	Distribution Charge	90,377	MWh	\$0.08137	7,354	\$0.09451	8,542
19	Distribution System	90,377	MWh	9.16¢	8,281	10.48¢	9,469
20	IRM	90,377	MWh	\$0.000941	85	\$0.000941	85
21	Nuclear Decomm.	90,377	MWh	\$0.000882	80	\$0.000882	80
22	Energy Waste Reduction	90,377	MWh	\$0.002552	231	\$0.002552	231
23	LIEAF	9,516	Cust.	\$0.88	100	\$0.88	100
24	Distribution Surcharges	90,377	MWh	0.55¢	496	0.55¢	496
25							
26	Total Full Service Distribution			9.71¢	8,777	11.03¢	9,965
27	Total Full Service D1	90,377	MWh	18.87¢	17,052	20.77¢	18,768
28							
29	Choice	Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
30							
31	Capacity Charges:						
32	First 17 KWH/Day	0	MWh	\$0.01128	0	\$0.02932	0
33	Excess	0	MWh	\$0.01626	0	\$0.04227	0
34	Capacity Total	0	MWh		0		0
35							
36	Distribution Charges						
37	Service Charge	0	Cust.	\$8.50	0	\$8.50	0
38	Income Assistance	0	Cust.	(\$8.50)	0	(\$8.50)	0
39	Senior Citizen Provision	0	Cust.	(\$4.25)	0	(\$4.25)	0
40							
41	Distribution Charge	0	MWh	\$0.08137	0	\$0.09451	0
42	Distribution System	0	MWh		0		0
43	IRM	0	MWh	\$0.000941	0	\$0.000941	0
44	Nuclear Decomm.	0	MWh	\$0.000882	0	\$0.000882	0
45	Energy Waste Reduction	0	MWh	\$0.002552	0	\$0.002552	0
46	LIEAF	0	Cust.	\$0.88	0	\$0.88	0
47	Distribution Surcharges	0	MWh		0		0
48							
49	Total Choice D1	0	MWh		0		0
50							
51	Total D1	90,377	MWh	18.87¢	17,052	20.77¢	18,768
52	Increase/Decrease (\$)						1,716

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Interruptible Space-Conditioning Service Rate - D1.1 Residential

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 3 of 58

Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply						
1	Power Supply Charges						
2	Non-Capacity Charge	321,827	MWh	\$0.06085	19,583	\$0.04870	15,672
3	Capacity Charges						
4	Summer Energy	300,672	MWh	\$0.01089	3,274	\$0.02799	8,414
5	Winter Winter	21,155	MWh	\$0.00270	57	\$0.00694	147
6	Power Supply Subtotal	321,827	MWh		22,915		24,233
7							
8	PSCR	321,827	MWh	\$0.00000	0	\$0.00000	0
9	Total Full Service Power Supply	321,827	MWh	7.12¢	22,915	7.53¢	24,233
10							
11	Full-Service Distribution	Quantity	Units				
12		Customers	Months				
13	Service Charge (June-Oct)	255,750	5	\$1.95	2,494	\$1.95	2,494
14							
15	Distribution Charge	321,827	MWh	\$0.08137	26,187	\$0.09451	30,417
16	Distribution System	321,827	MWh	8.91¢	28,681	10.23¢	32,910
17	IRM	321,827	MWh	\$0.000941	303	\$0.000941	303
18	Nuclear Decomm.	321,827	MWh	\$0.000882	284	\$0.000882	284
19	Energy Waste Reduction	321,827	MWh	\$0.002552	821	\$0.002552	821
20	Distribution Surcharges	321,827	MWh	0.44¢	1,408	0.44¢	1,408
21							
22	Total Full Service Distribution	321,827	MWh	9.35¢	30,089	10.66¢	34,318
23	Total Full-Service D1.1	321,827	MWh	16.47¢	53,003	18.19¢	58,552
24							
25	Choice	Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
26							
27	Capacity Charges						
28	Summer Energy	0	MWh	\$0.01089	0	\$0.02799	0
29	Winter Energy	0	MWh	\$0.00270	0	\$0.00694	0
30	Capacity Total	0	MWh		0		0
31							
32	Distribution Charges						
33		Customers	Months				
34	Service Charge (June-Oct)	0	5	\$1.95	0	\$1.95	0
35							
36	Distribution Energy	0	MWh	\$0.08137	0	\$0.09451	0
37	Distribution System	0	MWh		0		0
38	IRM	0	MWh	0.000941	0	0.000941	0
39	Nuclear Decomm.	0	MWh	\$0.000882	0	\$0.000882	0
40	Energy Waste Reduction	0	MWh	\$0.002552	0	\$0.002552	0
41	Distribution Surcharges	0	MWh		0		0
42							
43	Total Choice D1.1	0	MWh		0		0
44							
45	Total D1.1	321,827	MWh	16.47¢	53,003	18.19¢	58,552
46	Increase/Decrease (\$)						5,549

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Residential Service Rate Enhanced TOU - D1.2

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 4 of 58

Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply						
1	Power Supply Charges						
2	Non-Capacity Charge						
3	Summer:						
4	On-Peak	19,491	MWh	\$0.13949	\$2,719	\$0.11955	2,330
5	Off-Peak	58,273	MWh	\$0.04696	\$2,737	\$0.04025	2,345
6	Winter:						
7	On-Peak	26,292	MWh	\$0.11783	\$3,098	\$0.10098	2,655
8	Off-Peak	92,765	MWh	\$0.04512	\$4,186	\$0.03867	3,587
9	Capacity Charges						
10	Summer:						
11	On-Peak	19,491	MWh	\$0.01690	329	\$0.04474	872
12	Off-Peak	58,273	MWh	\$0.00569	332	\$0.01506	878
13	Winter:						
14	On-Peak	26,292	MWh	\$0.01427	375	\$0.03779	994
15	Off-Peak	92,765	MWh	\$0.00547	507	\$0.01447	1,343
16	Power Supply Subtotal	196,822	MWh		14,282		15,004
17							
18	PSCR	196,822	MWh	\$0.00000	0	\$0.00000	0
19	REPS	13,500	Meters	\$0.00000	0	\$0.00000	0
20	Total Full Service Power Supply	196,822	MWh	7.26¢	14,282	7.62¢	15,004
21							
22	Full Service Distribution	Quantity	Units				
23							
24	Service Charge	13,500	Cust.	\$8.50	1,377	\$8.50	1,377
25	Income Assistance	113	Cust.	(\$8.50)	(12)	(\$8.50)	(12)
26	Senior Citizen Provision	350	Cust.	(\$4.25)	(18)	(\$4.25)	(18)
27							
28	Distribution Energy	196,822	MWh	\$0.08137	16,015	\$0.09451	18,602
29	Distribution System	196,822	MWh	8.82¢	17,363	10.14¢	19,950
30	IRM	196,822	MWh	\$0.000941	185	\$0.000941	185
31	Nuclear Decomm.	196,822	MWh	\$0.000882	174	\$0.000882	174
32	Energy Waste Reduction	196,822	MWh	\$0.002552	502	\$0.002552	502
33	LIEAF	13,500	Cust.	\$0.88	143	\$0.88	143
34	Distribution Surcharges	196,822	MWh	0.51¢	1,004	0.51¢	1,004
35							
36	Total Full Service Distribution	196,822	MWh	9.33¢	18,367	10.65¢	20,954
37	Total Full-Service D1.2	196,822	MWh	16.59¢	32,649	18.27¢	35,957
38							
39	Choice	Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
40							
41	Capacity Charges						
42	Summer:						
43	On-Peak	0	MWh	\$0.01690	0	\$0.04474	0
44	Off-Peak	0	MWh	\$0.00569	0	\$0.01506	0
45	Winter:						
46	On-Peak	0	MWh	\$0.01427	0	\$0.03779	0
47	Off-Peak	0	MWh	\$0.00547	0	\$0.01447	0
48	Capacity Total	0	MWh		0		0
49							
50	Service Charge	0	Cust.	\$8.50	0	\$8.50	0
51	Income Assistance	0	Cust.	(\$8.50)	0	(\$8.50)	0
52	Senior Citizen Provision		Cust.	(\$4.25)	0	(\$4.25)	0
53							
54	Distribution Charge	0	MWh	\$0.08137	0	\$0.09451	0
55	Distribution System	0	MWh		0		0
56	IRM	0	MWh	\$0.000941	0	\$0.000941	0
57	Nuclear Decomm.	0	MWh	\$0.000882	0	\$0.000882	0
58	Energy Waste Reduction	0	MWh	\$0.002552	0	\$0.002552	0
59	LIEAF	0	Cust.	\$0.88	0	\$0.88	0
60	Distribution Surcharges	0	MWh		0		0
61							
62	Total Choice D1.2	0	MWh		0		0
63							
64	Total D1.2	196,822	MWh	16.59¢	32,649	18.27¢	35,957
65	Increase/Decrease (\$)						3,308

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Residential Service Special Low Income Pilot Rate - D1.6

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 5 of 58

Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d)	(e) Proposed	(f)
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply						
1	Power Supply Charges						
2	Non-Capacity Charge	242,162	MWh	\$0.07809	18,910	\$0.06237	15,105
3	Capacity Charges						
4	First 17 KWH/Day	159,969	MWh	\$0.01128	1,804	\$0.02932	4,690
5	Excess	82,193	MWh	\$0.01626	1,336	\$0.04227	3,474
6	Power Supply Subtotal	242,162	MWh	9.11¢	22,051	9.61¢	23,269
7							
8	PSCR	242,162	MWh	\$0.00000	0	\$0.00000	0
9	REPS	32,000	Meters	\$0.00000	0	\$0.00000	0
10	Total Full Service Power Supply	242,162	MWh	9.11¢	22,051	9.61¢	23,269
11							
12	Full Service Distribution	Quantity	Units				
13							
14	Service Charge	32,000	Cust.	\$8.50	3,264	\$8.50	3,264
15	Income Assistance	32,000	Cust.	(\$40.00)	(15,360)	(\$50.00)	(19,200)
16							
17	Distribution Charge	242,162	MWh	\$0.08137	19,705	\$0.09451	22,887
18	Distribution System	242,162	MWh	3.14¢	7,609	2.87¢	6,951
19	IRM	242,162	MWh	\$0.000941	228	\$0.000941	228
20	Nuclear Decomm.	242,162	MWh	\$0.000882	214	\$0.000882	214
21	Energy Waste Reduction	242,162	MWh	\$0.002552	618	\$0.002552	618
22	LIEAF	32,000	Cust.	\$0.88	338	\$0.88	338
23	Distribution Subtotal	242,162	MWh	0.58¢	1,397	0.58¢	1,397
24							
25	Total Full Service Distribution			3.72¢	9,006	3.45¢	8,349
26	Total Full Service D1.6	242,162	MWh	12.83¢	31,057	13.06¢	31,618
27							
28	Choice	Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
29							
30	Capacity Charges						
31	First 17 KWH/Day	0	MWh	\$0.01128	0	\$0.02932	0
32	Excess	0	MWh	\$0.01626	0	\$0.04227	0
33	Total Capacity	0			0		0
34							
35	Service Charge	0	Cust.	\$8.50	0	\$8.50	0
36	Income Assistance	0	Cust.	(\$40.00)	0	(\$50.00)	0
37							
38	Distribution Charge	0	MWh	\$0.08137	0	\$0.09451	0
39	Distribution System	0	MWh		0		0
40	IRM	0	MWh	0.000941	0	0.000941	0
41	Nuclear Decomm.	0	MWh	\$0.000882	0	\$0.000882	0
42	Energy Waste Reduction	0	MWh	\$0.002552	0	\$0.002552	0
43	LIEAF	0	Cust.	\$0.88	0	\$0.88	0
44	Distribution Subtotal	0	MWh		0		0
45							
46	Total Choice D1.6	0	MWh		0		0
47							
48	Total D1.6	242,162	MWh	12.83¢	31,057	13.06¢	31,618
49	Increase/Decrease (\$)						560

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Geothermal Time of Day Service Rate - Residential D1.7

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 6 of 58

Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply						
1	Power Supply Charges						
2	Non-Capacity Charge	108,929	MWh	\$0.04582	\$4,991		
3	Summer Energy (11 a.m. Peak Start)						
4	On-Peak	6,541	MWh			\$0.09310	609
5	Off-Peak	15,676	MWh			\$0.03084	483
6	Winter Energy (11 a.m. Peak Start)						
7	On-Peak	17,639	MWh			\$0.04023	710
8	Off-Peak	69,072	MWh			\$0.03161	2,183
9							
10	Capacity Charges:						
11	Summer Energy (11 a.m. Peak Start)						
12	On-Peak	6,541	MWh	\$0.04248	\$278	\$0.05086	333
13	Off-Peak	15,676	MWh	\$0.00001	\$0	\$0.01685	264
14	Winter Energy (11 a.m. Peak Start)						
15	On-Peak	17,639	MWh	\$0.01717	\$303	\$0.02197	388
16	Off-Peak	69,072	MWh	\$0.00369	\$255	\$0.01727	1,193
17	Power Supply Subtotal	108,929	MWh		\$5,827		6,162
18							
19	PSCR	108,929	MWh	\$0.00000	0	\$0.00000	0
20	Total Power Supply	108,929	MWh	5.35¢	5,827	5.66¢	6,162
21							
22	Full Service Distribution	Quantity	Units				
23							
24	Service Charge (\$/day)	8,160	Cust.	\$0.067	200	\$0.067	200
25							
26	Distribution Charge	108,929	MWh	\$0.08137	8,864	\$0.09451	10,295
27	Distribution System	108,929	MWh	8.32¢	9,063	9.63¢	10,495
28	IRM	108,929	MWh	\$0.000941	103	\$0.000941	103
29	Nuclear Decomm.	108,929	MWh	\$0.000882	96	\$0.000882	96
30	Energy Waste Reduction	108,929	MWh	\$0.002552	278	\$0.002552	278
31	Distribution Surcharges	108,929	MWh	0.44¢	477	0.44¢	477
32							
33	Total Full Service Distribution	108,929	MWh	8.76¢	9,540	10.07¢	10,971
34	Total Full-Service D1.7	108,929	MWh	14.11¢	15,366	15.73¢	17,134
35							
36	Choice	Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
37							
38	Capacity Charges:						
39	Summer Energy (11 a.m. Peak Start)						
40	On-Peak	0	MWh	\$0.04248	0	\$0.05086	0
41	Off-Peak	0	MWh	\$0.00001	0	\$0.01685	0
42	Winter Energy (11 a.m. Peak Start)						
43	On-Peak	0	MWh	\$0.01717	0	\$0.02197	0
44	Off-Peak	0	MWh	\$0.00369	0	\$0.01727	0
45	Total Capacity	0	MWh		0		0
46							
47	Distribution Charges						
48	Service Charge (\$/day)	0	Cust.	\$0.067	0	\$0.067	0
49							
50	Distribution Charge	0	MWh	\$0.08137	0	\$0.09451	0
51	Distribution System	0	MWh		0		0
52	IRM	0	MWh	\$0.000941	0	\$0.000941	0
53	Nuclear Decomm.	0	MWh	\$0.000882	0	\$0.000882	0
54	Energy Waste Reduction	0	MWh	\$0.002552	0	\$0.002552	0
55	Distribution Surcharges	0	MWh		0		0
56							
57	Total Choice D1.7	0	MWh		0		0
58							
59	Total D1.7	108,929	MWh	14.11¢	15,366	15.73¢	17,134
60	Increase/Decrease (\$)						1,767

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Residential Service Rate Dynamic Peak Pricing - D1.8

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 7 of 58

Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
1	Full Service Power Supply						
1	Non-Capacity Charge						
2	Off-Peak (11pm-7am)	87,291	MWh	\$0.03940	3,439	\$0.03098	2,704
3	Mid-Peak (7pm-11pm, 7am-3pm)	57,481	MWh	\$0.07635	4,389	\$0.06004	3,451
4	On-Peak (3pm-7pm)	21,918	MWh	\$0.14747	3,232	\$0.11702	2,565
5	Critical Peak (3pm-7pm)	83	MWh	\$0.14747	12	\$0.11702	10
6	Capacity Charges:						
7	Off-Peak (11pm-7am)	87,291	MWh	\$0.00590	515	\$0.01678	1,465
8	Mid-Peak (7pm-11pm, 7am-3pm)	57,481	MWh	\$0.01144	658	\$0.03252	1,869
9	On-Peak (3pm-7pm)	21,918	MWh	\$0.02067	453	\$0.06229	1,365
10	Critical Peak (3pm-7pm)	83	MWh	\$0.80253	67	\$0.83298	69
11	Power Supply Subtotal	166,773	MWh	\$0.07654	12,765	\$0.08095	13,500
12							
13	PSCR	166,773	MWh	\$0.00000	0	\$0.00000	0
14	REPS	21,200	Cust	\$0.00000	0	\$0.00000	0
15	Total Full Service Power Supply	166,773	MWh	7.65¢	12,765	8.09¢	13,500
16							
17	Full Service Distribution	Quantity	Units				
18							
19	Sales Applied to Min.		MWh				
20	Service Charge	21,200	Cust.	\$8.50	2,162	\$8.50	2,162
21	Income Assistance	1,416	Cust.	(\$8.50)	(144)	(\$8.50)	(144)
22	Senior Citizen Provision	549	Cust.	(\$4.25)	(28)	(\$4.25)	(28)
23							
24	Distribution Charge	166,773	MWh	\$0.08137	13,570	\$0.09451	15,762
25	Distribution System	166,773	MWh	9.33¢	15,560	10.64¢	17,752
26	IRM	166,773	MWh	\$0.000941	157	\$0.000941	157
27	Nuclear Decomm.	166,773	MWh	\$0.000882	147	\$0.000882	147
28	Energy Waste Reduction	166,773	MWh	\$0.002552	426	\$0.002552	426
29	LIEAF	21,200	cust	\$0.88	224	\$0.88	224
30	Distribution Surcharges	166,773	MWh	0.57¢	954	0.57¢	954
31							
32	Total Full Service Distribution			9.90¢	16,514	11.22¢	18,706
33	Total Full Service D1.8	166,773	MWh	17.56¢	29,279	19.31¢	32,205
34	Increase/Decrease (\$)						2,927

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Residential Electric Vehicle Rate - D1.9

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 8 of 58

Line No.	(a) Description	(b) Billing Determinants	(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply					
1	Power Supply Charges					
2	Non-Capacity Charge	12,539 MWh				
3	On-Peak	2,063 MWh	\$0.14635	302	\$0.11700	241
4	Off-Peak	10,477 MWh	\$0.03657	383	\$0.02924	306
5	Capacity Charge					
6						
7	On-Peak	2,063 MWh	\$0.02470	51	\$0.06387	132
8	Off-Peak	10,477 MWh	\$0.00618	65	\$0.01598	167
9		12,539 MWh				
10						
11	PSCR	12,539 MWh	\$0.00000	0	\$0.00000	0
12	Total Full Service Power Supply	12,539 MWh	6.39¢	801	6.75¢	847
13						
14	Full Service Distribution	Quantity Units				
15						
16	Service Charge (\$/month)	4,978 Cust.	\$1.95	116	\$1.95	116
17						
18	Distribution Charge	12,539 MWh	\$0.08137	1,020	\$0.09451	1,185
19	Distribution System	12,539 MWh	9.07¢	1,137	10.38¢	1,302
20	IRM	12,539 MWh	\$0.000941	12	\$0.000941	12
21	Nuclear Decomm.	12,539 MWh	\$0.000882	11	\$0.000882	11
22	Energy Waste Reduction	12,539 MWh	\$0.002552	32	\$0.002552	32
23	Distribution Surcharges	12,539 MWh	0.44¢	55	0.44¢	55
24						
25	Total Full Service Distribution	12,539 MWh	9.50¢	1,192	10.82¢	1,356
26	Total Full Service D1.9	12,539 MWh	15.89¢	1,992	17.57¢	2,203
27						
28	Choice	Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
29						
30	Capacity Charge					
31						
32	On-Peak	0 MWh	\$0.02470	0	\$0.06387	0
33	Off-Peak	0 MWh	\$0.00618	0	\$0.01598	0
34	Total Capacity	0 MWh		0		0
35						
36	Distribution Charges					
37	Service Charge (\$/month)	0 Cust.	\$1.95	0	\$1.95	0
38						
39	Distribution Charge	0 MWh	\$0.08137	0	\$0.09451	0
40	Distribution System	0 MWh		0		0
41	IRM	0 MWh	\$0.000941	0	\$0.000941	0
42	Nuclear Decomm.	0 MWh	\$0.000882	0	\$0.000882	0
43	Energy Waste Reduction	0 MWh	\$0.002552	0	\$0.002552	0
44	Distribution Surcharges	0 MWh		0		0
45						
46	Total Choice D1.9	0 MWh		0		0
47						
48	Total D1.9	12,539 MWh	15.89¢	1,992	17.57¢	2,203
49	Increase/Decrease (\$)					211

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Residential Service Rate Standard TOU - D1.11

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 9 of 58

Line No.	(a) Description	(b) Billing Determinants		(c) Present		(d)	(e) Proposed		(f)
		Quantity	Units	Rate	Revenue (\$000)		Rate	Revenue (\$000)	
	Full Service Power Supply								
1	Power Supply Charges								
2	Non-Capacity Charges								
3	June - September								
4	On Peak (3pm-7pm, M-F)	887,019	MWh	\$0.12201	108,225		\$0.09748	86,470	
5	Off Peak	4,534,773	MWh	\$0.07354	333,487		\$0.05873	266,321	
6	October - May								
7	On Peak (3pm-7pm, M-F)	1,077,809	MWh	\$0.08518	91,808		\$0.06875	74,094	
8	Off Peak	7,248,881	MWh	\$0.07354	533,083		\$0.05873	425,717	
9	Capacity Charges:								
10	June - September								
11	On Peak (3pm-7pm, M-F)	887,019	MWh	\$0.02060	18,273		\$0.05325	47,236	
12	Off Peak	4,534,773	MWh	\$0.01241	56,277		\$0.03208	145,484	
13	October - May								
14	On Peak (3pm-7pm, M-F)	1,077,809	MWh	\$0.01438	15,499		\$0.03755	40,476	
15	Off Peak	7,248,881	MWh	\$0.01241	89,959		\$0.03208	232,558	
16									
17	Power Supply Subtotal	13,748,482	MWh	9.07¢	1,246,609		9.59¢	1,318,355	
18									
19	PSCR	13,748,482	MWh	\$0.00000	0		\$0.00000	0	
20	REPS	1,968,733	Meters	\$0.00000	0		\$0.00000	0	
21	Total Full Service Power Supply	13,748,482	MWh	9.07¢	1,246,609		9.59¢	1,318,355	
22									
23	Full Service Distribution	Quantity	Units						
24									
25	Service Charge	1,968,733	Cust.	\$8.50	200,811		\$8.50	200,811	
26	Income Assistance	80,064	Cust.	(\$8.50)	(8,167)		(\$8.50)	(8,167)	
27	Senior Citizen Provision	102,050	Cust.	(\$4.25)	(5,205)		(\$4.25)	(5,205)	
28									
29	Distribution Charge	13,748,482	MWh	\$0.08137	1,118,714		\$0.09451	1,299,413	
30	Distribution System	13,748,482	MWh	9.50¢	1,306,154		10.81¢	1,486,853	
31	IRM	13,748,482	MWh	\$0.000941	12,937		\$0.000941	12,937	
32	Nuclear Decomm.	13,748,482	MWh	\$0.000882	12,126		\$0.000882	12,126	
33	Energy Waste Reduction	13,748,482	MWh	\$0.002552	35,086		\$0.002552	35,086	
34	LIEAF	1,968,733	Cust.	\$0.88	20,790		\$0.88	20,790	
35	Distribution Surcharges	13,748,482	MWh	0.59¢	80,939		0.59¢	80,939	
36									
37	Total Full Service Distribution			10.09¢	1,387,093		11.40¢	1,567,792	
38	Total Full Service D1.11	13,748,482	MWh	19.16¢	2,633,702		20.99¢	2,886,147	
39									
40	Choice	Quantity	Units	Rate	Revenue (\$000)		Rate	Revenue (\$000)	
41									
42	Capacity Charges:								
43	June - September								
44	On Peak (3pm-7pm, M-F)	0	MWh	\$0.02060	0		\$0.05325	0	
45	Off Peak	0	MWh	\$0.01241	0		\$0.03208	0	
46	October - May								
47	On Peak (3pm-7pm, M-F)	0	MWh	\$0.01438	0		\$0.03755	0	
48	Off Peak	0	MWh	\$0.01241	0		\$0.03208	0	
49									
50	Capacity Total	0	MWh		0			0	
51									
52	Distribution Charges								
53	Service Charge	0	Cust.	\$8.50	0		\$8.50	0	
54	Income Assistance	0	Cust.	(\$8.50)	0		(\$8.50)	0	
55	Senior Citizen Provision	0	Cust.	(\$4.25)	0		(\$4.25)	0	
56									
57	Distribution Charge	0	MWh	\$0.08137	0		\$0.09451	0	
58	Distribution System	0	MWh		0			0	
59	IRM	0	MWh	0.000941	0		0.000941	0	
60	Nuclear Decomm.	0	MWh	\$0.000882	0		\$0.000882	0	
61	Energy Waste Reduction	0	MWh	\$0.002552	0		\$0.002552	0	
62	LIEAF	0	Cust.	\$0.88	0		\$0.88	0	
63	Distribution Surcharges	0	MWh		0			0	
64									
65	Total Choice D1.11	0	MWh		0			0	
66									
67	Total D1.11	13,748,482	MWh	19.16¢	2,633,702		20.99¢	2,886,147	
68	Increase/Decrease (\$)							252,445	

Line No.	(a) Description	(b) Billing Determinants		(c) Proposed D1.11 Rates	(d) Revenue	(e) Revenue Neutral Design	(f) Revenue
		Quantity	Units	Rate	(Revenue (\$000))	Rate	(Revenue (\$000))
	Full Service Power Supply						
1	Power Supply Charges						
2	Non-Capacity Charge						
3	June - September						
4	On Peak (3pm-7pm, M-F)	881,337	MWh			\$0.10846	95,590
5	Off Peak (7am-3pm & 7pm-1am M-F; 7am-1am weekend)	3,561,782	MWh			\$0.07298	259,947
6	Super Off Peak (1am-7am)	978,673	MWh			\$0.04609	45,111
7	October - May						
8	On Peak (3pm-7pm, M-F)	1,067,922	MWh			\$0.06186	66,066
9	Off Peak (7am-3pm & 7pm-1am M-F; 7am-1am weekend)	5,439,585	MWh			\$0.05552	302,032
10	Super Off Peak (1am-7am)	1,819,184	MWh			\$0.04609	83,854
11	Capacity Charges:						
12	June - September						
13	On Peak (3pm-7pm, M-F)	881,337	MWh			\$0.05925	52,218
14	Off Peak (7am-3pm & 7pm-1am M-F; 7am-1am weekend)	3,561,782	MWh			\$0.03987	142,002
15	Super Off Peak (1am-7am)	978,673	MWh			\$0.02518	24,643
16	October - May						
17	On Peak (3pm-7pm, M-F)	1,067,922	MWh			\$0.03379	36,090
18	Off Peak (7am-3pm & 7pm-1am M-F; 7am-1am weekend)	5,439,585	MWh			\$0.03033	164,992
19	Super Off Peak (1am-7am)	1,819,184	MWh			\$0.02518	45,807
20	Power Supply Subtotal	13,748,482	MWh	9.59¢	1,318,355		1,318,355
21							
22	PSCR	13,748,482	MWh	\$0.00000	0	\$0.00000	0
23	REPS	1,968,733	Meters	\$0.00000	0	\$0.00000	0
24	Total Full Service Power Supply	13,748,482	MWh	9.59¢	1,318,355	9.59¢	1,318,355
25							
26	Full Service Distribution	Quantity	Units				
27							
28	Service Charge	1,968,733	Cust.			\$8.50	200,811
29	Income Assistance	80,064	Cust.			(\$8.50)	(8,167)
30	Senior Citizen Provision	102,050	Cust.			(\$4.25)	(5,205)
31							
32							
33							
34	Distribution Charge	13,748,482	MWh				
35	June - September						
36	On Peak (3pm-7pm, M-F)	881,337	MWh			\$0.19036	167,775
37	Off Peak (7am-3pm & 7pm-1am M-F; 7am-1am weekend)	3,561,782	MWh			\$0.14277	508,526
38	Super Off Peak (1am-7am)	978,673	MWh			\$0.04759	46,576
39	October - May						
40	On Peak (3pm-7pm, M-F)	1,067,922	MWh			\$0.09518	101,647
41	Off Peak (7am-3pm & 7pm-1am M-F; 7am-1am weekend)	5,439,585	MWh			\$0.07139	388,313
42	Super Off Peak (1am-7am)	1,819,184	MWh			\$0.04759	86,577
43	Distribution System	13,748,482	MWh	10.81¢	1,486,853	10.81¢	1,486,853
44	IRM	13,748,482	MWh	\$0.000941	12,937	\$0.000941	12,937
45	Nuclear Decomm.	13,748,482	MWh	\$0.000882	12,126	\$0.000882	12,126
46	Energy Waste Reduction	13,748,482	MWh	\$0.002552	35,086	\$0.002552	35,086
47	LIEAF	1,968,733	Cust.	\$0.88	20,790	\$0.88	20,790
48	Distribution Surcharges	13,748,482	MWh	0.59¢	80,939	0.59¢	80,939
49							
50	Total Full Service Distribution			11.40¢	1,567,792	11.40¢	1,567,792
51	Total Full Service D1.13	13,748,482	MWh	20.99¢	2,886,147	20.99¢	2,886,147
52							
53	Choice	Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
54							
55	Capacity Charges:						
56	June - September						
57	On Peak (3pm-7pm, M-F)	0	MWH			\$0.05925	0
58	Off Peak (7am-3pm & 7pm-1am M-F; 7am-1am weekend)	0	MWH			\$0.03987	0
59	Super Off Peak (1am-7am)	0	MWH			\$0.02518	0
60	October - May						
61	On Peak (3pm-7pm, M-F)	0	MWH			\$0.03379	0
62	Off Peak (7am-3pm & 7pm-1am M-F; 7am-1am weekend)	0	MWH			\$0.03033	0
63	Super Off Peak (1am-7am)	0	MWH			\$0.02518	0
64	Capacity Total	0	MWh		0		0
65							
66	Distribution Charges						
67	Service Charge	0	Cust.		0	\$8.50	0
68	Income Assistance	0	Cust.		0	(\$8.50)	0
69	Senior Citizen Provision	0	Cust.		0	(\$4.25)	0
70							
71	Distribution Charge						
72	June - September						
73	On Peak (3pm-7pm, M-F)	0	MWH			\$0.19036	0
74	Off Peak (7am-3pm & 7pm-1am M-F; 7am-1am weekend)	0	MWH			\$0.14277	0
75	Super Off Peak (1am-7am)	0	MWH			\$0.04759	0
76	October - May						
77	On Peak (3pm-7pm, M-F)	0	MWH			\$0.09518	0
78	Off Peak (7am-3pm & 7pm-1am M-F; 7am-1am weekend)	0	MWH			\$0.07139	0
79	Super Off Peak (1am-7am)	0	MWh		0	\$0.04759	0
80	Distribution System	0	MWh		0		0
81	IRM	0	MWh	\$0.000941	0	\$0.000941	0
82	Nuclear Decomm.	0	MWh	\$0.000882	0	\$0.000882	0
83	Energy Waste Reduction	0	MWh	\$0.002552	0	\$0.002552	0
84	LIEAF	0	Cust.	\$0.88	0	\$0.88	0
85	Distribution Surcharges	0	MWh		0		0
86							
87	Total Choice D1.13	0	MWh		0		0
88							
89	Total D1.13	13,748,482	MWh	20.99¢	2,886,147	20.99¢	2,886,147

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Residential Space Heating Rate - D2

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 11 of 58

Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply						
1	Power Supply Charges						
2	Non-Capacity Charge	282,672	MWh	\$0.06274	17,735	\$0.05498	15,542
3	Capacity Charges						
4	Summer						
5	First 17 KWH/Day	56,257	MWh	\$0.01059	596	\$0.02817	1,585
6	Excess	29,544	MWh	\$0.01514	447	\$0.04027	1,190
7	Winter						
8	First 20 KWH/Day	102,530	MWh	\$0.00624	640	\$0.01660	1,702
9	Excess	94,341	MWh	\$0.00244	230	\$0.00649	612
10							
11	PSCR	282,672	MWh	\$0.00000	0	\$0.00000	0
12	REPS	29,878	Meters	\$0.00000	0	\$0.00000	0
13	Total Full Service Power Supply	282,672	MWh	6.95¢	19,648	7.30¢	20,630
14							
15	Full Service Distribution	Quantity	Units				
16							
17	Service Charge	29,878	Cust.	\$8.50	3,048	\$8.50	3,048
18	Income Assistance	1,228	Cust.	(\$8.50)	(125)	(\$8.50)	(125)
19	Senior Citizen Provision	774	Cust.	(\$4.25)	(39)	(\$4.25)	(39)
20							
21	Distribution Charge						
22	Summer	85,801	MWh	\$0.08137	6,982	\$0.09451	8,109
23	Winter	196,871	MWh	\$0.08137	16,019	\$0.09451	18,607
24	Distribution System	282,672	MWh	9.16¢	25,884	10.47¢	29,599
25	IRM	282,672	MWh	\$0.000941	266	\$0.000941	266
26	Nuclear Decomm.	282,672	MWh	\$0.000882	249	\$0.000882	249
27	Energy Waste Reduction	282,672	MWh	\$0.002552	721	\$0.002552	721
28	LIEAF	29,878	Cust.	\$0.88	316	\$0.88	316
29	Distribution Surcharges	282,672	MWh	0.55¢	1,552	0.55¢	1,552
30							
31	Total Full Service Distribution	282,672	MWh	9.71¢	27,436	11.02¢	31,151
32	Total Full Service D2	282,672	MWh	16.66¢	47,084	18.32¢	51,782
33							
34	Choice	Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
35							
36	Capacity Charges						
37	Summer						
38	First 17 KWH/Day	0	MWh	\$0.01059	0	\$0.02817	0
39	Excess	0	MWh	\$0.01514	0	\$0.04027	0
40	Winter						
41	First 20 KWH/Day	0	MWh	\$0.00624	0	\$0.01660	0
42	Excess	0	MWh	\$0.00244	0	\$0.00649	0
43	Total Capacity				0		0
44							
45	Distribution Charges						
46	Service Charge	0	Cust.	\$8.50	0	\$8.50	0
47	Income Assistance	0	Cust.	(\$8.50)	0	(\$8.50)	0
48	Senior Citizen Provision		Cust.	(\$4.25)	0	(\$4.25)	0
49							
50	Distribution Charge						
51	Summer	0	MWh	\$0.08137	0	\$0.09451	0
52	Winter	0	MWh	\$0.08137	0	\$0.09451	0
53	Distribution System	0	MWh		0		0
54	IRM	0	MWh	\$0.000941	0	\$0.000941	0
55	Nuclear Decomm.	0	MWh	\$0.000882	0	\$0.000882	0
56	Energy Waste Reduction	0	MWh	\$0.002552	0	\$0.002552	0
57	LIEAF	0	Cust.	\$0.88	0	\$0.88	0
58	Distribution Surcharges	0	MWh		0		0
59							
60	Total Choice D2	0	MWh		0		0
61							
62	Total D2	282,672	MWh	16.66¢	47,084	18.32¢	51,782
63	Increase/Decrease (\$)						4,698

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Water Heating Service Rate - Residential D5

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 12 of 58

Line No.	(a) Description	(b) Billing Determinants	(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply					
1	Non-Capacity Charge	97,669 MWh	\$0.04132	4,036	\$0.03303	3,226
2	Capacity Charge	97,669 MWh	\$0.00698	682	\$0.01805	1,763
3						
4	PSCR	97,669 MWh	\$0.00000	0	\$0.00000	0
5	Total Full Service Power Supply	97,669 MWh	4.83¢	4,717	5.11¢	4,989
6						
7	Full-Service Distribution	Quantity Units				
8						
9	Service Charge	45,020 Cust.	\$1.95	1,053	\$1.95	1,053
10						
11	Distribution Charge	97,669 MWh	\$0.08137	7,947	\$0.09451	9,231
12	Distribution System	97,669 MWh	9.22¢	9,001	10.53¢	10,285
13	IRM	97,669 MWh	\$0.000941	92	\$0.000941	92
14	Nuclear Decomm.	97,669 MWh	\$0.000882	86	\$0.000882	86
15	Energy Waste Reduction	97,669 MWh	\$0.002552	249	\$0.002552	249
16	Distribution Surcharges	97,669 MWh	0.44¢	427	0.44¢	427
17						
18	Total Full Service Distribution	97,669 MWh	9.65¢	9,428	10.97¢	10,712
19	Total Full Service D5	97,669 MWh	14.48¢	14,146	16.08¢	15,701
20						
21	Choice	Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
22						
23	Capacity Charge	0 MWh	\$0.00698	0	\$0.01805	0
24	Total Capacity	0		0		0
25						
26	Distribution Charges					
27	Service Charge	0 Cust.	\$1.95	0	\$1.95	0
28						
29	Distribution Charge	0 MWh	\$0.08137	0	\$0.09451	0
30	Distribution System	0		0		0
31	IRM	0 MWh	\$0.000941	0	\$0.000941	0
32	Nuclear Decomm.	0 MWh	\$0.000882	0	\$0.000882	0
33	Energy Waste Reduction	0 MWh	\$0.002552	0	\$0.002552	0
34	Distribution Surcharges	0 MWh		0		0
35						
36	Total Choice Distribution D5	0 MWh		0		0
37						
38	Total D5	97,669 MWh	14.48¢	14,146	16.08¢	15,701
39	Increase/Decrease (\$)					1,555

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Interruptible Space Conditioning Service Rate - Commercial D1.1

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 13 of 58

Line No.	(a) Description	(b) Billing Determinants	(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply					
1	Capacity					
2	Energy					
3	Summer	3,490 MWh	\$0.01049	37	\$0.02713	95
4	Winter	1,662 MWh	\$0.00470	8	\$0.01215	20
5	Non-capacity energy	5,153	\$0.06077	313	\$0.05025	259
6	Power Supply Subtotal	5,153 MWh		358		374
7						
8	PSCR	5,153 MWh	\$0.00000	0	\$0.00000	0
9	REPS	800 Meters	\$0.00	0	\$0.00	0
10	Total Full Service Power Supply	5,153 MWh		6.94¢ 358		7.26¢ 374
11						
12	Full Service Distribution					
13						
14	Service Charge (June-Oct)	800 Cust.	\$1.95	8	\$1.95	8
15						
16	Distribution Charge	5,153 MWh	\$0.05288	272	\$0.06156	317
17	Distribution System	5,153 MWh	5.44¢	280	6.31¢	325
18	IRM	5,153 MWh	\$0.000595	3	\$0.000595	3
19	Nuclear Decomm.	5,153 MWh	\$0.000882	5	\$0.000882	5
20	Energy Waste Reduction	800 Meters	\$5.50	53	\$5.50	53
21	LIEAF	800 Meters	\$0.88	8	\$0.88	8
22	Distribution Surcharges	5,153 MWh	1.34¢	69	1.34¢	69
23						
24	Total Distribution	5,153 MWh		6.78¢ 349		7.64¢ 394
25	Total Full Service D1.1	5,153 MWh		13.71¢ 707		14.90¢ 768
26						
27	Choice Distribution	Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
28						
29	Capacity					
30	Energy					
31	Summer	0 MWh	\$0.01049	0	\$0.02713	0
32	Winter	0 MWh	\$0.00470	0	\$0.01215	0
33						
34	Service Charge (June-Oct)	8 Cust.	\$1.95	0	\$1.95	0
35						
36	Distribution Charge	11 MWh	\$0.05288	1	\$0.06156	1
37	Distribution System	11 MWh	5.99¢	1	6.86¢	1
38	IRM	11 MWh	0.000595	0	0.000595	0
39	Nuclear Decomm.	11 MWh	\$0.000882	0	\$0.000882	0
40	Energy Waste Reduction	8 Meters	\$5.50	1	\$5.50	1
41	LIEAF	8 Meters	\$0.88	0	\$0.88	0
42	Distribution Surcharges	11 MWh	5.64¢	1	5.64¢	1
43						
44	Total Choice D1.1	11 MWh		11.62¢ 1		12.49¢ 1
45						
46	Total D1.1	5,164 MWh		13.71¢ 708		14.89¢ 769
47	Increase/Decrease (\$)					61

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Commercial Geothermal Time of Day (D1.7)

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 14 of 58

Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d) Revenue	(e) Proposed	(f) Revenue
		Quantity	Units	Rate		Rate	
	Full Service Power Supply						
	Capacity Charges				(\$000)		(\$000)
1	Energy						
2	Summer (11 a.m. Peak Start)						
3	On-Peak	1,258	MWh	\$0.00893	11	\$0.01591	20
4	Off-Peak	2,843	MWh	\$0.00464	13	\$0.01453	41
5	Winter (11 a.m. Peak Start)						
6	On-Peak	2,799	MWh	\$0.00572	16	\$0.01488	42
7	Off-Peak	8,489	MWh	\$0.00572	49	\$0.01488	126
8							
9	Non-Capacity Energy	15,388	MWh	\$0.04059	625		
10	Summer (11 a.m. Peak Start)						
11	On-Peak	1,258	MWh			\$0.03586	45
12	Off-Peak	2,843	MWh			\$0.03276	93
13	Winter (11 a.m. Peak Start)						
14	On-Peak	2,799	MWh			\$0.03354	94
15	Off-Peak	8,489	MWh			\$0.03354	285
16	Power Supply Subtotal	15,388	MWh		714		746
17							
18	PSCR	15,388	MWh	\$0.00000	0	\$0.00000	0
19	REPS	198	Meters	\$0.00	0	\$0.00	0
20	Total Full Service Power Supply	15,388	MWh		4.64¢ 714		4.85¢ 746
21							
22	Full Service Distribution	Quantity	Units				
23							
24	Service Charge	198	Cust.	\$0.067	5	\$0.067	5
25							
26	Distribution Charge	15,388	MWh	\$0.05288	814	\$0.06156	947
27	Distribution System	15,388	MWh		5.32¢ 819		6.19¢ 952
28	IRM	15,388	MWh	\$0.000595	9	\$0.000595	9
29	Nuclear Decomm.	15,388	MWh	\$0.000882	14	\$0.000882	14
30	Energy Waste Reduction	198	Meters	\$5.50	13	\$5.50	13
31	LIEAF	198	Meters	\$0.88	2	\$0.88	2
32	Distribution Surcharges	15,388	MWh		0.25¢ 38		0.25¢ 38
33							
34	Total Distribution	15,388	MWh		5.57¢ 856		6.43¢ 990
35	Total Full Service D1.7	15,388	MWh		10.20¢ 1,570		11.28¢ 1,736
36							
37	Choice Distribution	Quantity	Units	Rate	Revenue	Rate	Revenue
38					(\$000)		(\$000)
39	Capacity Charges						
40	Energy						
41	Summer (11 a.m. Peak Start)						
42	On-Peak		MWh	\$0.00893	0	\$0.01591	0
43	Off-Peak		MWh	\$0.00464	0	\$0.01453	0
44	Winter (11 a.m. Peak Start)						
45	On-Peak		MWh	\$0.00572	0	\$0.01488	0
46	Off-Peak		MWh	\$0.00572	0	\$0.01488	0
47							
48	Service Charge	1	Cust.	\$0.067	0	\$0.067	0
49							
50	Distribution Charge	198	MWh	\$0.05288	10	\$0.06156	12
51	Distribution System	198	MWh		5.30¢ 11		6.17¢ 12
52	IRM	198	MWh	\$0.000595	0	\$0.000595	0
53	Nuclear Decomm.	198	MWh	\$0.000882	0	\$0.000882	0
54	Energy Waste Reduction	1	Meters	\$5.50	0	\$5.50	0
55	LIEAF	1	Meters	\$0.88	0	\$0.88	0
56	Distribution Surcharges	198	MWh		0.19¢ 0		0.19¢ 0
57							
58	Total Choice D1.7	198	MWh		5.49¢ 11		6.35¢ 13
59							
60	Total D1.7	15,586	MWh		10.14¢ 1,581		11.22¢ 1,749
61	Increase/Decrease (\$)						168

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Commercial Dynamic Peak Pricing Rate - D1.8

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 15 of 58

Line No.	(a) Description	(b) Billing Determinants	(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply					
	Capacity					
1	Energy					
2	Off-Peak (11pm-7am)	460 MWh	\$0.00570	3	\$0.01457	7
3	Mid-Peak (7 pm-11pm, 7am-3pm)	387 MWh	\$0.01119	4	\$0.02862	11
4	On-Peak (3 pm- 7 pm)	125 MWh	\$0.02062	3	\$0.05271	7
5	Critical Peak (3pm-7pm)	0 MWh	\$0.80517	0	\$0.82837	0
6						
7	Non-capacity energy	972 MWh				
8	Off-Peak (11pm-7am)	460 MWh	\$0.04002	18	\$0.03311	15
9	Mid-Peak (7 pm-11pm, 7am-3pm)	387 MWh	\$0.07863	30	\$0.06505	25
10	On-Peak (3 pm- 7 pm)	125 MWh	\$0.14483	18	\$0.12163	15
11	Critical Peak (3pm-7pm)	0 MWh	\$0.14483	0	\$0.12163	0
12	Power Supply Subtotal	972 MWh		77		80
13						
14	PSCR	972 MWh	\$0.00000	0	\$0.00000	0
15	REPS	28 Cust.	\$0.00	0	\$0.00	0
16	Total Full Service Power Supply	972 MWh	7.90¢	77	8.26¢	80
17						
18	Full Service Distribution	Quantity Units				
19						
20	Service Charge	28 Cust.	\$11.25	4	\$11.25	4
21						
22	Distribution Charge	972 MWh	\$0.05288	51	\$0.06156	60
23	Distribution System	972 MWh	5.68¢	55	6.55¢	64
24	IRM	972 MWh	\$0.000595	1	\$0.000595	1
25	Nuclear Decomm.	972 MWh	\$0.000882	1	\$0.000882	1
26	Energy Waste Reduction	28 Cust.	\$5.50	2	\$5.50	2
27	LIEAF	28	\$0.88	0	\$0.88	0
28	Distribution Surcharges	972 MWh	0.37¢	4	0.37¢	4
29	Total Full Service D1.1					
30	Total Full Service Distribution	972 MWh	6.04¢	59	6.91¢	67
31	Total Full Service D1.8	972 MWh	13.94¢	136	15.17¢	148
32	Increase/Decrease (\$)					12

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Commercial Electric Vehicle Rate - D1.9

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 16 of 58

Line No.	(a) Description	(b) Billing Determinants	(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply					
1	Power Supply Charges					
2	Capacity					
3	Option I					
4	On-Peak	105 MWh	\$0.02470	3	\$0.06387	7
5	Off-Peak	237 MWh	\$0.00618	1	\$0.01598	4
6		342 MWh				
7						
8	Non-capacity energy charge					
	On-Peak	105 MWh	\$0.14635	15	\$0.11700	12
	Off-Peak	237 MWh	\$0.03657	9	\$0.02924	7
9						
10	PSCR	342 MWh	\$0.00000	0	\$0.00000	0
11						
12						
13	Total Full Service Power Supply	342 MWh	8.20¢	28	8.67¢	30
14						
15	Full Service Distribution					
16						
17	Option I Service Charge (\$/month)	22 Cust.	\$1.95	1	\$1.95	1
18						
19	Distribution Charge	342 MWh	\$0.08137	28	\$0.09451	32
20	Distribution System	342 MWh	8.29¢	28	9.60¢	33
21	IRM	342 MWh	\$0.000595	0	\$0.000595	0
22	Nuclear Decomm.	342 MWh	\$0.000882	0	\$0.000882	0
23	Energy Waste Reduction	22 Meters	\$5.50	1	\$5.50	1
24	LIEAF	342 Meters	\$0.88	4	\$0.88	4
25	Distribution Surcharges	342 MWh	1.63¢	6	1.63¢	6
26						
27	Total Full Service Distribution	342 MWh	9.92¢	34	11.23¢	38
28	Total Full-Service D1.9	342 MWh	18.12¢	62	19.90¢	68
29						
30	Choice Distribution					
31						
32	Capacity					
33	Option I					
34	On-Peak	0 MWh	\$0.02470	0	\$0.06387	0
35	Off-Peak	0 MWh	\$0.00618	0	\$0.01598	0
36		0 MWh				
37	Option I Service Charge (\$/month)	0 Cust.	\$1.95	0	\$1.95	0
38						
39	Distribution Charge	0 MWh	\$0.08137	0	\$0.09451	0
40	Distribution System	0 MWh	0	0	0	0
41	IRM	0 MWh	\$0.000595	0	\$0.000595	0
42	Nuclear Decomm.	0 MWh	\$0.000882	0	\$0.000882	0
43	Energy Waste Reduction	0 Meters	\$5.50	0	\$5.50	0
44	LIEAF	0 Meters	\$0.880000	0	\$0.880000	0
45	Distribution Subtotal	0 MWh	0	0	0	0
46						
47						
48	Total Choice D1.9	0 MWh	0	0	0	0
49						
50	Total D1.9	342 MWh	18.12¢	62	19.90¢	68
51	Increase/Decrease (\$)					6

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
General Service Rate - D3

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 17 of 58

Line No.	(a) Description	(b) Billing Determinants	(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply					
1	Capacity					
2	Energy	7,457,882 MWh	\$0.01010	75,325	\$0.02605	194,249
3						
4	Non-Capacity					
5	Energy	7,457,882	\$0.07096	529,211	\$0.05870	437,812
6						
7	PSCR	7,457,882 MWh	\$0.00000	0	\$0.00000	0
8	REPS	197,670 Meters	\$0.00	0	\$0.00	0
9	Total Full Service Power Supply	7,457,882 MWh	8.11¢	604,536	8.48¢	632,062
10						
11	Full Service Distribution	Quantity Units				
12						
13	Service Charge	197,670 Cust.	\$11.25	26,685	\$11.25	26,685
14						
15	Distribution Charge	7,457,882 MWh	\$0.05288	394,373	\$0.06156	459,130
16	Distribution System	7,457,882 MWh	5.65¢	421,058	6.51¢	485,816
17	IRM	7,457,882 MWh	\$0.000595	4,437	\$0.000595	4,437
18	Nuclear Decomm.	7,457,882 MWh	\$0.000882	6,578	\$0.000882	6,578
19	Energy Optimization	197,670 Meters	\$5.50	13,046	\$5.50	13,046
20	LIEAF	197,670 Meters	\$0.88	2,087	\$0.88	2,087
21	Distribution Surcharges	7,457,882 MWh	0.35¢	26,149	0.35¢	26,149
22						
23	Total Full Service Distribution	7,457,882 MWh	6.00¢	447,207	6.86¢	511,965
24	Total Full Service D3	7,457,882 MWh	14.10¢	1,051,743	15.34¢	1,144,026
25						
26	Choice Distribution	Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
27						
28	Capacity					
29	Energy	0 MWh	\$0.01010	0	\$0.02605	0
30						
31	Service Charge	1,843 Cust.	\$11.25	249	\$11.25	249
32						
33	Distribution Charge	261,446 MWh	\$0.05288	13,825	\$0.06156	16,095
34	Distribution System	261,446 MWh	5.38¢	14,074	6.25¢	16,344
35	IRM	261,446 MWh	\$0.000595	156	\$0.000595	156
36	Nuclear Decomm.	261,446 MWh	\$0.000882	231	\$0.000882	231
37	Energy Optimization	1,843 Meters	\$5.50	122	\$5.50	122
38	LIEAF	1,843 Meters	\$0.88	19	\$0.88	19
39	Distribution Surcharges	261,446 MWh	0.20¢	527	0.20¢	527
40						
41	Total Choice D3	261,446 MWh	5.58¢	14,601	6.45¢	16,871
42						
43	Total D3	7,719,328 MWh	13.81¢	1,066,344	15.04¢	1,160,898
44	Increase/Decrease (\$)					94,553

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Unmetered General Service Rate - D3.1

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 18 of 58

Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
1	Connected Load	254,666,315	Watts				
2							
3	Capacity						
4	Energy	89,133	MWh	0.00848	756	0.02214	1,973
5							
6	Non-capacity energy	89,133	MWh	0.11247	10,025	0.11146	9,934
7							
8	PSCR	89,133	MWh	0.00000	0	0	0
9	IRM	89,133	MWh	0.000595	53	0.000595	53
10	Nuclear Decommissioning	89,133	MWh	0.000882	79	0.000882	79
11							
12	Energy Waste Reduction	2,300	Meters	5.50	152	5.50	152
13							
14	REPS	2,300	Meters	0.00	0	0.00	0
15							
16	Total D3.1	89,133	MWh		11,064		12,191
	Increase/Decrease (\$)						1,127

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Secondary Educational Institute - D3.2

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 19 of 58

Line No.	(a) Description	(b) Billing Determinants	(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply					
1	Capacity					
2	Energy	331,944 MWh	\$0.00939	3,117	\$0.02426	8,053
3						
4	Non-capacity energy	331,944 MWh	\$0.06937	23,027	\$0.05764	19,133
5						
6	PSCR	331,944 MWh	\$0.00000	0	\$0.00000	0
7	REPS	1,185 Meters	\$0.00	0	\$0.00	0
8	Total Full Service Power Supply	331,944 MWh	7.88¢	26,144	8.19¢	27,186
9						
10	Full Service Distribution	Quantity Units				
11						
12	Service Charge	1,185 Cust.	\$11.25	160	\$11.25	160
13						
14	Distribution Charge	331,944 MWh	\$0.05288	17,553	\$0.06156	20,435
15	Distribution System	331,944 MWh	5.34¢	17,713	6.20¢	20,595
16	IRM	331,944 MWh	\$0.000595	198	\$0.000595	198
17	Nuclear Decomm.	331,944 MWh	\$0.000882	293	\$0.000882	293
18	Energy Waste Reduction	1,185 Meters	\$5.50	78	\$5.50	78
19	LIEAF	1,185 Meters	\$0.88	13	\$0.88	13
20	Distribution Surcharges	331,944 MWh	0.18¢	581	0.18¢	581
21						
22	Total Full Service Distribution	331,944 MWh	5.51¢	18,294	6.38¢	21,176
23	Total Full Service D3.2	331,944 MWh	13.39¢	44,438	14.57¢	48,362
24						
25	Choice Distribution	Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
26						
27	Capacity					
28	Energy	0 MWh	\$0.00939	0	\$0.02426	0
29						
30	Service Charge	767 Cust.	\$11.25	104	\$11.25	104
31						
32	Distribution Charge	296,801 MWh	\$0.05288	15,695	\$0.06156	18,272
33	Distribution System	296,801 MWh	5.32¢	15,798	6.19¢	18,376
34	IRM	296,801 MWh	\$0.000595	177	\$0.000595	177
35	Nuclear Decomm.	296,801 MWh	\$0.000882	262	\$0.000882	262
36	Energy Waste Reduction	767 Meters	\$5.50	51	\$5.50	51
37	LIEAF	767 Meters	\$0.88	8	\$0.88	8
38	Distribution Surcharges	296,801 MWh	0.00¢	497	0.17¢	497
39						
40	Total Choice D3.2	296,801 MWh	5.49¢	16,296	6.36¢	18,873
41						
42	Total D3.2	628,745 MWh	9.66¢	60,733	10.69¢	67,235
43	Increase/Decrease (\$)					6,501

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Interruptible General Service Rate - D3.3

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 20 of 58

Line No.	(a) Description	(b) Billing Determinants	(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply					
1	Capacity					
2	Energy	54,552 MWh	\$0.00844	460	\$0.02176	1,187
3						
4	Non-capacity energy	54,552 MWh	\$0.05929	3,234	\$0.04905	2,676
5						
6	PSCR	54,552 MWh	\$0.00000	0	\$0.00000	0
7	REPS	64 Meters	\$0.00	0	\$0.00	0
8	Total Full Service Power Supply	54,552 MWh	6.77¢	3,695	7.08¢	3,863
9						
10	Full Service Distribution	Quantity Units				
11						
12	Service Charge	64 Cust.	\$11.25	9	\$11.25	9
13						
14	Distribution Charge	54,552 MWh	\$0.05288	2,885	\$0.06156	3,358
15	Distribution System	54,552 MWh	5.30¢	2,893	6.17¢	3,367
16	IRM	54,552 MWh	\$0.000595	32	\$0.000595	32
17	Nuclear Decomm.	54,552 MWh	\$0.000882	48	\$0.000882	48
18	Energy Waste Reduction	64 Meters	\$5.50	4	\$5.50	4
19	LIEAF	64 Meters	\$0.88	1	\$0.88	1
20	Distribution Surcharges	54,552 MWh	0.16¢	85	0.16¢	85
21						
22	Full Service Distribution	54,552 MWh	5.46¢	2,979	6.33¢	3,452
23	Total Full Service D3.3	54,552 MWh	12.23¢	6,674	13.41¢	7,316
24						
25	Choice Distribution	Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
26						
27	Capacity					
28	Energy	0 MWh	\$0.00844	0	\$0.02176	0
29						
30	Service Charge	4 Cust.	\$11.25	1	\$11.25	1
31						
32	Distribution Charge	7,513 MWh	\$0.05288	397	\$0.06156	463
33	Distribution System	7,513 MWh	5.30¢	398	6.16¢	463
34	IRM	7,513 MWh	0.000595	4	0.000595	4
35	Nuclear Decomm.	7,513 MWh	\$0.000882	7	\$0.000882	7
36	Energy Waste Reduction	4 Meters	\$5.50	0	\$5.50	0
37	LIEAF	4 Meters	\$0.88	0	\$0.88	0
38	Distribution Surcharges	7,513 MWh	0.15¢	11	0.15¢	11
39						
40	Total Choice D3.3	7,513 MWh	5.45¢	409	6.32¢	474
41						
42	Total D3.3	62,065 MWh	11.41¢	7,083	12.55¢	7,790
43	Increase/Decrease (\$)					707

**Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Company Owned Charging Service - D3.5**

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 21 of 58

[illegible]

Michigan Public Service Commission
DTE Electric Company
Optional TOU General Service Rate - D3.11
Designed Revenue Neutral to D3

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 22 of 58
Revised

Line	(a)	(b)	(c)	(d)	(e)	(f)
No.	Description	Billing Determinants <i>Revised</i>	Proposed D3	Revenue Neutral Design <i>Revised</i>		
		<u>Quantity</u> <u>Units</u>	<u>Rate</u> <u>Revenue</u> (\$000)	<u>Rate</u> <u>Revenue</u> (\$000)		
1	Full Service Power Supply					
2	Capacity					
3	June - September					
4	On Peak (1pm - 5pm M-F)	439,913 MWh		\$0.04173 18,356		
5	Off Peak	2,300,571 MWh		\$0.02489 57,254		
6	October - May					
7	On Peak (1pm - 5pm M-F)	711,494 MWh		\$0.02663 18,947		
8	Off Peak	4,005,903 MWh		\$0.02489 99,694		
9	Non-Capacity					
10	June - September					
11	On Peak (1pm - 5pm M-F)	439,913 MWh		\$0.09404 41,371		
12	Off Peak	2,300,571 MWh		\$0.05609 129,042		
13	October - May					
14	On Peak (1pm - 5pm M-F)	711,494 MWh		\$0.06002 42,703		
15	Off Peak	4,005,903 MWh		\$0.05609 224,696		
16						
17	PSCR	7,457,882 MWh		\$0.00000 0		
18	REPS	197,670 Meters		\$0.00 0		
19	Total Full Service Power Supply	7,457,882 MWh	8.48¢ 632,062	8.48¢ 632,062		
20						
21	Full Service Distribution	<u>Quantity</u> <u>Units</u>				
22						
23	Service Charge	197,670 Cust.	\$11.25 26,685	\$11.25 26,685		
24						
25	Distribution Charge	7,457,882 MWh	\$0.06156 459,130	\$0.06156 459,130		
26	Distribution System	7,457,882 MWh	6.51¢ 485,816	6.51¢ 485,816		
27	IRM	7,457,882 MWh	\$0.000595 4,437	\$0.000595 4,437		
28	Nuclear Decomm.	7,457,882 MWh	\$0.000882 6,578	\$0.000882 6,578		
29	Energy Optimization	197,670 Meters	\$5.50 13,046	\$5.50 13,046		
30	LIEAF	197,670 Meters	\$0.88 2,087	\$0.88 2,087		
31	Distribution Surcharges	7,457,882 MWh	0.35¢ 26,149	0.35¢ 26,149		
32						
33	Total Full Service Distribution	7,457,882 MWh	6.86¢ 511,965	6.86¢ 511,965		
34	Total Full Service D3.11	7,457,882 MWh	15.34¢ 1,144,026	15.34¢ 1,144,026		
35						
36	Choice Distribution	<u>Quantity</u> <u>Units</u>	<u>Rate</u> <u>Revenue</u> (\$000)	<u>Rate</u> <u>Revenue</u> (\$000)		
37						
38	Capacity					
39	June - September					
40	On Peak (1pm - 5pm M-F)	0 MWh		\$0.04173 0		
41	Off Peak	0 MWh		\$0.02489 0		
42	October - May					
43	On Peak (1pm - 5pm M-F)	0 MWh		\$0.02663 0		
44	Off Peak	0 MWh		\$0.02489 0		
45						
46	Service Charge	1,843 Cust.	\$11.25 249	\$11.25 249		
47						
48	Distribution Charge	261,446 MWh	\$0.06156 16,095	\$0.06156 16,095		
49	Distribution System	261,446 MWh	6.25¢ 16,344	6.25¢ 16,344		
50	IRM	261,446 MWh	\$0.000595 156	\$0.000595 156		
51	Nuclear Decomm.	261,446 MWh	\$0.000882 231	\$0.000882 231		
52	Energy Optimization	1,843 Meters	\$5.50 122	\$5.50 122		
53	LIEAF	1,843 Meters	\$0.88 19	\$0.88 19		
54	Distribution Surcharges	261,446 MWh	0.20¢ 527	0.20¢ 527		
55						
56	Total Choice D3.11	261,446 MWh	6.45¢ 16,871	6.45¢ 16,871		
57						
58	Total D3.11	7,719,328 MWh	15.04¢ 1,160,898	15.04¢ 1,160,898		
59	Increase/Decrease (\$)				-	

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Large General Service Rate - D4

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 23 of 58

Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d) Revenue (\$000)	(e) Proposed	(f) Revenue (\$000)
	Full Service Power Supply	<u>Quantity</u>	<u>Units</u>	<u>Rate</u>	<u>Revenue (\$000)</u>	<u>Rate</u>	<u>Revenue (\$000)</u>
1	Capacity						
2	Demand Charge	4,219,890	kW	\$3.57	15,065	\$9.18	38,720
3	Energy						
4	First 200 Hrs. Use	853,413	MWh	\$0.00000	0	\$0.00000	0
5	Excess	885,101	MWh	\$0.00000	0	\$0.00000	0
6	Power Supply Subtotal	1,738,514	MWh		15,065		38,720
7							
8	Non-capacity						
9	Demand Charge	4,219,890	kW	13.02	54,943	\$8.07	34,036
10	Energy						
11	First 200 Hrs. Use	853,413	MWh	0.04012	34,239	\$0.04169	35,583
12	Excess	885,101	MWh	0.03097	27,412	\$0.03219	28,488
13	PSCR	1,738,514	MWh	\$0.00000	0	\$0.00000	0
14	REPS	7,791	Meters	\$0.00	0	\$0.00	0
15	Total Full Service Power Supply	1,738,514	MWh	7.57¢	131,658	7.87¢	136,827
16							
17	Full Service Distribution	<u>Quantity</u>	<u>Units</u>				
18							
19	Service Charge	7,791	Cust.	\$13.67	1,278	\$13.67	1,278
20							
21	Distribution Demand Charge	4,219,890	kW	\$21.80	91,994	\$25.21	106,380
22	Distribution Energy Charge	1,738,514	MWh	\$0.000000	0	\$0.000000	0
23	Distribution Charges	1,738,514	MWh	5.37¢	93,272	6.19¢	107,658
24	IRM	4,219,890	kW	\$0.2454	1,036	\$0.2454	1,036
25	Nuclear Decomm.	1,738,514	MWh	\$0.000882	1,533	\$0.000882	1,533
26	Energy Waste Reduction	7,791	Meters	\$140.21	13,109	\$140.21	13,109
27	LIEAF	7,791	Meters	\$0.88	82	\$0.88	82
28	Distribution Surcharges	1,738,514	MWh	0.91¢	15,760	0.91¢	15,760
29							
30	Total Full Service Distribution	1,738,514	MWh	6.27¢	109,031	7.10¢	123,418
31	Total Full Service D4	1,738,514	MWh	13.84¢	240,690	14.97¢	260,244
32							
33	Choice Distribution	<u>Quantity</u>	<u>Units</u>	<u>Rate</u>	<u>Revenue (\$000)</u>	<u>Rate</u>	<u>Revenue (\$000)</u>
34							
35	Capacity						
36	Demand Charge	0	kW	\$3.57	0	\$9.18	0
37	Energy						
38	First 200 Hrs. Use	0	MWh	\$0.00000	0	\$0.00000	0
39	Excess	0	MWh	\$0.00000	0	\$0.00000	0
40							
41	Service Charge	773	Cust.	\$13.67	127	\$13.67	127
42							
43	Distribution Demand Charge	647,797	kW	\$21.80	14,122	\$25.21	16,330
44	Distribution Energy Charge	254,735	MWh	\$0.00000	0	\$0.00000	0
45	Distribution System	254,735	MWh	5.59¢	14,249	6.46¢	16,457
46	IRM	647,797	kW	\$0.2454	159	\$0.2454	159
47	Nuclear Decomm.	254,735	MWh	\$0.000882	225	\$0.000882	225
48	Energy Waste Reduction	773	Meters	\$140.21	1,301	\$140.21	1,301
49	LIEAF	773	Meters	\$0.88	8	\$0.88	8
50	Distribution Surcharges	254,735	MWh	0.66¢	1,692	0.66¢	1,692
51							
52	Total Choice D4	254,735	MWh	6.26¢	15,941	7.12¢	18,150
53							
54	Total D4	1,993,249	MWh	12.88¢	256,631	13.97¢	278,394
55	Increase/Decrease (\$)						21,763

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Water Heating Service Rate - Commercial D5

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 24 of 58

Line No.	(a) Description	(b) Billing Determinants	(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply					
1	Capacity					
2	Energy	9,881 MWh	\$0.00595	59	\$0.01534	152
3						
4	Non-capacity energy	9,881 MWh	\$0.04178	413	\$0.03457	342
5						
6	PSCR	9,881 MWh	\$0.00000	0	\$0.00000	0
7	REPS	764 Meters	\$0.00	0	\$0.00	0
8	Total Full Service Power Supply	9,881 MWh	4.77¢	472	4.99¢	493
9						
10	Full Service Distribution	Quantity Units				
11						
12	Service Charge	764 Cust.	\$1.95	18	\$1.95	18
13						
14	Distribution Charge	9,881 MWh	\$0.05288	523	\$0.06156	608
15	Distribution System	9,881 MWh	5.47¢	540	6.34¢	626
16	IRM	9,881 MWh	\$0.000595	6	\$0.000595	6
17	Nuclear Decomm.	9,881 MWh	\$0.000882	9	\$0.000882	9
18	Energy Waste Reduction	764 Meters	\$5.50	50	\$5.50	50
19	LIEAF	764 Meters	\$0.88	8	\$0.88	8
20	Distribution Surcharges	9,881 MWh	0.74¢	73	0.74¢	73
21						
22	Total Full Service Distribution	9,881 MWh	6.21¢	613	7.08¢	699
23	Total Full Service D5	9,881 MWh	10.98¢	1,085	12.07¢	1,192
24						
25	Choice Distribution	Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
26						
27	Capacity					
28	Energy	0 MWh	\$0.00595	0	\$0.01534	0
29						
30	Service Charge	1 Cust.	\$1.95	0	\$1.95	0
31						
32	Distribution Charge	4 MWh	\$0.05288	0	\$0.06156	0
33	Distribution System	4 MWh	5.81¢	0	6.68¢	0
34	IRM	4 MWh	\$0.000595	0	\$0.000595	0
35	Nuclear Decomm.	4 MWh	\$0.000882	0	\$0.000882	0
36	Energy Waste Reduction	1 Meters	\$5.50	0	\$5.50	0
37	LIEAF	1 Meters	\$0.88	0	\$0.88	0
38	Distribution Surcharges	4 MWh	1.87¢	0	1.87¢	0
39						
40	Total Choice D5	4 MWh	7.69¢	0	8.55¢	0
41						
42	Total D5	9,886 MWh	10.98¢	1,085	12.07¢	1,193
43	Increase/Decrease (\$)					107

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Energy Only Street Lighting E1.1

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 25 of 58

Line No.	(a) Description	(b) Billing Determinants Quantity Units	(c) Present Rate	(d) Revenue (\$000)	(e) Proposed Rate	(f) Revenue (\$000)
	Full Service Power Supply					
1	Capacity					
2	Energy					
3	Secondary	10,251 MWh	\$0.00692	71	\$0.01792	184
4	Dusk to Midnight	4 MWh	\$0.03023	0	\$0.07829	0
5	Primary Energy	0 MWh	\$0.00692	0	\$0.01792	0
6						
7	Non-capacity charge	10,256	\$0.04892	502	\$0.04045	415
8	Power Supply Subtotal	10,256 MWh	5.58¢	573	5.84¢	599
9						
10	PSCR	10,256 MWh	\$0.00000	0	\$0.00000	0
11	REPS	279 Meters	\$0.00	0	\$0.00	0
12	Total Full Service Power Supply	10,256 MWh	5.58¢	573	5.84¢	599
13						
14	Full Service Distribution					
15						
16	Distribution Charge	10,256 MWh	\$0.05288	542	\$0.06156	631
17	Distribution System	10,256 MWh	5.29¢	542	6.16¢	631
18	IRM	10,256 MWh	\$0.000595	6	\$0.000595	6
19	Nuclear Decomm.	10,256 MWh	\$0.000882	9	\$0.000882	9
20	Energy Waste Reduction	279 Meters	\$5.50	18	\$5.50	18
21	LIEAF	279 Meters	\$0.88	3	\$0.88	3
22	Distribution Surcharges	10,256 MWh	0.36¢	36	0.36¢	36
23						
24	Total Distribution	10,256 MWh	5.64¢	579	6.51¢	668
25	Total Full Service E1.1	10,256 MWh	11.23¢	1,152	12.35¢	1,267
26						
27	Choice Distribution	Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
28						
29	Capacity					
30	Energy					
31	Secondary	0 MWh	\$0.00692	0	\$0.01792	0
32	Dusk to Midnight	0 MWh	\$0.03023	0	\$0.07829	0
33	Primary Energy	0 MWh	\$0.00692	0	\$0.01792	0
34						
35	Distribution Charge	0 MWh	\$0.05288	0	\$0.06156	0
36	Distribution System	0 MWh		0		0
37	IRM	0 MWh	\$0.000595	0	\$0.000595	0
38	Nuclear Decomm.	0 MWh	\$0.000882	0	\$0.000882	0
39	Energy Waste Reduction	0 Meters	\$5.50	0	\$5.50	0
40	LIEAF	0 Meters	\$0.88	0	\$0.88	0
41	Distribution Surcharges	0 MWh		0		0
42						
43	Total Choice E1.1	0 MWh		0		0
44						
45	Total E1.1	10,256 MWh	11.23¢	1,152	12.35¢	1,267
46	Increase/Decrease (\$)					115

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Greenhouse Lighting Service Rate - Standard Contract Rider No. R7

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 26 of 58

Line No.	(a) Description	(b) Billing Determinants	(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply					
1	Capacity					
2	Energy	4,153 MWh	\$0.00577	24	\$0.01488	62
3						
4	Non-capacity					
5	Energy	4,153 MWh	\$0.04054	168	\$0.03354	139
6						
7	PSCR	4,153 MWh	\$0.00000	0	\$0.00000	0
8	REPS	9 Meters	\$0.00	0	\$0.00	0
9	Total Full Service Power Supply	4,153 MWh	4.63¢	192	4.84¢	201
10						
11	Full Service Distribution	Quantity Units				
12						
13	Service Charge	9 Cust.	\$1.95	0	\$1.95	0
14						
15	Distribution Charge	4,153 MWh	\$0.05288	220	\$0.06156	256
16	Distribution System	4,153 MWh	5.29¢	220	6.16¢	256
17	IRM	4,153 MWh	\$0.000595	2	\$0.000595	2
18	Nuclear Decomm.	4,153 MWh	\$0.000882	4	\$0.000882	4
19	Energy Waste Reduction	9 Meters	\$5.50	1	\$5.50	1
20	LIEAF	9 Meters	\$0.88	0	\$0.88	0
21	Distribution Surcharges	4,153 MWh	0.16¢	7	0.16¢	7
22						
23	Total Distribution	4,153 MWh	5.46¢	227	6.33¢	263
24	Total Full Service R7	4,153 MWh	10.09¢	419	11.17¢	464
25						
26	Choice Distribution	Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
27						
28	Capacity					
29	Energy	0 MWh	\$0.00577	0	\$0.01488	0
30						
31	Service Charge	0 Cust.	\$1.95	0	\$1.95	0
32						
33	Distribution Charge	0 MWh	\$0.05288	0	\$0.06156	0
34	Distribution System	0 MWh	0	0	0	0
35	IRM	0 MWh	\$0.000595	0	\$0.000595	0
36	Nuclear Decomm.	0 MWh	\$0.000882	0	\$0.000882	0
37	Energy Waste Reduction	0 Meters	\$5.50	0	\$5.50	0
38	LIEAF	0 Meters	\$0.88	0	\$0.88	0
39	Distribution Surcharges	0 MWh	0	0	0	0
40						
41	Total Choice R7	0 MWh	0	0	0	0
42						
43	Total R7	4,153 MWh	10.09¢	419	11.17¢	464
44	Increase/Decrease (\$)					45

Michigan Public Service Commission

DTE Electric Company

Present and Proposed Revenue

Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 27 of 58

(a)	(b)	(c)	(d)	(e)	(f)		
Description		Billing Determinants		Present		Proposed	
Full Service Power Supply	Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)	
Capacity							
Energy							
Summer June-Oct							
R8 All KWH- Separate Meter	18,111	MWh	\$0.01539	279	\$0.04013	727	
R8a initial Block of D3	1,429	MWh	\$0.01010	14	\$0.02605	37	
R8a Excess	444	MWh	\$0.01539	7	\$0.04013	18	
Winter Nov-May							
R8 First 1000 KWH- Sep Mtr	5,018	MWh	\$0.01539	77	\$0.04013	201	
R8 Excess	33,771	MWh	\$0.00510	172	\$0.01330	449	
R8a initial Block of D3	2,614	MWh	\$0.01010	26	\$0.02605	68	
Excess	11,955	MWh	\$0.00510	61	\$0.01330	159	
Non-capacity Charge	73,342	MWh	\$0.06173	4,527	\$0.05099	3,740	
Power Supply Subtotal	73,342	MWh	5,164		5,399		
PSCR	73,342	MWh	\$0.00000	0	\$0.00000	0	
REPS	1,678	Meters	\$0.00	0	\$0.00	0	
Total Full Service Power Supply	73,342	MWh	7.04¢	5,164	7.36¢	5,399	
Full Service Distribution	Quantity	Units					
Service Charge							
R8 Separate Meter	1,066	Cust.	\$11.25	144	\$11.25	144	
R8a	612	Cust.	\$11.25	83	\$11.25	83	
Distribution Charge	73,342	MWh	\$0.05288	3,878	\$0.06156	4,515	
Distribution System	73,342	MWh	5.60¢	4,105	6.47¢	4,742	
IRM	73,342	MWh	\$0.000595	44	\$0.000595	44	
Nuclear Decomm.	73,342	MWh	\$0.000882	65	\$0.000882	65	
Energy Waste Reduction	1,066	Meters	\$5.50	\$70	\$5.50	70	
LIEAF	1,066	Meters	\$0.88	11	\$0.88	11	
Distribution Surcharges	73,342	MWh	0.26¢	190	0.26¢	190	
Total Distribution	73,342	MWh	5.86¢	4,295	6.72¢	4,932	
Total Full Service R8	73,342	MWh	12.90¢	9,459	14.09¢	10,331	
Choice Distribution	Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)	
Capacity							
Energy							
R8 All KWH- Separate Meter	0	MWh	\$0.01539	0	\$0.04013	0	
R8a initial Block of D3	0	MWh	\$0.01010	0	\$0.02605	0	
R8a Excess	0	MWh	\$0.01539	0	\$0.04013	0	
Winter Nov-May							
R8 First 1000 KWH- Sep Mtr	0	MWh	\$0.01539	0	\$0.04013	0	
R8 Excess	0	MWh	\$0.00510	0	\$0.01330	0	
R8a initial Block of D3	0	MWh	\$0.01010	0	\$0.02605	0	
Excess	0	MWh	\$0.00510	0	\$0.01330	0	
Service Charge							
R8 Separate Meter	14	Cust.	\$11.25	2	\$11.25	2	
R8a	0	Cust.	\$11.25	0	\$11.25	0	
Distribution Charge	1,371	MWh	\$0.05288	73	\$0.06156	84	
Distribution System	1,371	MWh	5.43¢	74	6.29¢	86	
IRM	1,371	MWh	\$0.000595	1	\$0.000595	1	
Nuclear Decomm.	1,371	MWh	\$0.000882	1	\$0.000882	1	
Energy Waste Reduction	14	Meters	\$5.50	1	\$5.50	1	
LIEAF	14	Meters	\$0.88	0	\$0.88	0	
Distribution Surcharges	1,371	MWh	0.23¢	3	0.23¢	3	
Total Choice R8	1,371	MWh	5.65¢	78	6.52¢	89	
Total R8	74,713	MWh	12.76¢	9,537	13.95¢	10,420	
Increase/Decrease (\$)				884			

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Primary Supply Rate - D11
All Voltages

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 28 of 58

Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply						
	Capacity						
1	Power Supply Demand	21,460,521	kW	3.56	76,399	9.19	197,118
2	<u>Voltage Level Discount</u>						
3	Subtransmission	2,259,951	kW	(0.07)	(158)	(0.19)	(422)
4	Transmission	6,643,543	kW	(0.15)	(997)	(0.39)	(2,573)
5							
6	<u>Energy</u>						
7	On-Peak	2,894,545	MWh		0		0
8	Off-Peak	8,610,839	MWh		0		0
9	Total Energy	11,505,383	MWh				
10							
11	<u>Voltage Level Discount</u>						
12	Subtransmission	1,298,106	MWh	0.00000	0	0.00000	0
13	Transmission	4,354,860	MWh	0.00000	0	0.00000	0
14	Total Capacity	11,505,383	MWh		75,245		194,124
15							
16	Non-Capacity						
17	Power Supply Demand	21,460,521	kW	13.33	286,069	8.35	179,159
18	<u>Voltage Level Adjustment</u>						
19	Subtransmission	2,259,951	kW	(0.24)	(542)	(0.17)	(383)
20	Transmission	6,643,543	kW	(0.53)	(3,521)	(0.35)	(2,338)
21	<u>Energy</u>						
22	On-Peak	2,894,545	MWh	0.04257	123,221	0.04388	127,015
23	Off-Peak	8,610,839	MWh	0.03257	280,455	0.03388	291,744
24	<u>Voltage Level Discount</u>						
25	Subtransmission	1,298,106	MWh	(0.00062)	(805)	(0.00064)	(836)
26	Transmission	4,354,860	MWh	(0.00138)	(6,010)	(0.00143)	(6,245)
27	Power Supply Subtotal	11,505,383	MWh		754,111		782,238
28							
29	PSCR	11,505,383	MWh	0.00000	0	0.00000	0
30	REPS	2,079	Cust.	0.0	0	0.0	0
31	Total Full Service Power Supply	11,505,383	MWh	6.55¢	754,111	6.80¢	782,238
32							
33	Full Service Distribution	Quantity	Units				
34							
35	Service Charge - PV	1,949	Cust.	70	1,637	70	1,637
36	Service Charge - SV	70	Cust.	375	315	375	315
37	Service Charge - TV	60	Cust.	375	270	375	270
38	<u>Distribution Charges</u>						
39	Primary	15,679,728	kW	6.15	96,430	6.66	104,460
40		5,852,418	MWh				
41	Subtransmission	3,118,737	kW	1.96	6,113	1.82	5,677
42		1,298,106	MWh				
43	Transmission	8,008,087	kW	0.86	6,887	0.99	7,938
44		4,354,860	MWh				
45	<u>Substation Credit</u>						
46	Demand	3,035,972	kW	(0.30)	(911)	(0.30)	(911)
47	Energy	181,296	MWh	(0.0004)	(73)	(0.0004)	(73)
48	Distribution System	11,505,383	MWh	0.96¢	110,668	1.04¢	119,313
49							
50	IRM - PV	15,679,728	kW	0.0727	1,140	0.0727	1,140
51	IRM - SV	3,118,737	kW	0.0312	97	0.0312	97
52	IRM - TV	8,008,087	kW	0.0000	0	0.0000	0
53	Nuclear Decommissioning	11,505,383	MWh	0.000882	10,148	0.000882	10,148
54	Energy Waste Reduction	2,463	Meters	1,237.99	36,597	1,237.99	36,597
55	LIEAF	2,463	Meters	0.88	26	0.88	26
56	Distribution Surcharges	11,505,383	MWh	0.42¢	48,008	0.42¢	48,008
57							
58	Total Full Service Distribution	11,505,383	MWh	1.38¢	158,676	1.45¢	167,321
59	Total Full Service D11	11,505,383	MWh	7.93¢	912,788	8.25¢	949,560

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Primary Supply Rate - D11 (Cont'd)
All Voltages

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 29 of 58

Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
60	Choice Distribution						
61	Capacity						
62	Power Supply Demand	0	kW	3.56	0	9.19	0
63	<u>Voltage Level Discount</u>						
64	Subtransmission	0	kW	(0.07)	0	(0.19)	0
65	Transmission	0	kW	(0.15)	0	(0.39)	0
66							
67	<u>Energy</u>						
68	On-Peak	0	MWh	0.00000	0	0.00000	0
69	Off-Peak	0	MWh	0.00000	0	0.00000	0
70	Total Energy	0	MWh				
71							
72	<u>Voltage Level Discount</u>						
73	Subtransmission	0	MWh	0.00000	0	0.00000	0
74	Transmission	0	MWh	0.00000	0	0.00000	0
75	Total Capacity	0	MWh		0		0
76							
77	Service Charge - PV	530	Cust.	70	445	70	445
78	Service Charge - SV	11	Cust.	375	50	375	50
79	Service Charge - TV	8	Cust.	375	34	375	34
80	<u>Distribution Charges</u>						
81	Primary	5,033,729	kW	6.15	30,957	6.66	33,535
82		2,011,974	MWh				
83	Subtransmission	558,645	kW	1.96	1,095	1.82	1,017
84		204,630	MWh				
85	Transmission	2,289,408	kW	0.86	1,969	0.99	2,269
86		831,189	MWh				
87	Substation Credit						
88	Demand	1,797,568	kW	(0.30)	(539)	(0.30)	(539)
89	Energy	41,020	MWh	(0.0004)	(16)	(0.0004)	(16)
90	Distribution System	3,047,793	MWh	1.12¢	33,995	1.21¢	36,795
91							
92	IRM - PV	5,033,729	kW	0.0727	366	0.0727	366
93	IRM - SV	558,645	kW	0.0312	17	0.0312	17
94	IRM - TV	2,289,408	kW	0	0	0	0
95	Nuclear Decommissioning	3,047,793	MWh	0.000882	2,688	0.000882	2,688
96	Energy Waste Reduction	631	Meters	1,237.99	9,367	1,237.99	9,367
97	LIEAF	631	Meters	0.88	7	0.88	7
98	Distribution Surcharges	3,047,793	MWh	0.41¢	12,446	0.41¢	12,446
99							
100	Total Choice D11	3,047,793	MWh	1.52¢	46,440	1.62¢	49,241
101							
102	Total D11	14,553,177	MWh	6.59¢	959,228	6.86¢	998,800
103	Increase/Decrease (\$)						39,572

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Primary Educational Institute - D6.2
All Voltages

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 30 of 58

Line No.	(a) Description	(b) Billing Determinants	(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply					
	Capacity					
1	Power Supply Demand	1,641,257 kW	3.58	5,876	10.79	17,701
2						
3	<u>Voltage Level Adjustment</u>					
4	Subtransmission	783,019 kW	(0.07)	(55)	(0.22)	(172)
5	Transmission	0 kW	(0.15)	0	(0.45)	0
6						
7	<u>Energy</u>					
8	On-Peak	195,100 MWh	0.00000	0	0.00000	0
9	Off-Peak	503,918 MWh	0.00000	0	0.00000	0
10	Total Energy	699,018 MWh				
11						
12	<u>Voltage Level Discount</u>					
13	Subtransmission	326,833 MWh	0.00000	0	0.00000	0
14	Transmission	0 MWh	0.00000	0	0.00000	0
15	Total Capacity	699,018 MWh		5,821		17,530
16						
17	Non-Capacity					
18	Power Supply Demand	1,641,257 kW	10.04	16,478	4.56	7,479
19	<u>Voltage Level Adjustment</u>					
20	Subtransmission	783,019 kW	(0.18)	(141)	(0.09)	(73)
21	Transmission	0 kW	(0.40)	0	(0.19)	0
22						
23						
24	<u>Energy</u>					
25	On-Peak	195,100 MWh	0.04322	8,432	0.04837	9,436
26	Off-Peak	503,918 MWh	0.04022	20,268	0.04537	22,861
27	<u>Voltage Level Discount</u>					
28	Subtransmission	326,833 MWh	(0.00073)	(239)	(0.00082)	(267)
29	Transmission	0 MWh	(0.00162)	0	(0.00182)	0
30	Power Supply Subtotal	699,018 MWh		50,619		56,966
31						
32	PSCR	699,018 MWh	0.00000	0	0.00000	0
33	REPS	123 Cust.	0.0	0	0.0	0
34	Total Full Service Power Supply	699,018 MWh	7.24¢	50,619	8.15¢	56,966
35						
36	Full Service Distribution	Quantity Units				
37						
38	Service Charge - PV	117 Cust.	70	98	70	98
39	Service Charge - SV	6 Cust.	375	27	375	27
40	Service Charge - TV	0 Cust.	375	0	375	0
41	<u>Distribution Charges</u>					
42	Primary	1,127,347 kW	6.15	6,933	6.66	7,510
43		372,184 MWh				
44	Subtransmission	999,979 kW	1.96	1,960	1.82	1,820
45		326,833 MWh				
46	Transmission	0 kW	0.86	0	0.99	0
47		0 MWh				
48	<u>Substation Credit</u>					
49	Demand	13,544 kW	(0.30)	(4)	(0.30)	(4)
50	Energy	0 MWh	(0.0004)	(0)	(0.0004)	(0)
51	Distribution System	699,018 MWh	1.29¢	9,014	1.35¢	9,452
52						
53	IRM - PV	1,127,347 kW	0.0727	82	0.0727	82
54	IRM - SV	999,979 kW	0.0312	31	0.0312	31
52	IRM - TV	0 kW	0	0	0	0
53	Nuclear Decommissioning	699,018 MWh	0.000882	617	0.000882	617
54	Energy Waste Reduction	146 Meters	1,237.99	2,169	1,237.99	2,169
55	LIEAF	146 Meters	0.88	2	0.88	2
56	Distribution Surcharges	699,018 MWh	0.41¢	2,900	0.41¢	2,900
57						
58	Total Full Service Distribution	699,018 MWh	1.70¢	11,915	1.77¢	12,352
59	Total Full Service D6.2	699,018 MWh	8.95¢	62,534	9.92¢	69,319

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Primary Educational Institute - D6.2 (Cont'd)
All Voltages

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 31 of 58

Line No.	(a) Description	(b) Billing Determinants	(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
60	Choice Distribution					
61	Capacity					
62	Power Supply Demand	kW	3.58	0	10.79	0
63						
64	Energy					
65	On-Peak	MWh	0.00000	0	0.00000	0
66	Off-Peak	MWh	0.00000	0	0.00000	0
67	Total Energy	MWh				
68						
69	Voltage Level Adjustment					
70	Subtransmission	kW	(0.07)	0	(0.22)	0
71	Transmission	kW	(0.15)	0	(0.45)	0
72	Total Capacity					0
73						
74	Service Charge - PV	153 Cust.	70	129	70	129
75	Service Charge - SV	0 Cust.	375	0	375	0
76	Service Charge - TV	0 Cust.	375	0	375	0
77	Distribution Charges					
78	Primary	1,528,071 kW	6.15	9,398	6.66	10,180
79		394,774 MWh				
80	Subtransmission	0 kW	1.96	0	1.82	0
81		0 MWh				
82	Transmission	0 kW	0.86	0	0.99	0
83		0 MWh				
84	Substation Credit					
85	Demand	0 kW	(0.30)	0	(0.30)	0
86	Energy	0 MWh	(0.0004)	0	(0.0004)	0
87	Distribution System	394,774 MWh	2.41¢	9,526	2.61¢	10,309
88						
89	IRM - PV	1,528,071 kW	0.0727	111	0.0727	111
90	IRM - SV	0 kW	0.0312	0	0.0312	0
91	IRM - TV	0 kW	0	0	0	0
92	Nuclear Decommissioning	394,774 MWh	0.000882	348	0.000882	348
93	Energy Waste Reduction	156 Meters	1,237.99	2,314	1,237.99	2,314
94	LIEAF	156 Meters	0.88	2	0.88	2
95	Distribution Surcharges	394,774 MWh	0.70¢	2,775	0.70¢	2,775
96						
97	Total Choice D6.2	394,774 MWh	3.12¢	12,301	3.31¢	13,083
98						
99	Total D6.2	1,093,792 MWh	6.84¢	74,835	7.53¢	82,402
100	Increase/Decrease (\$)					7,567

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Interruptible Supply Rate - D8
All Voltages

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 32 of 58

Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply						
	Capacity						
1	Power Supply Demand	941,965	kW	1.62	1,526	4.24	3,993
2	<u>Voltage Level Adjustment</u>						
3	Subtransmission	112,036	kW	(0.03)	(3)	(0.09)	(10)
4	Transmission	153,588	kW	(0.07)	(11)	(0.18)	(27)
5							
6	Product Protection Demand	135,807	kW	3.56	483	9.19	1,247
7	<u>Voltage Level Adjustment</u>						
8	Subtransmission	8,292	kW	(0.07)	(1)	(0.19)	(2)
9	Transmission	65,050	kW	(0.15)	(10)	(0.39)	(25)
10							
11	<u>Energy</u>						
12	On-Peak	135,663	MWh	0.00000	0	0.00000	0
13	Off-Peak	374,067	MWh	0.00000	0	0.00000	0
14	Total Energy	509,730	MWh				
15							
16	<u>Voltage Level Discount</u>						
17	Subtransmission	62,933	MWh	0.00000	0	0.00000	0
18	Transmission	125,103	MWh	0.00000	0	0.00000	0
19	Total Capacity	509,730	MWh		1,985		5,176
20							
21	Non-Capacity						
22	Power Supply Demand	941,965	kW	8.50	8,007	6.00	5,650
23	<u>Voltage Level Adjustment</u>						
24	Subtransmission	112,036	kW	(0.15)	(17)	(0.12)	(14)
25	Transmission	153,588	kW	(0.33)	(51)	(0.25)	(39)
26							
27	Product Protection Demand	135,807	kW	13.33	1,810	8.35	1,134
28	<u>Voltage Level Discount</u>						
29	Subtransmission	8,292	kW	(0.24)	(2)	(0.17)	(1)
30	Transmission	65,050	kW	(0.53)	(34)	(0.35)	(23)
31							
32	<u>Energy</u>						
33	On-Peak	135,663	MWh	0.04257	5,775	0.04388	5,953
34	Off-Peak	374,067	MWh	0.03257	12,183	0.03388	12,674
35	<u>Voltage Level Discount</u>						
36	Subtransmission	62,933	MWh	(0.00062)	(39)	(0.00064)	(41)
37	Transmission	125,103	MWh	(0.00138)	(173)	(0.00143)	(179)
38	Power Supply Subtotal	509,730	MWh		29,445		30,290
39							
40	PSCR	509,730	MWh	0.00000	0	0.00000	0
41	REPS	125	Cust.	0.00	0	0.00	0
42	Total Full Service Power Supply	509,730	MWh	5.78¢	29,445	5.94¢	30,290
43							
44	Full Service Distribution	Quantity	Units				
45							
46	Service Charge - PV	119	Cust.	70	100	70	100
47	Service Charge - SV	4	Cust.	375	18	375	18
48	Service Charge - TV	2	Cust.	375	9	375	9
49	<u>Distribution Charges</u>						
50	Primary	880,229	kW	6.15	5,413	6.66	5,864
51		321,694	MWh				
52	Subtransmission	129,679	kW	1.96	254	1.82	236
53		62,933	MWh				
54	Transmission	277,821	kW	0.86	239	0.99	275
55		125,103	MWh				
56	<u>Substation Credit</u>						
57	Demand	268,469	kW	(0.30)	(81)	(0.30)	(81)
58	Energy	0	MWh	(0.0004)	0	(0.0004)	0
59	Distribution System	509,730	MWh	1.17¢	5,953	1.26¢	6,422
60							
61	IRM - PV	880,229	kW	0.0727	64	0.0727	64
62	IRM - SV	129,679	kW	0.0312	4	0.0312	4
63	IRM - TV	277,821	kW	0	0	0	0
64	Nuclear Decommissioning	509,730	MWh	0.000882	450	0.000882	450
65	Energy Waste Reduction	133	Meters	1,237.99	1,979	1,237.99	1,979
66	LIEAF	133	Meters	0.88	1	0.88	1
67	Distribution Surcharges	509,730		0.49¢	2,498	0.49¢	2,498
68							
69	Total Full Service Distribution	509,730	MWh	1.66¢	8,451	1.75¢	8,920
70	Total Full Service D8	509,730	MWh	7.43¢	37,896	7.69¢	39,210

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Interruptible Supply Rate - D8 (Cont'd)
All Voltages

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 33 of 58

Line No.	(a) Description	(b) Billing Determinants		(c) Present Rate	(d) Revenue (\$000)	(e) Proposed Rate	(f) Revenue (\$000)
71	Choice Distribution	Quantity	Units				
72	Capacity						
73	Power Supply Demand	0	kW	1.62	0	4.24	0
74	<u>Voltage Level Discount</u>						
75	Subtransmission	0	kW	(0.03)	0	(0.09)	0
76	Transmission	0	kW	(0.07)	0	(0.18)	0
77							
78	Product Protection Demand	0	kW	3.56	0	9.19	0
79	<u>Voltage Level Discount</u>						
80	Subtransmission	0	kW	(0.07)	0	(0.19)	0
81	Transmission	0	kW	(0.15)	0	(0.39)	0
82							
83	<u>Energy</u>						
84	On-Peak	0	MWh	0.00000	0	0.00000	0
85	Off-Peak	0	MWh	0.00000	0	0.00000	0
86	Total Energy	0	MWh				
87							
88	<u>Voltage Level Discount</u>						
89	Subtransmission	0	MWh	0.00000	0	0.00000	0
90	Transmission	0	MWh	0.00000	0	0.00000	0
91	Total Capacity	0	MWh				0
92							
93	Service Charge - PV	10	Cust.	70	8	70	8
94	Service Charge - SV	2	Cust.	375	9	375	9
95	Service Charge - TV	0	Cust.	375	0	375	0
96	<u>Distribution Charges</u>						
97	Primary	226,275	kW	6.15	1,392	6.66	1,507
98		110,144	MWh				
99	Subtransmission	66,324	kW	1.96	130	1.82	121
100		23,118	MWh				
101	Transmission	0	kW	0.86	0	0.99	0
102		0	MWh				
103	<u>Substation Credit</u>						
104	Demand	0	kW	(0.30)	0	(0.30)	0
105	Energy	0	MWh	(0.0004)	0	(0.0004)	0
106	Distribution System	133,261	MWh	1.15¢	1,539	1.23¢	1,646
107							
108	IRM - PV	226,275	kW	0.072700	16	0.072700	16
109	IRM - SV	66,324	kW	0.031200	2	0.031200	2
110	IRM - TV	0	kW	0.000000	0	0.000000	0
111	Nuclear Decommissioning	133,261	MWh	0.000882	118	0.000882	118
112	Energy Waste Reduction	16	Meters	1,237.99	233	1,237.99	233
113	LIEAF	16	Meters	0.88	0	0.88	0
114	Distribution Surcharges	133,261	MWh	0.28¢	370	0.28¢	370
115							
116	Total Choice D8	133,261	MWh	1.43¢	1,909	1.51¢	2,015
117							
118	Total D8	642,991	MWh	6.19¢	39,805	6.41¢	41,225
119	Increase/Decrease (\$)						1,421

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
All Electric School Building Rate - D10
Primary Voltage

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 34 of 58

Line No.	(a) Description	(b) Billing Determinants Quantity Units	(c) Present Rate	(d) Present Revenue (\$000)	(e) Proposed Rate	(f) Proposed Revenue (\$000)
	Full Service Power Supply					
	Capacity					
1	Energy					
2	Energy -- Winter	14,018 MWh	0.00094	13	0.01445	203
3	Energy -- Summer	6,872 MWh	0.02107	145	0.03458	238
4	Total Capacity	20,890 MWh		158		440
5						
6	Non-Capacity					
7	Energy	20,890 MWh	0.07430	1,552	0.06384	1,334
8	Power Supply Subtotal					
9						
10	PSCR	20,890 MWh	0.00000	0	0.00000	0
11	REPS	19 Cust.	0.00	0	0.00	0
12	Total Full Service Power Supply	20,890 MWh	8.19¢	1,710	8.49¢	1,774
13						
14	Full Service Distribution					
15						
16	Service Charge	19 Cust.	70	16	70	16
17						
18	<u>Distribution Charges</u>					
19	Primary	20,890 MWh	0.01968	411	0.01973	412
20	Distribution System	20,890 MWh	2.04¢	427	2.05¢	428
21						
22	IRM	20,890 MWh	0.000233	5	0.000233	5
23	Nuclear Decommissioning	20,890 MWh	0.000882	18	0.000882	18
24	Energy Waste Reduction	19 Meters	1,237.99	283	1,237.99	283
25	LIEAF	19 Meters	0.88	0	0.88	0
26	Distribution Surcharges	20,890 MWh	1.47¢	307	1.47¢	307
27						
28	Total Full Service Distribution	20,890 MWh	3.51¢	734	3.52¢	735
29	Total Full Service D10	20,890 MWh	11.70¢	2,444	12.01¢	2,509
30						
31	Choice Distribution					
32	Capacity					
33	Energy					
34	Energy -- Winter	0 MWh	0.00094	0	0.01445	0
35	Energy -- Summer	0 MWh	0.02107	0	0.03458	0
36	Total Capacity	0 MWh				0
37						
38	Service Charge	12 Cust.	70	10	70	10
39						
40	<u>Distribution Charges</u>					
41	Primary	13,396 MWh	0.01968	264	0.01973	264
42	Distribution System	13,396 MWh	2.04¢	274	2.05¢	274
43						
44	IRM	13,396 MWh	0.000233	3	0.000233	3
45	Nuclear Decommissioning	13,396 MWh	0.000882	12	0.000882	12
46	Energy Waste Reduction	12 Meters	1,237.99	178	1,237.99	178
47	LIEAF	12 Meters	0.88	0	0.88	0
48	Distribution Surcharges	13,396 MWh	1.44¢	193	1.44¢	193
49						
50	Total Choice D10	13,396 MWh	3.49¢	467	3.49¢	468
51						
52	Total D10	34,286 MWh	8.49¢	2,911	8.68¢	2,977
53	Increase/Decrease (\$)					65

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
EXPERIMENTAL LARGE CUSTOMER LOW
PEAK DEMAND SUPPLY RATE - D12
All Voltages

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 35 of 58

Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d)	(e) Proposed	(f)
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply						
	Capacity						
1	Power Supply Demand (October through May)	0	kW	0.32	0	0.33	0
2	Power Supply Demand (June through September)	0	kW	8.00	0	8.30	0
3							
4	<u>Voltage Level Discount - Transmission</u>						
5	CVLD (October through May)	0	kW	(0.005)	0	(0.005)	0
6	CVLD (June through September)	0	kW	(0.14)	0	(0.15)	0
7							
8	Total Capacity				0		0
9							
10	Non-Capacity						
11	Power Supply Demand (October through May)	0	kW	0.32	0	0.33	0
12	Power Supply Demand (June through September)	0	kW	41.16	0	42.70	0
13							
14	<u>Voltage Level Discount - Transmission</u>						
15	NCVLD (October through May)	0	kW	(0.005)	0	(0.005)	0
16	NCVLD (June through September)	0	kW	(0.70)	0	(0.73)	0
17							
18	<u>Energy</u>						
19	On-Peak	0	MWh	0.04112	0	0.04265	0
20	Off-Peak	0	MWh	0.03611	0	0.03746	0
21							
22	<u>Voltage Level Discount - Transmission</u>	0	MWh	(0.00056)	0	(0.00058)	0
23							
24	Power Supply Subtotal	0	MWh		0		0
25							
26	PSCR	0	MWh	0.00000	0	0.00000	0
27	REPS	0	Cust.	0.0	0	0.0	0
28	Total Full Service Power Supply	0	MWh	#DIV/0!	0	#DIV/0!	0
29							
30	Full Service Distribution	Quantity	Units				
31							
32	Service Charge - SV	0	Cust.	375	0	375	0
33	Service Charge - TV	0	Cust.	375	0	375	0
34	<u>Distribution Charges</u>						
35	Subtransmission	0	kW	1.96	0	1.82	0
36		0	MWh				
37	Transmission	0	kW	0.86	0	0.99	0
38		0	MWh				
39	<u>Substation Credit</u>						
40	Demand	0	kW	(0.30)	0	(0.30)	0
41	Energy	0	MWh	(0.0004)	0	(0.0004)	0
42	Distribution System	0	MWh	#DIV/0!	0	#DIV/0!	0
43							
44	IRM - SV	0	kW	0.031200	0	0.031200	0
45	IRM - TV	0	kW	0.000000	0	0.000000	0
46	Nuclear Decommissioning	0	MWh	0.000882	0	0.000882	0
47	Energy Waste Reduction	0	Meters	1,237.99	0	1,237.99	0
48	LIEAF	0	Meters	0.88	0	0.88	0
49	Distribution Surcharges	0	MWh	#DIV/0!	0	#DIV/0!	0
50							
51	Total Full Service Distribution	0	MWh	#DIV/0!	0	#DIV/0!	0
52	Total Full Service D12	0	MWh	#DIV/0!	0	#DIV/0!	0

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
XL High Load Factor Rate - D13
All Voltages

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 36 of 58

Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply						
1	Capacity	200,000	MWh	0.01514	3,028	0.01514	3,028
2	Non-Capacity	200,000	MWh	0.03430	6,860	0.03287	6,574
3	Transmission	200,000	MWh	0.00304	608	0.00308	616
4	Power Supply Subtotal	200,000	MWh		10,496		10,218
5							
6	REPS	3	Cust.	0.00	0	0.00	0
7	Total Full Service Power Supply	200,000	MWh	5.25¢	10,496	5.11¢	10,218
8							
9	Full Service Distribution	Quantity	Units				
10							
11	Service Charge - PV	1	Cust.	70	1	70	1
12	Service Charge - SV	0	Cust.	375	0	375	0
13	Service Charge - TV	2	Cust.	375	9	375	9
14							
15	Distribution Charges						
16	Primary	32,850	MWh	0.00936	307	0.01014	333
17	Sub-transmission	0	MWh	0.00298	0	0.00277	0
18	Transmission	167,150	MWh	0.00131	219	0.00151	252
19							
20	Administration Charge	200,000	MWh	0.00015	30	0.00015	30
21							
22	Substation Credit						
23	Primary Side		MWh	(0.00040)	0	(0.00040)	0
24	Customer Owned		MWh	(0.00055)	0	(0.00055)	0
25							
26	Distribution System	200,000	MWh	0.28¢	566	0.31¢	625
27							
28	IRM - PV	32,850	MWh	0.000133	4	0.000133	4
29	IRM - SV	0	MWh	0.000057	0	0.000057	0
30	IRM - TV	167,150	MWh	0.000000	0	0.000000	0
31	Energy Waste Reduction	3	Meters	1,237.99	45	1,237.99	45
32	LIEAF	3	Meters	0.88	0	0.88	0
33	Distribution Surcharges	200,000	MWh	0.02¢	49	0.02¢	49
34							
35	Total Full Service Distribution	200,000	MWh	0.31¢	615	0.34¢	674
36	Total Full Service D13	200,000	MWh	5.56¢	11,111	5.45¢	10,892
37	Increase/Decrease (\$)						(219)

Michigan Public Service Commission
DTE Electric Company
Optional TOU Primary Supply Rate - D14
Designed Revenue Neutral to D11
All Voltages

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 37 of 58

Line No.	(a) Description	(b) Billing Determinants		(c) (d) Proposed D11		(e) (f) Revenue Neutral Design	
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply						
	Capacity						
1	June - September						
2	On Peak (11am - 7pm M-F, excl holidays)	1,070,182	MWh			0.02649	28,345
3	Off Peak	3,054,881	MWh			0.01576	48,149
4	October - May						
5	On Peak (11am - 7pm M-F, excl holidays)	1,824,363	MWh			0.01831	33,400
6	Off Peak	5,555,958	MWh			0.01576	87,569
7	<u>Voltage Level Discount</u>						
8	Subtransmission	1,298,106	MWh			(0.00030)	(394)
9	Transmission	4,354,860	MWh			(0.00068)	(2,945)
10	Total Capacity	11,505,383	MWh				
11							
12	Non-Capacity						
13	June - September						
14	On Peak (11am - 7pm M-F, excl holidays)	1,070,182	MWh			0.08024	85,873
15	Off Peak	3,054,881	MWh			0.04775	145,871
16	October - May						
17	On Peak (11am - 7pm M-F, excl holidays)	1,824,363	MWh			0.05547	101,189
18	Off Peak	5,555,958	MWh			0.04775	265,298
19	<u>Voltage Level Discount</u>						
20	Subtransmission	1,298,106	MWh			(0.00092)	(1,195)
21	Transmission	4,354,860	MWh			(0.00205)	(8,922)
22	Power Supply Subtotal	11,505,383	MWh		0		782,238
23							
24	PSCR	11,505,383	MWh	0.00000	0	0.00000	0
25	REPS	2,079	Cust.	0.0	0	0.0	0
26	Total Full Service Power Supply	11,505,383	MWh	6.80¢	782,238	6.80¢	782,238
27							
28	Full Service Distribution	Quantity	Units				
29							
30	Service Charge - PV	1,949	Cust.	70	1,637	70	1,637
31	Service Charge - SV	70	Cust.	375	315	375	315
32	Service Charge - TV	60	Cust.	375	270	375	270
33	<u>Distribution Charges</u>						
34	Primary	15,679,728	kW	6.66	104,460	6.66	104,460
35		5,852,418	MWh				
36	Subtransmission	3,118,737	kW	1.82	5,677	1.82	5,677
37		1,298,106	MWh				
38	Transmission	8,008,087	kW	0.99	7,938	0.99	7,938
39		4,354,860	MWh				
40	<u>Substation Credit</u>						
41	Demand	3,035,972	kW	(0.30)	(911)	(0.30)	(911)
42	Energy	181,296	MWh	(0.0004)	(73)	(0.0004)	(73)
43	Distribution System	11,505,383	MWh	1.04¢	119,313	1.04¢	119,313
44							
45	IRM - PV	15,679,728	kW	0.0727	1,140	0.0727	1,140
46	IRM - SV	3,118,737	kW	0.0312	97	0.0312	97
47	IRM - TV	8,008,087	kW	0	0	0.0000	0
48	Nuclear Decommissioning	11,505,383	MWh	0.000882	10,148	0.000882	10,148
49	Energy Waste Reduction	2,463	Meters	1,237.99	36,597	1,237.99	36,597
50	LIEAF	2,463	Meters	0.88	26	0.88	26
51	Distribution Surcharges	11,505,383	MWh	0.42¢	48,008	0.42¢	48,008
52							
53	Total Full Service Distribution	11,505,383	MWh	1.45¢	167,321	1.45¢	167,321
54	Total Full Service D14	11,505,383	MWh	8.25¢	949,560	8.25¢	949,560

Michigan Public Service Commission
DTE Electric Company
Optional TOU Primary Supply Rate - D14 Cont'd
Designed Revenue Neutral to D11
All Voltages

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 38 of 58

Line No.	(a) Description	(b) Billing Determinants		(c) (d) Proposed D11		(e) (f) Revenue Neutral Design	
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
55	Choice Distribution						
56	Capacity						
57	June - September						
58	On Peak (11am - 7pm M-F, excl holidays)	0	MWh			0.02649	0
59	Off Peak	0	MWh			0.01576	0
60	October - May						0
61	On Peak (11am - 7pm M-F, excl holidays)	0	MWh			0.01831	0
62	Off Peak	0	MWh			0.01576	0
63	<u>Voltage Level Discount</u>						0
64	Subtransmission	0	MWh			(0.00030)	0
65	Transmission	0	MWh			(0.00068)	0
66	Total Capacity	0	MWh		0		0
67							
68	Service Charge - PV	530	Cust.	70	445	70	445
69	Service Charge - SV	11	Cust.	375	50	375	50
70	Service Charge - TV	8	Cust.	375	34	375	34
71	<u>Distribution Charges</u>						
72	Primary	5,033,729	kW	6.66	33,535	6.66	33,535
73		2,011,974	MWh				
74	Subtransmission	558,645	kW	1.82	1,017	1.82	1,017
75		204,630	MWh				
76	Transmission	2,289,408	kW	0.99	2,269	0.99	2,269
77		831,189	MWh				
78	Substation Credit						
79	Demand	1,797,568	kW	(0.30)	(539)	(0.30)	(539)
80	Energy	41,020	MWh	(0.0004)	(16)	(0.0004)	(16)
81	Distribution System	3,047,793	MWh	1.21¢	36,795	1.21¢	36,795
82							
83	IRM - PV	5,033,729	kW	0.0727	366	0.0727	366
84	IRM - SV	558,645	kW	0.0312	17	0.0312	17
85	IRM - TV	2,289,408	kW	0	0	0	0
86	Nuclear Decommissioning	3,047,793	MWh	0.000882	2,688	0.000882	2,688
87	Energy Waste Reduction	631	Meters	1,237.99	9,367	1,237.99	9,367
88	LIEAF	631	Meters	0.88	7	0.88	7
89	Distribution Surcharges	3,047,793	MWh	0.41¢	12,446	0.41¢	12,446
90							
91	Total Choice D14	3,047,793	MWh	1.62¢	49,241	1.62¢	49,241
92							
93	Total D14	14,553,177	MWh	6.86¢	998,800	6.86¢	998,800
94	Increase/Decrease (\$)						0

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Alternative Metal Melting Rider - R1.1

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 39 of 58

Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
	Full Service Power Supply						
	Capacity						
1	Energy						
2	Secondary						
3	First 100 Hours Use	2,315	MWh	0.00706	16	0.01789	41
4	Excess Hours Use	803	MWh	0.00267	2	0.00676	5
5	Primary						
6	First 100 Hours Use	6,627	MWh	0.00525	35	0.01330	88
7	Excess Hours Use	712	MWh	0.00191	1	0.00484	3
8	Subtransmission						
9	First 100 Hours Use	15,552	MWh	0.00512	80	0.01297	202
10	Excess Hours Use	35,693	MWh	0.00178	64	0.00451	161
11	Transmission						
12	First 100 Hours Use	37,938	MWh	0.00434	165	0.01100	417
13	Excess Hours Use	25,522	MWh	0.00144	37	0.00365	93
14	Total Capacity	125,163	MWh		399		1,011
15							
16	Non-Capacity						
17	Energy	125,163	MWh	0.05251	6,572	0.04892	6,123
18	Power Supply Subtotal				6,971		7,134
19							
20	PSCR	125,163	MWh	0.00000	0	0.00000	0
21	REPS	17	Cust.	0.00	0	0.00	0
22	Total Full Service Power Supply	125,163	MWh	5.57¢	6,971	5.70¢	7,134
23							
24	Full Service Distribution	Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
25							
26	Distribution Charges						
27	Secondary						
28	First 100 Hours Use	2,315	MWh	0.05288	122	0.06156	142
29	Excess Hours Use	803	MWh	0.05288	42	0.06156	49
30	Primary						
31	First 100 Hours Use	6,627	MWh	0.01832	121	0.02015	134
32	Excess Hours Use	712	MWh	0.01832	13	0.02015	14
33	Subtransmission						
34	First 100 Hours Use	15,552	MWh	0.00677	105	0.00532	83
35	Excess Hours Use	35,693	MWh	0.00677	242	0.00532	190
36	Transmission						
37	First 100 Hours Use	37,938	MWh	0.00274	104	0.00600	228
38	Excess Hours Use	25,522	MWh	0.00274	70	0.00600	153
39							
40	Substation Credit						
41	Energy	3,966	MWh	(0.00300)	(12)	(0.00300)	(12)
42	Distribution System	125,163	MWh	0.65¢	808	1.48¢	982
43							
44	IRM - DV	3,118	MWh	0.000555	2	0.000555	2
45	IRM - PV	7,339	MWh	0.000229	2	0.000229	2
46	IRM - SV	51,246	MWh	0.000104	5	0.000104	5
47	IRM - TV	63,460	MWh	0	0	0	0
48	Nuclear Decommissioning	125,163	MWh	0.000882	110	0.000882	110
49	Energy Waste Reduction	23	Meters	1,237.99	345	1,237.99	345
50	LIEAF	23	Meters	0.88	0	0.88	0
51	Distribution Surcharges	125,163	MWh	0.37¢	464	0.37¢	464
52							
53	Total Full Service Distribution	125,163	MWh	1.02¢	1,273	1.16¢	1,446
54	Total Full Service R1.1	125,163	MWh	6.59¢	8,244	6.86¢	8,580

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Alternative Metal Melting Rider - R1.1 (Cont'd)

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 40 of 58

Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
55	Choice Distribution						
56	Capacity						
57	Energy						
58	Secondary						
59	First 100 Hours Use	0	MWh	0.00706	0	0.01789	0
60	Excess Hours Use	0	MWh	0.00267	0	0.00676	0
61	Primary						
62	First 100 Hours Use	0	MWh	0.00525	0	0.01330	0
63	Excess Hours Use	0	MWh	0.00191	0	0.00484	0
64	Subtransmission						
65	First 100 Hours Use	0	MWh	0.00512	0	0.01297	0
66	Excess Hours Use	0	MWh	0.00178	0	0.00451	0
67	Transmission						
68	First 100 Hours Use	0	MWh	0.00434	0	0.01100	0
69	Excess Hours Use	0	MWh	0.00144	0	0.00365	0
70	Total Capacity	0	MWh				0
71							
72	Distribution Charges						
73	Secondary						
74	First 100 Hours Use	0	MWh	0.05288	0	0.06156	0
75	Excess Hours Use	0	MWh	0.05288	0	0.06156	0
76	Primary						
77	First 100 Hours Use	0	MWh	0.01832	0	0.02015	0
78	Excess Hours Use	0	MWh	0.01832	0	0.02015	0
79	Subtransmission						
80	First 100 Hours Use	0	MWh	0.00677	0	0.00532	0
81	Excess Hours Use	0	MWh	0.00677	0	0.00532	0
82	Transmission						
83	First 100 Hours Use	0	MWh	0.00274	0	0.00600	0
84	Excess Hours Use	0	MWh	0.00274	0	0.00600	0
85							
86	Substation Credit						
87	Energy	0	MWh	(0.00300)	0	(0.00300)	0
88	Distribution System	0	MWh		0		0
89							
90	IRM - DV	0	MWh	0.000555	0	0.000555	0
91	IRM - PV	0	MWh	0.000229	0	0.000229	0
92	IRM - SV	0	MWh	0.000104	0	0.000104	0
93	IRM - TV	0	MWh	0	0	0	0
94	Nuclear Decommissioning	0	MWh	0.000882	0	0.000882	0
95	Energy Optimization	0	Meters	1,237.99	0	1,237.99	0
96	LIEAF	0	Meters	0.88	0	0.88	0
97	Distribution Surcharges	0	MWh		0		0
98							
99	Total Choice R1.1	0	MWh		0		0
100							
101	Total R1.1	125,163	MWh	6.59¢	8,244	6.86¢	8,580
102	Increase/Decrease (\$)						336

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Electric Process Heat Rider - R1.2

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 41 of 58

Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d) Revenue (\$000)	(e) Proposed	(f) Revenue (\$000)
	Full Service Power Supply	<u>Quantity</u>	<u>Units</u>	<u>Rate</u>	<u>Revenue (\$000)</u>	<u>Rate</u>	<u>Revenue (\$000)</u>
	Capacity						
1	<u>Energy</u>						
2	Secondary						
3	First 100 Hours Use	12,311	MWh	0.00706	87	0.01789	220
4	Excess Hours Use	22,552	MWh	0.00267	60	0.00676	153
5	Primary						
6	First 100 Hours Use	81,851	MWh	0.00525	430	0.01330	1,089
7	Excess Hours Use	203,438	MWh	0.00191	389	0.00484	984
8	Subtransmission						
9	First 100 Hours Use	6,424	MWh	0.00512	33	0.01297	83
10	Excess Hours Use	20,884	MWh	0.00178	37	0.00451	94
11	Transmission						
12	First 100 Hours Use	0	MWh	0.00434	0	0.01100	0
13	Excess Hours Use	0	MWh	0.00144	0	0.00365	0
14	Total Capacity	347,461	MWh		1,035		2,623
15							
16	Non-Capacity						
17	<u>Energy</u>	347,461	MWh	0.05251	18,245	0.04892	16,997
18	Power Supply Subtotal	347,461			19,281		19,620
19							
20	PSCR	347,461	MWh	0.00000	0	0.00000	0
21	REPS	156	Cust.	0.00	0	0.00	0
22	Total Full Service Power Supply	347,461	MWh	5.55¢	19,281	5.65¢	19,620
23							
24	Full Service Distribution	<u>Quantity</u>	<u>Units</u>				
25							
26	<u>Distribution Charges</u>						
27	Secondary						
28	First 100 Hours Use	12,311	MWh	0.05288	651	0.06156	758
29	Excess Hours Use	22,552	MWh	0.05288	1,193	0.06156	1,388
30	Primary						
31	First 100 Hours Use	81,851	MWh	0.01832	1,500	0.02015	1,649
32	Excess Hours Use	203,438	MWh	0.01832	3,727	0.02015	4,099
33	Subtransmission						
34	First 100 Hours Use	6,424	MWh	0.00677	43	0.00532	34
35	Excess Hours Use	20,884	MWh	0.00677	141	0.00532	111
36	Transmission						
37	First 100 Hours Use	0	MWh	0.00274	0	0.00600	0
38	Excess Hours Use	0	MWh	0.00274	0	0.00600	0
39							
40	<u>Substation Credit</u>						
41	Energy	0	MWh	(0.00300)	0	(0.00300)	0
42	Distribution System	347,461	MWh	2.09¢	7,255	2.31¢	8,040
43							
44	IRM - DV	34,864	MWh	0.000555	19	0.000555	19
45	IRM - PV	285,289	MWh	0.000229	65	0.000229	65
46	IRM - SV	27,308	MWh	0.000104	3	0.000104	3
47	IRM - TV	0	MWh	0	0	0	0
48	Nuclear Decommissioning	347,461	MWh	0.000882	306	0.000882	306
49	Energy Waste Reduction	180	Meters	1,237.99	2,676	1,237.99	2,676
50	LIEAF	180	Meters	0.88	2	0.88	2
51	Distribution Surcharges	347,461	MWh	0.88¢	3,072	0.88¢	3,072
52							
53	Total Full Service Distribution	347,461	MWh	2.97¢	10,327	3.20¢	11,111
54	Total Full Service R1.2	347,461	MWh	8.52¢	29,608	8.84¢	30,732

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Electric Process Heat Rider - R1.2 (Cont'd)

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 42 of 58

Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d)	(e) Proposed	(f)
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
55	Choice Distribution						
56	Capacity						
57	Energy						
58	Secondary						
59	First 100 Hours Use	0	MWh	0.00706	0	0.01789	0
60	Excess Hours Use	0	MWh	0.00267	0	0.00676	0
61	Primary						
62	First 100 Hours Use	0	MWh	0.00525	0	0.01330	0
63	Excess Hours Use	0	MWh	0.00191	0	0.00484	0
64	Subtransmission						
65	First 100 Hours Use	0	MWh	0.00512	0	0.01297	0
66	Excess Hours Use	0	MWh	0.00178	0	0.00451	0
67	Transmission						
68	First 100 Hours Use	0	MWh	0.00434	0	0.01100	0
69	Excess Hours Use	0	MWh	0.00144	0	0.00365	0
70	Total Capacity	0	MWh				0
71	Distribution Charges						
72	Secondary						
73	First 100 Hours Use	0	MWh	0.05288	0	0.06156	0
74	Excess Hours Use	0	MWh	0.05288	0	0.06156	0
75	Primary						
76	First 100 Hours Use	5,269	MWh	0.01832	97	0.02015	106
77	Excess Hours Use	17,116	MWh	0.01832	314	0.02015	345
78	Subtransmission						
79	First 100 Hours Use	0	MWh	0.00677	0	0.00532	0
80	Excess Hours Use	0	MWh	0.00677	0	0.00532	0
81	Transmission						
82	First 100 Hours Use	0	MWh	0.00274	0	0.00600	0
83	Excess Hours Use	0	MWh	0.00274	0	0.00600	0
84							
85	Substation Credit						
86	Energy			(0.00300)	0	(0.00300)	0
87	Distribution System	22,385	MWh	1.83¢	410	2.01¢	451
88							
89	IRM - DV	0	MWh	0.000555	0	0.000555	0
90	IRM - PV	22,385	MWh	0.000229	5	0.000229	5
91	IRM - SV	0	MWh	0.000104	0	0.000104	0
92	IRM - TV	0	MWh	0	0	0	0
93	Nuclear Decommissioning	22,385	MWh	0.000882	20	0.000882	20
94	Energy Waste Reduction	6	Meters	1,237.99	83	1,237.99	83
95	LIEAF	6	Meters	0.88	0	0.88	0
96	Distribution Surcharges	22,385	MWh	0.48¢	108	0.48¢	108
97							
98	Total Choice Distribution R1.2	22,385	MWh	2.31¢	518	2.50¢	559
99							
100	Total R1.2	369,846	MWh	8.15¢	30,125	8.46¢	31,291
101	Increase/Decrease (\$)						1,165

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Parallel Operation And Standby Service Rider - R3
All Voltages

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 43 of 58

Line No.	(a) Description	(b) Billing Determinants Quantity Units	(c) Present Rate	(d) Present Revenue (\$000)	(e) Proposed Rate	(f) Proposed Revenue (\$000)
	Full Service Power Supply					
1	Station Power					
2	Capacity					
3	Administrative Charge	7,386 MWh	0.00000	0	0.00000	0
4	Station Power Capacity	7,386 MWh		0		0
5						
6	Non-Capacity					
7	MISO Energy Charge	7,386 MWh	0.03935	291	0.03935	291
8	Net Trans MISO MKT	7,386 MWh	0.00767	57	0.00769	57
9	Administrative Charge	7,386 MWh	0.00000	0	0.00000	0
10	Station Power PS Subtotal	7,386 MWh		347		347
11						
12	Standard R3					
13	Capacity					
14	<u>Power Supply Demand</u>					
15	Generation Reservation Fee	111,811 kW	0.13	15	0.33	37
16	Daily Demand	1,519,268 kW	0.36	547	0.92	1,395
17	Maintenance Demand	84,577 kW	0.18	15	0.46	39
18						
19						
20						
21						
22						
23	<u>Energy</u>					
24	Secondary	2,502 MWh	0.01010	25	0.02605	65
25	Primary Total	64,300 MWh	0.00000	0	0.00000	0
26		66,802 MWh				
27						
28						
29						
30						
31	Standard R3 Capacity	66,802 MWh		602		1,537
32						
33	Non-Capacity					
34	<u>Power Supply Demand</u>					
35	Generation Reservation Fee	111,811 kW	0.48	54	0.30	34
36	Daily Demand	1,519,268 kW	1.33	2,021	0.83	1,268
37	Maintenance Demand	84,577 kW	0.67	57	0.42	35
38						
39	<u>Energy</u>					
40	Secondary	2,502 MWh	0.07096	178	0.05870	147
41	Primary Total	64,300 MWh	0.04890	3,144	0.05016	3,225
42	Primary Off-Peak Discount	48,273 MWh	(0.010000)	(483)	(0.010000)	(483)
42						
43	<u>Voltage Level Discount</u>					
44	Subtransmission	24,083 MWh	(0.00062)	(15)	(0.00064)	(16)
45	Transmission	17,970 MWh	(0.00138)	(25)	(0.00143)	(26)
46	Standard R3 PS Subtotal	66,802		5,532		5,722
47						
48	PSCR	66,802 MWh	0.00000	0	0.00000	0
49	REPS	40 Cust.	0.00	0	0.00	0
50	Total Full Service Power Supply	74,189 MWh	7.93¢	5,880	8.18¢	6,069

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Parallel Operation And Standby Service Rider - R3 (Cont'd)
All Voltages

Case No.: U-21534
 Exhibit: A-16
 Schedule: F3 Revised
 Witness: A. Willis
 Page: 44 of 58

Line No.	(a) Description	(b) Billing Determinants	(c) Present	(d)	(e) Proposed	(f)
51	Full Service Distribution	<u>Quantity</u> <u>Units</u>				
52	<u>Service Charge</u>					
53	Secondary	13 Cust.	70	11	70	11
54	Service Charge - PV	14 Cust.	70	12	70	12
55	Service Charge - SV	12 Cust.	375	54	375	54
56	Service Charge - TV	1 Cust.	375	5	375	5
57	<u>Distribution Charges</u>					
58	Secondary	15,050 kW	13.22	199	15.39	232
59		2,502 MWh	0.05288	132	0.06156	154
60	Primary	78,089 kW	6.15	480	6.66	520
61		22,247 MWh				
62	Subtransmission	483,801 kW	1.96	948	1.82	881
63		24,083 MWh				
64	Transmission	92,427 kW	0.86	79	0.99	92
65		17,970 MWh				
66	<u>Substation Credit</u>					
67	Demand	101,092 kW	(0.30)	(30)	(0.30)	(30)
68	Energy	8,892 MWh	(0.00040)	(4)	(0.00040)	(4)
69	Distribution System	66,802 MWh	2.82¢	1,886	2.88¢	1,925
70						
71	IRM - DV	2,502 MWh	0.000595	1	0.000595	1
72	IRM - PV	78,089 kW	0.0727	6	0.072700	6
73	IRM - SV	483,801 kW	0.0312	15	0.031200	15
74	IRM - TV	92,427 kW	0.0000	0	0.000000	0
75	Nuclear Decommissioning	66,802 MWh	0.000882	59	0.000882	59
76	Energy Waste Reduction	46 Meters	1,237.99	678	1,237.99	678
77	LIEAF	46 Meters	0.88	0	0.88	0
78	Distribution Surcharges	66,802 MWh	1.14¢	760	1.14¢	760
79						
80	Total Full Service Distribution	66,802 MWh	3.96¢	2,646	4.02¢	2,685
81	Total Full Service R3	74,189 MWh	11.49¢	8,526	11.80¢	8,754
82	Increase/Decrease (\$)					229

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Interruptible Supply Rider - R10
All Voltages

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 45 of 58

Line No.	(a) Description	(b) Billing Determinants	(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
1	Full Service Power Supply					
2	Capacity					
3	Administrative Charge	998,081 MWh	0.00000	0	0.00000	0
4	Total Capacity	998,081 MWh				
5	Non-Capacity					
6	Administrative Charge	998,081 MWh	0.00000	0	0.00000	0
7	MISO Energy Charge	998,081 MWh	0.03935	39,274	0.03935	39,274
8	Net Trans MISO MKT	998,081 MWh	0.00767	7,655	0.00769	7,674
9	Voltage Level Service Adder					
10	Primary	30,650 MWh	5.50%	79	5.50%	79
11	Subtransmission	21,262 MWh	3.73%	37	3.73%	37
12	Transmission	946,169 MWh	1.56%	694	1.56%	694
13	Power Supply Subtotal	998,081 MWh		47,740		47,759
14	REPS	0 meters	0.00	0	0.00	0
15	Total Full Service Power Supply	998,081 MWh	4.78¢	47,740	4.79¢	47,759
16	Full Service Distribution					
17		Quantity Units				
18	Service Charge - PV	12 Cust.	70	10	70	10
19	Service Charge - SV	8 Cust.	375	36	375	36
20	Service Charge - TV	33 Cust.	375	149	375	149
21	Distribution Charges					
22	Primary	178,736 kW	6.15	1,099	6.66	1,191
23		30,650 MWh				
24	Subtransmission	65,584 kW	1.96	129	1.82	119
25		21,262 MWh				
26	Transmission	3,790,403 kW	0.86	3,260	0.99	3,757
27		946,169 MWh				
28	Substation Credit					
29	Demand	1,250,515 kW	(0.30)	(375)	(0.30)	(375)
30	Energy	144,780 MWh	(0.0004)	(58)	(0.0004)	(58)
31	Distribution System	998,081 MWh	0.43¢	4,249	0.48¢	4,829
32	IRM - PV	178,736 kW	0.0727	13	0.0727	13
33	IRM - SV	65,584 kW	0.0312	2	0.0312	2
34	IRM - TV	3,790,403 kW	0	0	0	0
35	Nuclear Decommissioning	998,081 MWh	0.000882	880	0.000882	880
36	Energy Waste Reduction	0 Meters	1,237.99	0	1,237.99	0
37	LIEAF	0 Meters	0.88	0	0.88	0
38	Distribution Surcharges	998,081 MWh	0.09¢	895	0.09¢	895
39	Total Full Service Distribution	998,081 MWh	0.52¢	5,145	0.57¢	5,724
40	Total Full Service R10	998,081 MWh	5.30¢	52,885	5.36¢	53,484

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Interruptible Supply Rider - R10 (Cont'd)
All Voltages

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: A. Willis
Page: 46 of 58

Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d) Present	(e) Proposed	(f) Proposed
		Quantity	Units	Rate	Revenue (\$000)	Rate	Revenue (\$000)
45	Choice Distribution						
46	Capacity						
47	Administrative Charge	0	MWh	0.00000		0.00000	0
48	Total Capacity	0	MWh				0
49							
50	Service Charge - PV	0	Cust.	70	0	70	0
51	Service Charge - SV	0	Cust.	375	0	375	0
52	Service Charge - TV	0	Cust.	375	0	375	0
53	<u>Distribution Charges</u>						
54	Primary	0	kW	6.15	0	6.66	0
55							
56	Subtransmission	0	kW	1.96	0	1.82	0
57							
58	Transmission	0	kW	0.86	0	0.99	0
59							
60	<u>Substation Credit</u>						
61	Demand	0	kW	(0.30)	0	(0.30)	0
62	Energy	0	MWh	(0.0004)	0	(0.0004)	0
63	Distribution System	0	MWh		0		0
64							
65	IRM - PV	0	kW	0.0727	0	0.0727	0
66	IRM - SV	0	kW	0.0312	0	0.0312	0
67	IRM - TV	0	kW	0	0	0	0
68	Nuclear Decommissioning			0.000882	0	0.000882	0
69	Energy Waste Reduction			1,237.99	0	1,237.99	0
70	LIEAF	0	Meters	0.88	0	0.88	0
71	Distribution Surcharges				0		0
72							
73	Total Choice Distribution R10	0	MWh		0		0
74							
75	Total R10	998,081	MWh	5.30¢	52,885	5.36¢	53,484
76	Increase/Decrease (\$)						599

Line No.	(a) Description	(b) Billing Determinants		(c)	(d) Present	(e)	(f)	(g) Proposed	(h) Non-Capacity	(i) Capacity	(j)	
					Rate	Non-Capacity	Capacity	Rate	Capacity	Capacity		
		Quantity	Units		(\$/luminaire/ mth)	Energy	Energy	Revenue	Energy	Energy	Revenue	
					(¢/kWh)	(¢/kWh)	(¢/kWh)	(\$000)	(\$/luminaire/ mth)	(¢/kWh)	(¢/kWh)	(\$000)
1	Overhead											
2	Mercury Vapor											
3	100 W	0	Lamps		15.04	4.46	0.00	0	16.13	4.66	0.00	0
4	175 W	3,129	Lamps		18.68	4.46	0.00	825	20.05	4.66	0.00	882
5	250 W	1	Lamps		22.32	4.46	0.00	0	23.98	4.66	0.00	0
6	400 W	54	Lamps		29.40	4.46	0.00	24	31.61	4.66	0.00	25
7	1,000 W	3	Lamps		60.24	4.46	0.00	3	64.81	4.66	0.00	3
8												
9	High Pressure Sodium Vapor											
10	100 W	3,245	Lamps		14.00	4.46	0.00	627	15.02	4.66	0.00	671
11	150 W	1	Lamps		16.71	4.46	0.00	0	17.94	4.66	0.00	0
12	250 W	399	Lamps		21.49	4.46	0.00	126	23.09	4.66	0.00	134
13	360 W	0	Lamps		25.11	4.46	0.00	0	27.00	4.66	0.00	0
14	400 W	31	Lamps		26.42	4.46	0.00	13	28.42	4.66	0.00	13
15	1,000 W	4	Lamps		53.23	4.46	0.00	3	57.33	4.66	0.00	4
16												
17	Metal Halide											
18	100 W	0	Lamps		14.03	4.46	0.00	0	15.06	4.66	0.00	0
19	150 W	0	Lamps		16.77	4.46	0.00	0	18.01	4.66	0.00	0
20	175 W	0	Lamps		18.14	4.46	0.00	0	19.49	4.66	0.00	0
21	250 W	0	Lamps		22.25	4.46	0.00	0	23.91	4.66	0.00	0
22	320 W	0	Lamps		26.09	4.46	0.00	0	28.04	4.66	0.00	0
23	400 W	0	Lamps		30.48	4.46	0.00	0	32.76	4.66	0.00	0
24	1,000 W	1	Lamps		63.38	4.46	0.00	1	68.16	4.66	0.00	1
25		0										
26	LED	0										
27	20 - 29 W	0	Lamps		11.20	4.46	0.00	0	12.00	4.66	0.00	0
28	30 - 39 W	0	Lamps		11.79	4.46	0.00	0	12.62	4.66	0.00	0
29	40 - 49 W	0	Lamps		12.37	4.46	0.00	0	13.25	4.66	0.00	0
30	50 - 59 W	722	Lamps		12.95	4.46	0.00	120	13.87	4.66	0.00	128
31	60 - 69 W	1,458	Lamps		13.53	4.46	0.00	254	14.49	4.66	0.00	272
32	70 - 79 W	11	Lamps		14.12	4.46	0.00	2	15.13	4.66	0.00	2
33	80 - 89 W	0	Lamps		14.70	4.46	0.00	0	15.75	4.66	0.00	0
34	90 - 99 W	0	Lamps		15.28	4.46	0.00	0	16.38	4.66	0.00	0
35	100 - 109 W	0	Lamps		15.86	4.46	0.00	0	17.01	4.66	0.00	0
36	110 - 119 W	4	Lamps		16.45	4.46	0.00	1	17.63	4.66	0.00	1
37	120 - 129 W	0	Lamps		17.03	4.46	0.00	0	18.26	4.66	0.00	0
38	130 - 139 W	140	Lamps		17.61	4.46	0.00	33	18.88	4.66	0.00	35
39	140 - 149 W	4	Lamps		18.14	4.46	0.00	1	19.45	4.66	0.00	1
40	150 - 159 W	0	Lamps		18.66	4.46	0.00	0	20.02	4.66	0.00	0
41	160 - 169 W	0	Lamps		19.18	4.46	0.00	0	20.58	4.66	0.00	0
42	170 - 179 W	0	Lamps		19.71	4.46	0.00	0	21.14	4.66	0.00	0
43	180 - 189 W	0	Lamps		20.23	4.46	0.00	0	21.71	4.66	0.00	0
44	190 - 199 W	0	Lamps		20.75	4.46	0.00	0	22.27	4.66	0.00	0
45	200 - 209 W	0	Lamps		21.28	4.46	0.00	0	22.83	4.66	0.00	0
46	210 - 219 W	2	Lamps		21.80	4.46	0.00	1	23.39	4.66	0.00	1
47	220 - 229 W	0	Lamps		22.32	4.46	0.00	0	23.95	4.66	0.00	0
48	230 - 239 W	5	Lamps		22.85	4.46	0.00	2	24.52	4.66	0.00	2
49	240 - 249 W	0	Lamps		23.37	4.46	0.00	0	25.09	4.66	0.00	0
50	250 - 259 W	0	Lamps		23.89	4.46	0.00	0	25.65	4.66	0.00	0
51	260 - 269 W	0	Lamps		24.42	4.46	0.00	0	26.21	4.66	0.00	0
52	270 - 279 W	0	Lamps		24.94	4.46	0.00	0	26.78	4.66	0.00	0
53	280 - 289 W	8	Lamps		25.47	4.46	0.00	3	27.34	4.66	0.00	3
54	290 - 299 W	14	Lamps		25.99	4.46	0.00	5	27.90	4.66	0.00	5
55	300 - 309 W	0	Lamps		26.51	4.46	0.00	0	28.47	4.66	0.00	0
56	310 - 319 W	0	Lamps		27.04	4.46	0.00	0	29.03	4.66	0.00	0
57	320 - 329 W	0	Lamps		27.56	4.46	0.00	0	29.59	4.66	0.00	0
58	330 - 339 W	0	Lamps		28.08	4.46	0.00	0	30.15	4.66	0.00	0
59	340 - 349 W	0	Lamps		28.61	4.46	0.00	0	30.72	4.66	0.00	0
60	350 - 359 W	0	Lamps		29.13	4.46	0.00	0	31.28	4.66	0.00	0
61	360 - 369 W	0	Lamps		29.65	4.46	0.00	0	31.84	4.66	0.00	0
62	370 - 379 W	0	Lamps		30.18	4.46	0.00	0	32.41	4.66	0.00	0
63	380 - 389 W	0	Lamps		30.70	4.46	0.00	0	32.97	4.66	0.00	0
64	390 - 399 W	0	Lamps		31.22	4.46	0.00	0	33.53	4.66	0.00	0

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: R. A. Bellini
Page: 48 of 58

Line No.	(a) Description	(b) Billing Determinants		(c) Present				(d)	(e)	(f)	(g)	(h) Proposed	(i)	(j)
				Rate	Non-Capacity	Capacity					Rate	Non-Capacity	Capacity	
		Quantity	Units	(\$/luminaire/ mth)	Energy (¢/kWh)	Energy (¢/kWh)	Revenue (\$000)				(\$/luminaire/ mth)	Energy (¢/kWh)	Energy (¢/kWh)	Revenue (\$000)
65	Underground													
66	Mercury Vapor													
67	100 W	0	Lamps	27.60	4.46	0.00	0				27.51	4.66	0.00	0
68	175 W	1	Lamps	30.35	4.46	0.00	0				30.20	4.66	0.00	0
69	250 W	0	Lamps	35.65	4.46	0.00	0				35.43	4.66	0.00	0
70	400 W	0	Lamps	46.25	4.46	0.00	0				45.93	4.66	0.00	0
71	1,000 W	0	Lamps	86.55	4.46	0.00	0				85.76	4.66	0.00	0
72														
73	High Pressure Sodium Vapor													
74	70 W	0	Lamps	24.09	4.46	0.00	0				24.02	4.66	0.00	0
75	100 W	1	Lamps	24.86	4.46	0.00	0				24.76	4.66	0.00	0
76	150 W	0	Lamps	26.49	4.46	0.00	0				26.35	4.66	0.00	0
77	250 W	0	Lamps	29.75	4.46	0.00	0				29.53	4.66	0.00	0
78	400 W	0	Lamps	34.64	4.46	0.00	0				34.30	4.66	0.00	0
79	1,000 W	0	Lamps	54.21	4.46	0.00	0				53.37	4.66	0.00	0
80														
81	Metal Halide													
82	100 W	0	Lamps	30.54	4.46	0.00	0				24.76	4.66	0.00	0
83	150 W	0	Lamps	34.29	4.46	0.00	0				26.35	4.66	0.00	0
84	175 W	0	Lamps	36.17	4.46	0.00	0				27.15	4.66	0.00	0
85	250 W	0	Lamps	41.79	4.46	0.00	0				29.53	4.66	0.00	0
86	400 W	0	Lamps	53.05	4.46	0.00	0				34.30	4.66	0.00	0
87	1,000 W	0	Lamps	98.08	4.46	0.00	0				101.94	4.66	0.00	0
88														
89	LED													
90	20 - 29 W	0	Lamps	25.22	4.46	0.00	0				25.20	4.66	0.00	0
91	30 - 39 W	2	Lamps	25.66	4.46	0.00	1				25.63	4.66	0.00	1
92	40 - 49 W	0	Lamps	26.10	4.46	0.00	0				26.07	4.66	0.00	0
93	50 - 59 W	0	Lamps	26.55	4.46	0.00	0				26.51	4.66	0.00	0
94	60 - 69 W	0	Lamps	27.00	4.46	0.00	0				26.95	4.66	0.00	0
95	70 - 79 W	74	Lamps	27.41	4.46	0.00	25				27.36	4.66	0.00	25
96	80 - 89 W	0	Lamps	27.84	4.46	0.00	0				27.78	4.66	0.00	0
97	90 - 99 W	0	Lamps	28.25	4.46	0.00	0				28.18	4.66	0.00	0
98	100 - 109 W	0	Lamps	28.66	4.46	0.00	0				28.58	4.66	0.00	0
99	110 - 119 W	0	Lamps	29.09	4.46	0.00	0				29.01	4.66	0.00	0
100	120 - 129 W	0	Lamps	29.49	4.46	0.00	0				29.40	4.66	0.00	0
101	130 - 139 W	1	Lamps	29.89	4.46	0.00	0				29.79	4.66	0.00	0
102	140 - 149 W	0	Lamps	30.27	4.46	0.00	0				30.17	4.66	0.00	0
103	150 - 159 W	0	Lamps	30.65	4.46	0.00	0				30.54	4.66	0.00	0
104	160 - 169 W	0	Lamps	31.03	4.46	0.00	0				30.92	4.66	0.00	0
105	170 - 179 W	0	Lamps	31.41	4.46	0.00	0				31.29	4.66	0.00	0
106	180 - 189 W	0	Lamps	31.79	4.46	0.00	0				31.66	4.66	0.00	0
107	190 - 199 W	0	Lamps	32.17	4.46	0.00	0				32.04	4.66	0.00	0
108	200 - 209 W	0	Lamps	32.56	4.46	0.00	0				32.41	4.66	0.00	0
109	210 - 219 W	0	Lamps	32.94	4.46	0.00	0				32.79	4.66	0.00	0
110	220 - 229 W	0	Lamps	33.32	4.46	0.00	0				33.16	4.66	0.00	0
111	230 - 239 W	0	Lamps	33.70	4.46	0.00	0				33.53	4.66	0.00	0
112	240 - 249 W	0	Lamps	34.08	4.46	0.00	0				33.91	4.66	0.00	0
113	250 - 259 W	0	Lamps	34.47	4.46	0.00	0				34.28	4.66	0.00	0
114	260 - 269 W	0	Lamps	34.85	4.46	0.00	0				34.66	4.66	0.00	0
115	270 - 279 W	0	Lamps	35.23	4.46	0.00	0				35.03	4.66	0.00	0
116	280 - 289 W	0	Lamps	35.61	4.46	0.00	0				35.41	4.66	0.00	0
117	290 - 299 W	0	Lamps	35.99	4.46	0.00	0				35.78	4.66	0.00	0
118	300 - 309 W	0	Lamps	36.37	4.46	0.00	0				36.15	4.66	0.00	0
119	310 - 319 W	0	Lamps	36.76	4.46	0.00	0				36.52	4.66	0.00	0
120	320 - 329 W	0	Lamps	37.14	4.46	0.00	0				36.90	4.66	0.00	0
121	330 - 339 W	0	Lamps	37.52	4.46	0.00	0				37.27	4.66	0.00	0
122	340 - 349 W	0	Lamps	37.90	4.46	0.00	0				37.64	4.66	0.00	0
123	350 - 359 W	0	Lamps	38.28	4.46	0.00	0				38.02	4.66	0.00	0
124	360 - 369 W	0	Lamps	38.66	4.46	0.00	0				38.39	4.66	0.00	0
125	370 - 379 W	0	Lamps	39.05	4.46	0.00	0				38.76	4.66	0.00	0
126	380 - 389 W	0	Lamps	39.43	4.46	0.00	0				39.13	4.66	0.00	0
127	390 - 399 W	0	Lamps	39.81	4.46	0.00	0				39.51	4.66	0.00	0
128														
129	Lamp Total	9,315	Lamps				2,070							2,212
130														
131	PSCR	6,023	MWh	\$ -			0				\$ -			0
132														
133	Additional Light Credit	0	Lamps	-97.92			0				-97.92			0
134	Post Charge	0	Posts	82.56			0				84.96			0
135														
136	Other Charges													
137		Number of Poles		\$ /Pole/Year							\$ /Pole/Year			
138	New Poles	1,608	Poles	24.48			39				24.48			39
139	Subtotal						2,109							2,251
140	IRM	6,023	MWh	0.005352			32				0.005352			32
141	Nuclear Decommissioning	6,023	MWh	0.000882			5				0.000882			5
142	Subtotal	9,315	Lamps				2,147							2,288
143														
144		Investment		Carrying Charge/Year							Carrying Charge/Year			
145	Special Facilities	10,839		-18%			(2)				-18%			(2)
146	Subtotal	9,315	Lamps				2,145							2,286
147														
148	Energy Waste Reduction	6,023	MWh	0.002552			15				0.002552			15
149	REPS	8,680	Meters	0.00%			0							0
150	Total Residential D9	6,023	MWh				2,160							2,302
151	Increase/Decrease (\$)													142

Line No.	(a) Description	(b) Billing Determinants		(c)	(d) Present	(e) Capacity	(f) Revenue	(g) Non-Capacity	(h) Capacity	(i) Capacity	(j) Revenue
					Rate	Energy	Energy	Rate	Energy	Energy	Revenue
		Quantity	Units		(\$/luminaire/ mth)	(¢/kWh)	(¢/kWh)	(\$/luminaire/ mth)	(¢/kWh)	(¢/kWh)	(\$000)
1	Overhead										
2	Mercury Vapor										
3	100 W	0	Lamps		15.04	4.46	0.00	0	16.13	4.66	0.00
4	175 W	3,454	Lamps		18.68	4.46	0.00	910	20.05	4.66	0.00
5	250 W	113	Lamps		22.32	4.46	0.00	37	23.98	4.66	0.00
6	400 W	916	Lamps		29.40	4.46	0.00	400	31.61	4.66	0.00
7	1,000 W	99	Lamps		60.24	4.46	0.00	91	64.81	4.66	0.00
8											
9	High Pressure Sodium Vapor										
10	100 W	2,248	Lamps		14.00	4.46	0.00	435	15.02	4.66	0.00
11	150 W	0	Lamps		16.71	4.46	0.00	0	17.94	4.66	0.00
12	250 W	3,950	Lamps		21.49	4.46	0.00	1,244	23.09	4.66	0.00
13	360 W	0	Lamps		25.11	4.46	0.00	0	27.00	4.66	0.00
14	400 W	2,086	Lamps		26.42	4.46	0.00	843	28.42	4.66	0.00
15	1,000 W	59	Lamps		53.23	4.46	0.00	50	57.33	4.66	0.00
16											
17	Metal Halide										
18	100 W	0	Lamps		14.03	4.46	0.00	0	15.06	4.66	0.00
19	150 W	0	Lamps		16.77	4.46	0.00	0	18.01	4.66	0.00
20	175 W	0	Lamps		18.14	4.46	0.00	0	19.49	4.66	0.00
21	250 W	0	Lamps		22.25	4.46	0.00	0	23.91	4.66	0.00
22	320 W	0	Lamps		26.09	4.46	0.00	0	28.04	4.66	0.00
23	400 W	3	Lamps		30.48	4.46	0.00	1	32.76	4.66	0.00
24	1,000 W	165	Lamps		63.38	4.46	0.00	158	68.16	4.66	0.00
25											
26	LED										
27	20 - 29 W	0	Lamps		11.20	4.46	0.00	0	12.00	4.66	0.00
28	30 - 39 W	9	Lamps		11.79	4.46	0.00	1	12.62	4.66	0.00
29	40 - 49 W	0	Lamps		12.37	4.46	0.00	0	13.25	4.66	0.00
30	50 - 59 W	1,909	Lamps		12.95	4.46	0.00	316	13.87	4.66	0.00
31	60 - 69 W	2,053	Lamps		13.53	4.46	0.00	358	14.49	4.66	0.00
32	70 - 79 W	230	Lamps		14.12	4.46	0.00	42	15.13	4.66	0.00
33	80 - 89 W	10	Lamps		14.70	4.46	0.00	2	15.75	4.66	0.00
34	90 - 99 W	0	Lamps		15.28	4.46	0.00	0	16.38	4.66	0.00
35	100 - 109 W	0	Lamps		15.86	4.46	0.00	0	17.01	4.66	0.00
36	110 - 119 W	6	Lamps		16.45	4.46	0.00	1	17.63	4.66	0.00
37	120 - 129 W	0	Lamps		17.03	4.46	0.00	0	18.26	4.66	0.00
38	130 - 139 W	2,438	Lamps		17.61	4.46	0.00	577	18.88	4.66	0.00
39	140 - 149 W	17	Lamps		18.14	4.46	0.00	4	19.45	4.66	0.00
40	150 - 159 W	0	Lamps		18.66	4.46	0.00	0	20.02	4.66	0.00
41	160 - 169 W	0	Lamps		19.18	4.46	0.00	0	20.58	4.66	0.00
42	170 - 179 W	0	Lamps		19.71	4.46	0.00	0	21.14	4.66	0.00
43	180 - 189 W	0	Lamps		20.23	4.46	0.00	0	21.71	4.66	0.00
44	190 - 199 W	0	Lamps		20.75	4.46	0.00	0	22.27	4.66	0.00
45	200 - 209 W	119	Lamps		21.28	4.46	0.00	35	22.83	4.66	0.00
46	210 - 219 W	467	Lamps		21.80	4.46	0.00	141	23.39	4.66	0.00
47	220 - 229 W	1	Lamps		22.32	4.46	0.00	0	23.95	4.66	0.00
48	230 - 239 W	1,186	Lamps		22.85	4.46	0.00	377	24.52	4.66	0.00
49	240 - 249 W	0	Lamps		23.37	4.46	0.00	0	25.09	4.66	0.00
50	250 - 259 W	0	Lamps		23.89	4.46	0.00	0	25.65	4.66	0.00
51	260 - 269 W	0	Lamps		24.42	4.46	0.00	0	26.21	4.66	0.00
52	270 - 279 W	0	Lamps		24.94	4.46	0.00	0	26.78	4.66	0.00
53	280 - 289 W	842	Lamps		25.47	4.46	0.00	302	27.34	4.66	0.00
54	290 - 299 W	1,592	Lamps		25.99	4.46	0.00	584	27.90	4.66	0.00
55	300 - 309 W	0	Lamps		26.51	4.46	0.00	0	28.47	4.66	0.00
56	310 - 319 W	0	Lamps		27.04	4.46	0.00	0	29.03	4.66	0.00
57	320 - 329 W	0	Lamps		27.56	4.46	0.00	0	29.59	4.66	0.00
58	330 - 339 W	0	Lamps		28.08	4.46	0.00	0	30.15	4.66	0.00
59	340 - 349 W	0	Lamps		28.61	4.46	0.00	0	30.72	4.66	0.00
60	350 - 359 W	0	Lamps		29.13	4.46	0.00	0	31.28	4.66	0.00
61	360 - 369 W	0	Lamps		29.65	4.46	0.00	0	31.84	4.66	0.00
62	370 - 379 W	0	Lamps		30.18	4.46	0.00	0	32.41	4.66	0.00
63	380 - 389 W	0	Lamps		30.70	4.46	0.00	0	32.97	4.66	0.00
64	390 - 399 W	8	Lamps		31.22	4.46	0.00	4	33.53	4.66	0.00

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: R. A. Bellini
Page: 50 of 58

Line No.	(a) Description	(b) Billing Determinants		(c) Present				(d)	(e)	(f)	(g) Proposed				(h)	(i)	(j)

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
Municipal Street Lighting - E1 Option I - Company Owned Overhead

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: R. A. Bellini
Page: 51 of 58

Line No.	(a) Description	(b) Billing Determinants		(c)	(d) Present	(e) Present	(f) Present	(g)	(h) Proposed	(i) Proposed	(j) Proposed
		Quantity	Units	Rate (\$/luminaire/ mth)	Non-Capacity Energy (\$/kWh)	Capacity Energy (\$/kWh)	Revenue (\$000)	Rate (\$/luminaire/ mth)	Non-Capacity Energy (\$/kWh)	Capacity Energy (\$/kWh)	Revenue (\$000)
1	Overhead										
2	Mercury Vapor										
3	100 W	97	Lamps	25.34	4.46	0.00	32	27.80	4.66	0.00	35
4	175 W	1,644	Lamps	31.35	4.46	0.00	681	34.43	4.66	0.00	745
5	250 W	0	Lamps	37.52	4.46	0.00	0	41.13	4.66	0.00	0
6	400 W	386	Lamps	49.56	4.46	0.00	261	54.52	4.66	0.00	285
7	1,000 W	0	Lamps	105.40	4.46	0.00	0	116.02	4.66	0.00	0
8											
9	High Pressure Sodium Vapor										
10	70 W	948	Lamps	18.86	4.46	0.00	231	20.69	4.66	0.00	252
11	100 W	5,337	Lamps	21.53	4.46	0.00	1,509	23.64	4.66	0.00	1,651
12	150 W	0	Lamps	25.87	4.46	0.00	0	28.08	4.66	0.00	0
13	250 W	2,049	Lamps	33.61	4.46	0.00	940	36.97	4.66	0.00	1,028
14	360 W	0	Lamps	42.05	4.46	0.00	0	43.17	4.66	0.00	0
15	400 W	0	Lamps	45.12	4.46	0.00	0	45.42	4.66	0.00	0
16	1,000 W	0	Lamps	82.64	4.46	0.00	0	79.23	4.66	0.00	0
17											
18	Metal Halide										
19	70 W	1	Lamps	24.48	4.46	0.00	0	26.83	4.66	0.00	0
20	100 W	1	Lamps	24.83	4.46	0.00	0	27.24	4.66	0.00	0
21	150 W	0	Lamps	30.17	4.46	0.00	0	33.11	4.66	0.00	0
22	175 W	10	Lamps	32.83	4.46	0.00	4	36.05	4.66	0.00	5
23	250 W	1	Lamps	40.84	4.46	0.00	1	44.87	4.66	0.00	1
24	320 W	0	Lamps	47.70	4.46	0.00	0	52.42	4.66	0.00	0
25	400 W	6	Lamps	55.53	4.46	0.00	4	61.05	4.66	0.00	5
26	1,000 W	1	Lamps	114.64	4.46	0.00	2	126.11	4.66	0.00	2
27											
28	De-Energized										
29	Mercury Vapor										
30	100 W	0	Lamps	16.33	4.46	0.00	0	17.81	4.66	0.00	0.000
31	175 W	1	Lamps	20.78	4.46	0.00	0	22.65	4.66	0.00	0.272
32	250 W	0	Lamps	25.32	4.46	0.00	0	0.00	4.66	0.00	0.000
33	400 W	0	Lamps	33.95	4.46	0.00	0	36.97	4.66	0.00	0.000
34	1,000 W	0	Lamps	78.36	4.46	0.00	0	78.36	4.66	0.00	0.000
35											
36	High Pressure Sodium Vapor										
37	70 W	0	Lamps	12.20	4.46	0.00	0	13.32	4.66	0.00	0.000
38	100 W	4	Lamps	14.18	4.46	0.00	1	15.46	4.66	0.00	0.742
39	150 W	0	Lamps	17.39	4.46	0.00	0	0.00	4.66	0.00	0.000
40	250 W	1	Lamps	23.02	4.46	0.00	0	25.07	4.66	0.00	0.301
41	360 W	0	Lamps	31.20	4.46	0.00	0	31.20	4.66	0.00	0.000
42	400 W	0	Lamps	31.42	4.46	0.00	0	0.00	4.66	0.00	0.000
43	1,000 W	0	Lamps	64.29	4.46	0.00	0	64.29	4.66	0.00	0.000
44											
45	LED										
46	60 - 69 W	0	Lamps	12.16	4.46	0.00	0	13.01	4.66	0.00	0.000
47											
48	Dusk-Midnight										
49	Mercury Vapor										
50	100 W	0	Lamps	24.28	4.46	0.00	0	26.74	4.66	0.00	0.000
51	175 W	0	Lamps	29.50	4.46	0.00	0	32.58	4.66	0.00	0.000
52	250 W	0	Lamps	34.87	4.46	0.00	0	38.48	4.66	0.00	0.000
53	400 W	0	Lamps	45.32	4.46	0.00	0	50.28	4.66	0.00	0.000
54	1,000 W	0	Lamps	103.94	4.46	0.00	0	103.94	4.66	0.00	0.000
55											
56	High Pressure Sodium Vapor										
57	70 W	0	Lamps	18.11	4.46	0.00	0	19.95	4.66	0.00	0.000
58	100 W	0	Lamps	20.47	4.46	0.00	0	22.58	4.66	0.00	0.000
59	150 W	0	Lamps	24.28	4.46	0.00	0	26.49	4.66	0.00	0.000
60	250 W	2	Lamps	30.96	4.46	0.00	1	34.32	4.66	0.00	0.882
61	360 W	0	Lamps	38.23	4.46	0.00	0	39.35	4.66	0.00	0.000
62	400 W	4	Lamps	40.88	4.46	0.00	2	41.18	4.66	0.00	2.153
63	1,000 W	0	Lamps	72.04	4.46	0.00	0	68.63	4.66	0.00	0.000
64											
65	LED										
66	130 - 139 W	5	Lamps	25.97	4.46	0.00	2	28.33	4.66	0.00	1.764
67	280 - 289 W	2	Lamps	36.07	4.46	0.00	1	39.93	4.66	0.00	1.012

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: R. A. Bellini
Page: 52 of 58

Line No.	(a) Description	(b) Billing Determinants	(c)	(d) Present	(e)	(f)	(g)	(h) Proposed	(i)	(j)	
				Rate (\$/luminaire/ mth)	Non-Capacity Energy (¢/kWh)	Capacity Energy (¢/kWh)	Revenue (\$000)	Rate (\$/luminaire/ mth)	Non-Capacity Energy (¢/kWh)	Capacity Energy (¢/kWh)	Revenue (\$000)
68	LED	Quantity Units									
69	20 - 29 W	0 Lamps		15.91	4.46	0.00	0	15.50	4.66	0.00	0
70	30 - 39 W	3 Lamps		16.65	4.46	0.00	1	16.78	4.66	0.00	1
71	40 - 49 W	73 Lamps		17.39	4.46	0.00	16	18.07	4.66	0.00	16
72	50 - 59 W	22,280 Lamps		18.12	4.46	0.00	5,067	19.36	4.66	0.00	5,409
73	60 - 69 W	36,373 Lamps		19.29	4.46	0.00	8,848	20.66	4.66	0.00	9,467
74	70 - 79 W	607 Lamps		20.46	4.46	0.00	157	21.96	4.66	0.00	169
75	80 - 89 W	1,685 Lamps		21.63	4.46	0.00	463	23.26	4.66	0.00	498
76	90 - 99 W	1,509 Lamps		22.80	4.46	0.00	439	24.56	4.66	0.00	472
77	100 - 109 W	90 Lamps		23.97	4.46	0.00	28	25.86	4.66	0.00	30
78	110 - 119 W	3 Lamps		25.14	4.46	0.00	1	27.16	4.66	0.00	1
79	120 - 129 W	58 Lamps		26.31	4.46	0.00	20	28.46	4.66	0.00	21
80	130 - 139 W	21,218 Lamps		27.40	4.46	0.00	7,496	29.76	4.66	0.00	8,121
81	140 - 149 W	165 Lamps		28.27	4.46	0.00	60	30.88	4.66	0.00	66
82	150 - 159 W	400 Lamps		29.13	4.46	0.00	151	31.23	4.66	0.00	162
83	160 - 169 W	108 Lamps		30.00	4.46	0.00	42	32.33	4.66	0.00	45
84	170 - 179 W	53 Lamps		30.86	4.46	0.00	21	33.42	4.66	0.00	23
85	180 - 189 W	9 Lamps		31.73	4.46	0.00	4	34.51	4.66	0.00	4
86	190 - 199 W	0 Lamps		32.59	4.46	0.00	0	35.61	4.66	0.00	0
87	200 - 209 W	150 Lamps		33.46	4.46	0.00	66	36.70	4.66	0.00	72
88	210 - 219 W	35 Lamps		34.32	4.46	0.00	16	37.68	4.66	0.00	17
89	220 - 229 W	0 Lamps		34.61	4.46	0.00	0	38.01	4.66	0.00	0
90	230 - 239 W	699 Lamps		34.90	4.46	0.00	323	38.33	4.66	0.00	353
91	240 - 249 W	5 Lamps		35.74	4.46	0.00	2	39.26	4.66	0.00	3
92	250 - 259 W	11 Lamps		36.58	4.46	0.00	5	40.18	4.66	0.00	6
93	260 - 269 W	0 Lamps		37.41	4.46	0.00	0	41.10	4.66	0.00	0
94	270 - 279 W	0 Lamps		38.25	4.46	0.00	0	42.03	4.66	0.00	0
95	280 - 289 W	771 Lamps		39.09	4.46	0.00	401	42.95	4.66	0.00	439
96	290 - 299 W	14 Lamps		39.93	4.46	0.00	7	43.87	4.66	0.00	8
97	300 - 309 W	15 Lamps		40.77	4.46	0.00	8	44.80	4.66	0.00	9
98	310 - 319 W	0 Lamps		41.61	4.46	0.00	0	45.73	4.66	0.00	0
99	320 - 329 W	4 Lamps		42.45	4.46	0.00	2	46.65	4.66	0.00	2
100	330 - 339 W	0 Lamps		43.29	4.46	0.00	0	47.58	4.66	0.00	0
101	340 - 349 W	0 Lamps		44.12	4.46	0.00	0	48.50	4.66	0.00	0
102	350 - 359 W	0 Lamps		44.96	4.46	0.00	0	49.43	4.66	0.00	0
103	360 - 369 W	0 Lamps		45.80	4.46	0.00	0	50.35	4.66	0.00	0
104	370 - 379 W	0 Lamps		46.64	4.46	0.00	0	51.28	4.66	0.00	0
105	380 - 389 W	0 Lamps		47.48	4.46	0.00	0	52.21	4.66	0.00	0
106	390 - 399 W	0 Lamps		48.32	4.46	0.00	0	53.13	4.66	0.00	0
107	Subtotal	96,838 Lamps					27,316				29,428
108											
109	PSCR	37,920 MWh		0			0	\$ -			0
110											
111	Multiple Lamp Discount	1,445 Lamps		(\$12.24)			(18)	-12.24			(18)
112	Subtotal	96,838 Lamps					27,298				29,411
113	IRM	37,920 MWh		0.005140			195	0.005140			195
114	Nuclear Decomm.	37,920 MWh		0.000882			33	0.000882			33
115	Subtotal	96,838 Lamps					27,527				29,639
116											
117	Energy Optimization	558 Meters		\$5.50			37	\$ 5.50			37
118											
119	Total E1 - Option 1	37,920 MWh					27,564				29,676
120	Increase/Decrease (\$)										2,112

Line No.	(a) Description	(b) Billing Determinants		(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
				Present				Proposed			
		Quantity	Units	<u>Rate</u> <u>(\$/luminaire/</u> <u>month)</u>	<u>Non-Capacity</u> <u>Energy</u> <u>(\$/kWh)</u>	<u>Capacity</u> <u>Energy</u> <u>(\$/kWh)</u>	<u>Revenue</u> <u>(\$000)</u>	<u>Rate</u> <u>(\$/luminaire/</u> <u>month)</u>	<u>Non-Capacity</u> <u>Energy</u> <u>(\$/kWh)</u>	<u>Capacity</u> <u>Energy</u> <u>(\$/kWh)</u>	<u>Revenue</u> <u>(\$000)</u>
	Co. Owned Ornamental										
1	Mercury Vapor										
2	100 W	10	Lamps	32.48	4.46	0.00	4	32.40	4.66	0.00	4
3	175 W	830	Lamps	37.64	4.46	0.00	406	38.14	4.66	0.00	413
4	250 W	1	Lamps	45.55	4.46	0.00	1	46.51	4.66	0.00	1
5	400 W	418	Lamps	57.87	4.46	0.00	324	59.67	4.66	0.00	335
6	1,000 W	0	Lamps	118.04	4.46	0.00	0	123.26	4.66	0.00	0
7											
8	High Pressure Sodium Vapor										
9	70 W	73	Lamps	24.77	4.46	0.00	23	24.70	4.66	0.00	23
10	100 W	17,584	Lamps	28.06	4.46	0.00	6,351	27.98	4.66	0.00	6,354
11	150 W	445	Lamps	31.04	4.46	0.00	182	31.75	4.66	0.00	186
12	250 W	2,931	Lamps	38.42	4.46	0.00	1,513	39.84	4.66	0.00	1,571
13	360 W	0	Lamps	46.06	4.46	0.00	0	48.40	4.66	0.00	0
14	400 W	961	Lamps	48.83	4.46	0.00	644	51.51	4.66	0.00	679
15	1,000 W	2	Lamps	92.93	4.46	0.00	3	102.41	4.66	0.00	3
16											
17	Metal Halide										
18	70 W	195	Lamps	34.36	4.46	0.00	83	34.30	4.66	0.00	83
19	100 W	83	Lamps	36.37	4.46	0.00	38	36.29	4.66	0.00	38
20	150 W	14	Lamps	40.05	4.46	0.00	7	43.92	4.66	0.00	8
21	175 W	217	Lamps	40.52	4.46	0.00	114	40.37	4.66	0.00	114
22	250 W	264	Lamps	48.13	4.46	0.00	167	48.48	4.66	0.00	169
23	320 W	0	Lamps	53.97	4.46	0.00	0	55.79	4.66	0.00	0
24	400 W	228	Lamps	60.63	4.46	0.00	185	64.15	4.66	0.00	195
25	1,000 W	0	Lamps	110.60	4.46	0.00	0	126.86	4.66	0.00	0
26											
27	De-Energized										
28	Mercury Vapor	0									
29	100 W	0	Lamps	20.61	4.46	0.00	0	20.58	4.66	0.00	0.000
30	175 W	0	Lamps	24.55	4.46	0.00	0	24.87	4.66	0.00	0.000
31	250 W	0	Lamps	30.14	4.46	0.00	0	30.75	4.66	0.00	0.000
32	400 W	0	Lamps	38.93	4.46	0.00	0	40.07	4.66	0.00	0.000
33	1,000 W	0	Lamps	80.75	4.46	0.00	0	84.00	4.66	0.00	0.000
34											
35	LED										
36	60 - 69 W	27	Lamps	14.66	4.46	0.00	5	14.68	4.66	0.00	4.758
37											
38	High Pressure Sodium Vapor										
39	70 W	0	Lamps	15.75	4.46	0.00	0	15.72	4.66	0.00	0.000
40	100 W	0	Lamps	18.10	4.46	0.00	0	18.07	4.66	0.00	0.000
41	150 W	0	Lamps	20.49	4.46	0.00	0	20.95	4.66	0.00	0.000
42	250 W	17	Lamps	25.90	4.46	0.00	5	26.80	4.66	0.00	5.467
43	360 W	0	Lamps	31.55	4.46	0.00	0	33.00	4.66	0.00	0.000
44	400 W	0	Lamps	33.65	4.46	0.00	0	35.31	4.66	0.00	0.000
45	1,000 W	0	Lamps	66.05	4.46	0.00	0	71.87	4.66	0.00	0.000
46											
47	Dusk-Midnight										
48	Mercury Vapor										
49	100 W	0	Lamps	31.42	4.46	0.00	0	31.34	4.66	0.00	0.000
50	175 W	0	Lamps	35.78	4.46	0.00	0	36.28	4.66	0.00	0.000
51	250 W	0	Lamps	42.90	4.46	0.00	0	43.86	4.66	0.00	0.000
52	400 W	0	Lamps	53.63	4.46	0.00	0	55.43	4.66	0.00	0.000
53	1,000 W	0	Lamps	107.44	4.46	0.00	0	112.66	4.66	0.00	0.000
54											
55	High Pressure Sodium Vapor										
56	70 W	0	Lamps	24.03	4.46	0.00	0	23.96	4.66	0.00	0.000
57	100 W	0	Lamps	27.00	4.46	0.00	0	26.92	4.66	0.00	0.000
58	150 W	0	Lamps	29.45	4.46	0.00	0	30.16	4.66	0.00	0.000
59	250 W	0	Lamps	35.77	4.46	0.00	0	37.19	4.66	0.00	0.000
60	360 W	0	Lamps	42.24	4.46	0.00	0	44.58	4.66	0.00	0.000
61	400 W	0	Lamps	44.59	4.46	0.00	0	47.27	4.66	0.00	0.000
62	1,000 W	0	Lamps	82.33	4.46	0.00	0	91.81	4.66	0.00	0.000
	LED										
	130 - 139 W	21	Lamps	27.95	4.46	0.00	7	29.02	4.66	0.00	7.583

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: R. A. Bellini
Page: 54 of 58

Line No.	(a) Description	(b) Billing Determinants		(c) Present	(d)	(e)	(f)	(g) Proposed	(h)	(i)	(j)

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: R. A. Bellini
Page: 55 of 58

Line No.	(a) Description	(b) Billing Determinants		(c)	(d) Present	(e) Non-Capacity Energy	(f) Capacity Energy	(g)	(h) Proposed	(i) Non-Capacity Energy	(j) Capacity Energy	(k) Revenue
		Quantity	Units	Rate (\$/luminaire/mth)	(\$/kWh)	(\$/kWh)	(\$000)	Rate (\$/luminaire/mth)	(\$/kWh)	(\$/kWh)	(\$000)	(\$000)
	Municipally Owned											
1	Mercury Vapor											
2	175 W	0	Lamps	7.86	4.46	0.00	0	9.94	4.66	0.00	0	0
3	250 W	0	Lamps	11.23	4.46	0.00	0	14.20	4.66	0.00	0	0
4	400 W	34	Lamps	17.97	4.46	0.00	10	22.72	4.66	0.00	12	12
5	1,000 W	0	Lamps	44.93	4.46	0.00	0	56.81	4.66	0.00	0	0
6												
7	High Pressure Sodium Vapor											
8	70 W	0	Lamps	5.36	4.46	0.00	0	6.96	4.66	0.00	0	0
9	100 W	0	Lamps	6.56	4.46	0.00	0	8.46	4.66	0.00	0	0
10	250 W	65	Lamps	12.55	4.46	0.00	14	15.94	4.66	0.00	16	16
11	360 W	0	Lamps	16.94	4.46	0.00	0	21.43	4.66	0.00	0	0
12	400 W	20	Lamps	18.53	4.46	0.00	6	23.42	4.66	0.00	7	7
13	1,000 W	0	Lamps	42.47	4.46	0.00	0	53.35	4.66	0.00	0	0
14												
15	Metal Halide											
16	70 W	0	Lamps	0.00	4.46	0.00	0	0.00	0.00	0.00	0.00	0.00
17	100 W	0	Lamps	0.00	4.46	0.00	0	0.00	0.00	0.00	0.00	0.00
18	175 W	0	Lamps	0.00	4.46	0.00	0	0.00	0.00	0.00	0.00	0.00
19	250 W	0	Lamps	0.00	4.46	0.00	0	0.00	0.00	0.00	0.00	0.00
20	400 W	0	Lamps	0.00	4.46	0.00	0	0.00	0.00	0.00	0.00	0.00
21	1,000 W	0	Lamps	0.00	4.46	0.00	0	0.00	0.00	0.00	0.00	0.00
22												
23	De-Energized											
24	Mercury Vapor											
25	175 W	0	Lamps	6.68	4.46	0.00	0	8.02	4.66	0.00	0.00	0.00
26	250 W	0	Lamps	9.55	4.46	0.00	0	11.46	4.66	0.00	0.00	0.00
27	400 W	0	Lamps	14.99	4.46	0.00	0	18.04	4.66	0.00	0.00	0.00
28	1,000 W	0	Lamps	36.88	4.46	0.00	0	44.47	4.66	0.00	0.00	0.00
29		0										
30	High Pressure Sodium Vapor	0										
31	70 W	0	Lamps	4.11	4.46	0.00	0	5.11	4.66	0.00	0.00	0.00
32	100 W	0	Lamps	5.20	4.46	0.00	0	6.40	4.66	0.00	0.00	0.00
33	250 W	0	Lamps	10.38	4.46	0.00	0	12.55	4.66	0.00	0.00	0.00
34	360 W	0	Lamps	14.07	4.46	0.00	0	16.95	4.66	0.00	0.00	0.00
35	400 W	0	Lamps	15.47	4.46	0.00	0	18.61	4.66	0.00	0.00	0.00
36	1,000 W	0	Lamps	35.78	4.46	0.00	0	42.79	4.66	0.00	0.00	0.00
37												
38	Dusk-Midnight											
39	Mercury Vapor											
40	175 W	0	Lamps	6.01	4.46	0.00	0	8.09	4.66	0.00	0.00	0.00
41	250 W	0	Lamps	8.58	4.46	0.00	0	11.55	4.66	0.00	0.00	0.00
42	400 W	0	Lamps	13.73	4.46	0.00	0	18.48	4.66	0.00	0.00	0.00
43	1,000 W	0	Lamps	34.33	4.46	0.00	0	46.21	4.66	0.00	0.00	0.00
44												
45	High Pressure Sodium Vapor											
46	70 W	0	Lamps	4.62	4.46	0.00	0	6.22	4.66	0.00	0.00	0.00
47	100 W	0	Lamps	5.50	4.46	0.00	0	7.40	4.66	0.00	0.00	0.00
48	250 W	0	Lamps	9.90	4.46	0.00	0	13.29	4.66	0.00	0.00	0.00
49	360 W	0	Lamps	13.12	4.46	0.00	0	17.61	4.66	0.00	0.00	0.00
50	400 W	0	Lamps	14.29	4.46	0.00	0	19.18	4.66	0.00	0.00	0.00
51	1,000 W	0	Lamps	31.87	4.46	0.00	0	42.75	4.66	0.00	0.00	0.00
52	Subtotal	119	Lamps				29.89					36.03
53												
54	PSCR	187	MWh	0			0	\$ -				0
55	Subtotal	119	Lamps									36
56	IRM	187	MWh	0.005140			1	0.005140				1
57	Nuclear Decommissioning	187	MWh	0.000882			0.16	0.000882				0.16
58	Subtotal	119	Lamps				31.01					37.15
59												
60	Energy Optimization	18	Meters	\$ 5.50			1.19	\$ 5.50				1.19
61												
62	Total E1 - Option II	187	MWh				32					38
63	Increase/Decrease (\$)											

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: R. A. Bellini
Page: 56 of 58

Case No.: U-21534
Exhibit: A-16
Schedule: F3 Revised
Witness: R. A. Bellini
Page: 56 of 58

Line No.	(a) Description	(b) Billing Determinants	(c)	(d) Present	(e)	(f)	(g)	(h) Proposed	(i)	(j)	
				Non-Capacity		Capacity		Non-Capacity		Capacity	
				Dist Energy	Energy	Energy	Revenue	Dist Energy	Energy	Energy	Revenue
		Quantity	Load (kW)	(¢/kWh)	(¢/kWh)	(¢/kWh)	(\$000)	(¢/kWh)	(¢/kWh)	(¢/kWh)	(\$000)
56	Energy Only Service										
56	LED										
57	280 - 289 W	13	4	10.88	4.46	0.00	2	13.36	4.66	0.00	3
58	290 - 299 W	0	0	10.88	4.46	0.00	0	13.36	4.66	0.00	0
59	300 - 309 W	5	2	10.88	4.46	0.00	1	13.36	4.66	0.00	1
60	310 - 319 W	0	0	10.88	4.46	0.00	0	13.36	4.66	0.00	0
61	320 - 329 W	0	0	10.88	4.46	0.00	0	13.36	4.66	0.00	0
62	330 - 339 W	0	0	10.88	4.46	0.00	0	13.36	4.66	0.00	0
63	340 - 349 W	0	0	10.88	4.46	0.00	0	13.36	4.66	0.00	0
64	350 - 359 W	0	0	10.88	4.46	0.00	0	13.36	4.66	0.00	0
65	360 - 369 W	0	0	10.88	4.46	0.00	0	13.36	4.66	0.00	0
66	370 - 379 W	0	0	10.88	4.46	0.00	0	13.36	4.66	0.00	0
67	380 - 389 W	0	0	10.88	4.46	0.00	0	13.36	4.66	0.00	0
68	390 - 399 W	0	0	10.88	4.46	0.00	0	13.36	4.66	0.00	0
69	LED Subtotal	69,545	8,275				5,331				6,264
70											
71	PSCR	44,120	MWh	0			0	\$ -			0
72	Subtotal	82,402					6,768				7,952
73	IRM	44,120	MWh	0.005140			227	0.005140			227
74	Nuclear Decommissioning	44,120	MWh	0.000882			39	0.000882			39
75	Subtotal	44,120	MWh				7,034				8,218
76											
77	Energy Optimization	40	Meters	\$ 5.50			2.65	\$ 5.50			2.65
78											
79	Total E1 - Option III	44,120	MWh				7,036				8,221
80	Increase/Decrease (\$)										1,185
	Total E1 - Options I, II and III	123,056	MWh				63,859				67,751

Michigan Public Service Commission
DTE Electric Company
Present and Proposed Revenue
EV Fast Charger General Service Rate
FOR DISCUSSION ONLY

Case No.: U-21534
Exhibit: A-16
Schedule: F9 Revised
Witness: A. Willis
Page: 1 of 1
Revised

Line	(a)	(b)	(c)	(d)
No.	Description	Billing Determinants Revised	Proposed Revised	
	Full Service Power Supply	<u>Quantity</u> <u>Units</u>	<u>Rate</u> <u>Revenue</u> (\$000)	
1	Capacity			
2	June - September			
3	On Peak (1pm - 5pm M-F)	753 MWh	\$0.04204	32
4	Off Peak	3,711 MWh	\$0.02508	93
5	October - May			
6	On Peak (1pm - 5pm M-F)	1,372 MWh	\$0.02683	37
7	Off Peak	6,924 MWh	\$0.02508	174
8				
9	Non-Capacity			
10	June - September			
11	On Peak (1pm - 5pm M-F)	753 MWh	\$0.10939	82
12	Off Peak	3,711 MWh	\$0.06524	242
13	October - May			
14	On Peak (1pm - 5pm M-F)	1,372 MWh	\$0.06981	96
15	Off Peak	6,924 MWh	\$0.06524	452
16				
17	PSCR	12,761 MWh	\$0	0
18	REPS	21 Meters	\$0	0
19	Total Full Service Power Supply	12,761 MWh	9.46¢	1,207
20				
21	Full Service Distribution	<u>Quantity</u> <u>Units</u>		
22				
23	Service Charge	21 Cust.	\$11.25	3
24				
25	Distribution Charge	12,761 MWh	\$0.11896	1,518
26	Distribution System	12,761 MWh	11.92¢	1,521
27	IRM	12,761 MWh	\$0.000595	8
28	Nuclear Decomm.	12,761 MWh	\$0.000882	11
29	Energy Optimization	21 Meters	\$5.50	1
30	LIEAF	21 Meters	\$0.88	0
31	Distribution Surcharges	12,761 MWh	0.16¢	20
32				
33	Total Full Service Distribution	12,761 MWh	12.08¢	1,541
34	Total Full Service	12,761 MWh	21.54¢	2,749

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

MICHAEL J. HATSIOS

DTE ELECTRIC COMPANY
QUALIFICATIONS AND REVISED DIRECT TESTIMONY OF MICHAEL J.
HATSIOS

Line
No.

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

2 A1. My name is Michael J. Hatsios (he/him/his), and my business address is One
3 Energy Plaza, Detroit, Michigan, 48226. I am employed as Director - Customer
4 Service Operations by DTE Energy Corporate Services, LLC, a subsidiary of DTE
5 Energy.

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

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

10

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

12 A3. I earned a bachelor's degree in mechanical engineering from Lawrence
13 Technological University in Southfield, MI, and a master's degree in business
14 administration from the University of Michigan's Ross School of Business, Ann
15 Arbor, MI.

16

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

18 A4. Prior to joining DTE, I was employed in various roles as a design and
19 manufacturing engineer for Ford Motor Company and Visteon Automotive. I
20 joined DTE in 2001, and since then I have held positions of increasing
21 responsibility in our non-regulated subsidiaries, Treasury, the Controller's Office,
22 Fossil Generation, Enterprise Performance Management (EPM), and Customer
23 Service.

24

Line
No.

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

2 A5. Currently, I am a Director in the Customer Service organization, where I serve as
3 the Chief of Staff for the Senior Vice President of Customer Service. In this role,
4 I am responsible for the Annual Planning Cycle (APC), Customer Research, Data
5 Analytics, and the Customer Service IT Capital, and Customer Service O&M,
6 portions of DTE Electric and DTE Gas rate case filings.

7
8 **Q6. Have you previously sponsored testimony before the Michigan Public Service**
9 **Commission (MPSC or Commission)?**

10 A6. Yes. I have sponsored testimony in the following case:

11 U-21087 Voluntary PrePay Billing Program

12 U-21297 DTE Electric Company 2023 General Rate Case

13 U-21291 DTE Gas Company 2024 General Rate Case

14

15 **Part 1. Purpose of Testimony**

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

17 A7. The purpose of my testimony is to:

18

19 • Describe and support the Company's Customer Service IT Portfolio and capital
20 investment in the following IT Investment Categories: Regulatory/Compliance,
21 IT Enhancements, and Strategic.

22 • Support the reasonableness and prudence of capital expenditures for applicable
23 projects within DTE Electric's Customer Service IT Portfolio in the amount of
24 \$62.1 million for the historical test year ended December 31, 2022, \$74.6
25 million in the bridge period (for the 24 months ending December 31, 2024), and

Line
No.

- 1 \$33.0 million for the projected test year period ending December 31, 2025. My
2 testimony describes, among other things, how these projects improve
3 operational efficiencies, reduce operating costs, enhance customer interactions,
4 increase customer access to information, satisfy regulatory and compliance
5 requirements, and create opportunities for more customers to voluntarily
6 participate in the expansion of the Company's renewable energy portfolio.
- 7 • Provide details supporting the Company's request for cost recovery of \$11.4
8 million in historical capital investments related to digital self-service projects
9 and a portion of the Advanced Analytics Use Case project that were approved
10 in Case No. U-20836 but subsequently disallowed in Case No. U-21297,
11 consisting of \$5.7 million in 2021 and \$5.7 million in 2022-2023.
- 12 • Provide details supporting the capital that is being sought for the Company's
13 Error Free Communication – Outage Status initiative shown in Exhibit A-12,
14 Schedule B5.4 Distribution Plant – Technology and Automation page 18, Lines
15 33 and 40 for 2022-2023 investments and Line 33 for 2024-2025 investments,
16 in the amount of \$8.4 million for the historical test year ended December 31,
17 2022, \$5.2 million in the 2023-2024 bridge period (for the 24 months ending
18 December 31, 2024), and \$0.6 million for the projected 2025 test year period
19 ending December 31, 2025.
- 20 • Discuss the variance of actual 2022 capital spend compared to 2022 capital
21 spend approved in Case No. U-21297. Additionally, provide explanation for
22 projected budget differences in 2023 and 2024 (as compared to U-21297) for
23 projects that meet the requirement established in the U-20162 final order.
- 24 • Provide details of the Company's actual \$112.4 million Customer Service
25 Operation and Maintenance (O&M) expenses for the twelve-month period that

Line
No.

1 ended December 31, 2022, and support the Company's projected \$118.6
2 million Customer Service O&M expenses for the projected test year period
3 ending December 31, 2025.

4

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

6 A8. Yes. I am sponsoring the following exhibits:

7

8	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
9	A-12	B5.7.3	IT Customer Service Capital Expenditures
10	A-13	C5.7	Projected Operation and Maintenance Expenses –
11			Customer Service
12	A-13	C5.9.2	ACPP and TOD Regulatory Asset Deferrals
13	A-24	N1.1	Customer Service IT Business Cases - Executive
14			Summaries
15	A-24	N2	Historical Spend Variance Summary
16	A-24	N3.1	Customer IT Capital Investments with Additional
17			Project Details
18	A-24	N5	Call Volume Reduction Savings Summary
19	A-24	N6	NPV Model for Digital Self-Service Projects
20	A-24	N7	Error Free Communication (EFC) Capital Spend
21	A-24	N8	IT Capital Approved in Case No. U-20836
22	A-24	N9	Operational Efficiencies Summary
23	A-24	N10	2022-2024 Outage and EFC Channel Enhancements

24

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

Line
No.

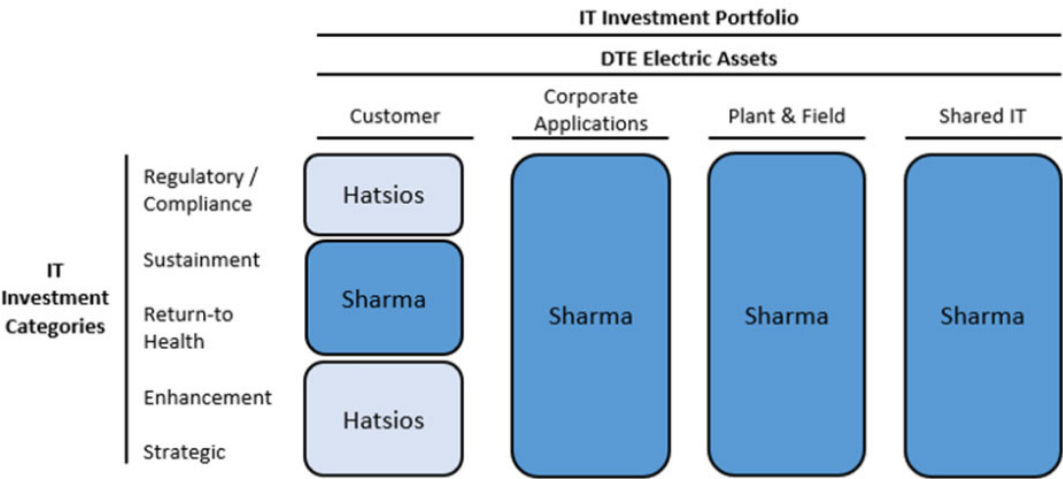
1 A9. Yes, they were. I co-sponsor Exhibit A-24, Schedule N2, with Company Witness
2 Sharma and Exhibit A-13, Schedule C5.9.2 with Company Witness Bennett.

3
4 **Part 2. Customer Service IT Portfolio Overview**

5 **Q10. How do the projects in the Customer Service IT Portfolio align with the**
6 **Company’s overall IT Investment Portfolio?**

7 A10. The Customer IT Portfolio is a subset of DTE’s IT Investment Portfolio and has
8 been developed in parallel with the DTE IT 5-year plan (2021-2025) filed in Case
9 No. U-20561. A view of the structure of the DTE IT Investment Portfolio, the
10 associated IT Investment Categories, and the responsible witness in the instant case
11 is provided in Figure 1.

12
13 **Figure 1 - DTE IT Investment Portfolios**



14
15 Consistent with the other IT Investment Portfolios, the projects in the Customer
16 Service IT Portfolio have been categorized into five areas of targeted investment –

Line
No.

1 Regulatory/Compliance, Sustainment, Return to Health, IT Enhancements, and
2 Strategic (Figure 2).

3

4

Figure 2 - DTE IT Investment Categories

Non-Discretionary	Regulatory/ Compliance	Required spend due to regulatory requirements
	Sustainment	Required spend to 'run' the organization (e.g., basic internal labor, base operating and system maintenance costs)
	Return-to-Health	Required investments to update systems that are in critical health or have reached end of life
Discretionary	IT Enhancements	Discretionary capacity/capability performance upgrades to core platforms (e.g., SAP, IT) determined by business needs which are not required for 'keeping the lights on'
	Strategic	Strategic spend to unlock a new business capability that can realize value for the organization (e.g., customer satisfaction, increased revenue to offset rate increases, etc.)

5

6 **Q11. Which IT Investment Categories within the Company's Customer Service IT**
7 **Portfolio are addressed in your testimony?**

8 A11. As shown in Figure 1, my testimony includes projects within DTE Electric's
9 Customer Service IT Portfolio in the following IT Investment Categories:
10 Regulatory and Compliance, IT Enhancements, and Strategic. As noted in Figure
11 2, the capital projects addressed in my testimony relate directly to those non-
12 discretionary and discretionary projects that either are required by mandate or
13 compliance rules (Regulatory and Compliance), or directly target enhancing the
14 customer experience, reducing operational costs, and improving the effectiveness
15 with which we serve customers (IT Enhancements and Strategic).

16

Line
No.

1 Not included in my testimony are those Customer Service IT Portfolio projects that
2 are included in the Sustainment and Return-to-Health IT Investment Categories.
3 These are included in Exhibit A-12, Schedule B5.7.2 and discussed in Company
4 Witness Sharma's testimony.

5

6 **Part 3. Company Witness Hatsios Sponsored Projects – Overview**

7 **Q12. Please confirm DTE Electric's Customer Service capital investments in each**
8 **of the three IT Investment Categories (e.g., Regulatory/Compliance, IT**
9 **Enhancements, Strategic).**

10 A12. As reflected in Exhibit A-12 Schedule B5.7.3, DTE Electric will invest the below
11 amounts in the three IT Investment Categories covered in my testimony:

12

13 • Regulatory and Compliance – the Company will invest \$59.9 million in the
14 Regulatory and Compliance category over the course of 48-months ending
15 December 31, 2025, consisting of \$21.1 million in the historical period, \$21.3
16 million in the 2023-2024 bridge period, and \$17.5 million in the 2025 test
17 period, as shown in Lines 1 through 17 of the Capital Expenditures Exhibit A-
18 12 Schedule B5.7.3.

19 • IT Enhancements – the Company will invest \$18.8 million in the IT
20 Enhancements category over the course of 48-months ending December 31,
21 2025, consisting of \$7.4 million in the historical period, \$4.2 million in the
22 2023-2024 bridge period, and \$7.2 million in the 2025 test period, as shown in
23 Lines 18 through 26 of the Capital Expenditures Exhibit A-12 Schedule B5.7.3.

24 • Strategic – the Company will invest \$90.6 million in the Strategic category over
25 the course of 48-months ending December 31, 2025, consisting of \$33.2 million

Line
No.

1 in the historical period, \$49.0 million in the 2023-2024 bridge period, and \$8.4
2 million in the 2025 test period, as shown in Lines 27 through 47 of the Capital
3 Expenditures Exhibit A-12 Schedule B5.7.3.

4

5 **Q13. How do the Customer Service Regulatory and Compliance, IT Enhancements,**
6 **and Strategic capital projects in your testimony align with the Company's**
7 **priorities?**

8 A13. The Company is committed to providing reliable, safe, and affordable utility service
9 to its customers, expanding its renewable energy portfolio, and reducing its carbon
10 footprint. DTE's Customer Service organization is aligned with and supports these
11 priorities, and is committed to cost effectively providing customers with engaging
12 and satisfying transactional (e.g., orders) and non-transactional (e.g., inquiries)
13 interactions across its service channels, which includes enrolling customers in the
14 Company's voluntary clean energy products and services.

15

16 To that end, the Regulatory, IT Enhancement, and Strategic capital projects
17 supported in my testimony are intended to deliver the following outcomes and
18 customer benefits:

19

20 1. Effective and Affordable Digital Self-Service Solutions – Provide customers
21 with satisfying and seamless digital self-service alternatives to having to call
22 the Contact Center, which makes it easier for customers to complete their
23 interactions, improve service levels, and reduce operating expenses, with
24 resultant savings passed on to customers through the ratemaking process.

Line
No.

1 2. Increased Operational Efficiencies – Create efficiencies across the Customer
2 Service operating groups to improve the efficiency and productivity of our
3 operations and projects, or to reduce the cost of operations, with resultant
4 savings passed on to customers through the ratemaking process.

5 3. Enhanced Customer Interactions – Improve the effectiveness and quality with
6 which the Company interacts and communicates with customers, ensuring
7 customers receive timely, accurate, and consistent information.

8 4. Enhanced and Expanded Clean Energy Products – Provide customers with
9 voluntary programs and services that promote and support their carbon
10 reduction goals and the growth of the Company’s renewable energy assets.

11

12 **Q14. Please specify how capital projects are consolidated and presented in your**
13 **testimony to align with the above-referenced outcomes and customer benefits.**

14 A14. I have consolidated the projects for which I am providing testimony in a manner
15 that aligns the individual projects with the outcomes and customer benefits
16 described in my response to Q13. As such, the remainder of the capital IT portion
17 of my testimony is organized as shown below.

18

19 Part 4 – Digital Self-Service Projects

20 Part 5 – Operational Efficiency Projects

21 Part 6 – Projects that Enhance Customer Interactions

22 Part 7 – Regulatory, Compliance, and Clean Energy Projects

23 Part 8 – 2022 Historical Capital Project Variance

24

Line
No.

1 **Q15. Are there any IT projects shown in Exhibit A-12 Schedule B5.7.3 that have**
2 **already been approved for cost recovery in a prior rate case and for which the**
3 **Company is not providing additional supporting testimony in the instant case?**

4 A15. Yes. The projects in Table 1 below, which were supported in my testimony in Case
5 No. U-21297, and which were approved for cost recovery by the Commission in
6 their final order in that case, will not be further discussed in my testimony in the
7 instant case.

8

9

Table 1. Capital Projects Approved in U-21297

Project Name	Portfolio	Category	U-21534 Exhibit Reference	U-21297 Exhibit Reference
ACPP/Time of Day	Customer	Regulatory/Compliance	Line 1, A-12 B5.7.3	Line 1, A-12 B5.7.3
Corporate Energy Forecasting	Customer	Regulatory/Compliance	Line 2, A-12 B5.7.3	Line 2, A-12 B5.7.3
MIGP - Fixed Price Product(Rider17)	Customer	Regulatory/Compliance	Line 5, A-12 B5.7.3	Line 3, A-12 B5.7.3
MIGP Section 61 Settlement	Customer	Regulatory/Compliance	Line 9, A-12 B5.7.3	Line 6, A-12 B5.7.3
Payment Stability Plan	Customer	Regulatory/Compliance	Line 13, A-12 B5.7.3	Line 8, A-12 B5.7.3
Treasury Credential on File	Customer	Regulatory/Compliance	Line 17, A-12 B5.7.3	Line 13, A-12 B5.7.3
Customer Legacy Applications Enhancement	Customer	IT Enhancements	Line 20, A-12 B5.7.3	Line 15, A-12 B5.7.3
Customer Service Communications	Customer	Strategic	Line 32, A-12 B5.7.3	Line 33, A-12 B5.7.3
Enhanced Training Environments	Customer	Strategic	Line 34, A-12 B5.7.3	Line 35, A-12 B5.7.3
Field Service Management Billing & Metering	Customer	Strategic	Line 37, A-12 B5.7.3	Line 40, A-12 B5.7.3
Field Service Management for RM&P	Customer	Strategic	Line 36, A-12 B5.7.3	Line 39, A-12 B5.7.3
Platform Integration Component	Customer	Strategic	Line 43, A-12 B5.7.3	Line 50, A-12 B5.7.3
Qualtrics Expansion	Customer	Strategic	Line 44, A-12 B5.7.3	Line 53, A-12 B5.7.3
Speech Analytics	Customer	Strategic	Line 46, A-12 B5.7.3	Line 57, A-12 B5.7.3
Workforce Automation for Contact Center	Customer	Strategic	Line 47, A-12 B5.7.3	Line 58, A-12 B5.7.3

10

11 **Q16. Are you providing any additional project details for the projects in Exhibit A-**
12 **12, Schedule B5.7.3?**

Line
No.

1 A16. Yes. I am providing in Exhibit A-24, Schedule N1.1 business case executive
2 summaries for all the projects, and project capital, included in Exhibit A-12,
3 Schedule B5.7.3. Exhibit A-24 Schedule N3.1 also provides a greater level of detail
4 in the format requested by Commission Staff, as set forth in new filing requirements
5 adopted in the Commission's May 18, 2023 Order in Case No. U-18238.

6

7 **Part 4. Digital Self-Service Projects**

8 **Q17. Can you explain why the Company is investing capital in its Digital Self-**
9 **Service solutions?**

10 A17. Yes. The Company is investing capital in its digital self-service solutions to provide
11 customers with seamless and satisfying self-service alternatives to having to call
12 the Contact Center, both to meet the demands of those customers who prefer to
13 engage with the Company in a self-service channel, and to reduce the volume of
14 live calls handled by DTE's CRs.

15

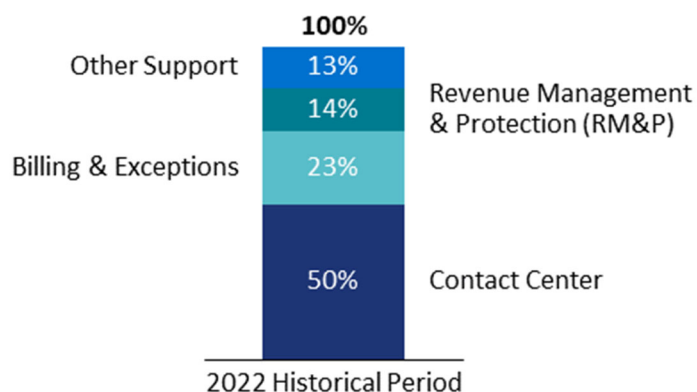
16 **Q18. What is the Company's motivation to reduce the volume of calls handled by**
17 **CRs in its Contact Center?**

18 A18. The cost of Contact Center operations represents the largest portion of the total
19 Customer Service (CS) Operating & Maintenance (O&M) expense, as shown in
20 Figure 3, which reflects the percent of the total CS O&M expense incurred by each
21 of the CS operating groups during the 2022 historical period – as provided in
22 Exhibit A-13, Schedule C5.7, Line 5, Column G.

23

Line
No.

1

Figure 3 - CS O&M Expense (% of spend by group)

2

3 In the 2022 historical period, the Contact Center contributed 50% of the total CS
 4 O&M expense, with the most significant driver of Contact Center costs being the
 5 handling of live phone calls by CRs. In fact, each incremental call handled by a
 6 CR in the Contact Center costs the Company \$11.34, which reflects the 2022
 7 weighted average cost of the Company's internal and external CR resources, and
 8 includes overhead costs (e.g., benefits, payroll taxes, etc.) for the internal DTE CRs.

9

10 **Q19. How do customers benefit from the reduction in call volumes?**

11 A19. CRs continue to handle millions of live calls from customers every year, which at
 12 \$11.34/call results in tens of millions of dollars in DTE Contact Center O&M
 13 expense, which is passed on to customers through the utility ratemaking process.
 14 As such, reducing calls represents a significant opportunity for the Company to
 15 reduce its operating costs and the associated O&M expense that is passed on to
 16 customers.

17

Line
No.

1 Additionally, with fewer live calls to handle, the Company can sustain its desired
2 service levels (e.g., average speed of answer, call abandon rates), and CRs will have
3 the capacity to more effectively handle those more complex inquiries from
4 customers that may not be as effectively handled in a digital self-service solution
5 (e.g., low-income self-sufficiency program – LSP and payment stability plan – PSP
6 enrollments).

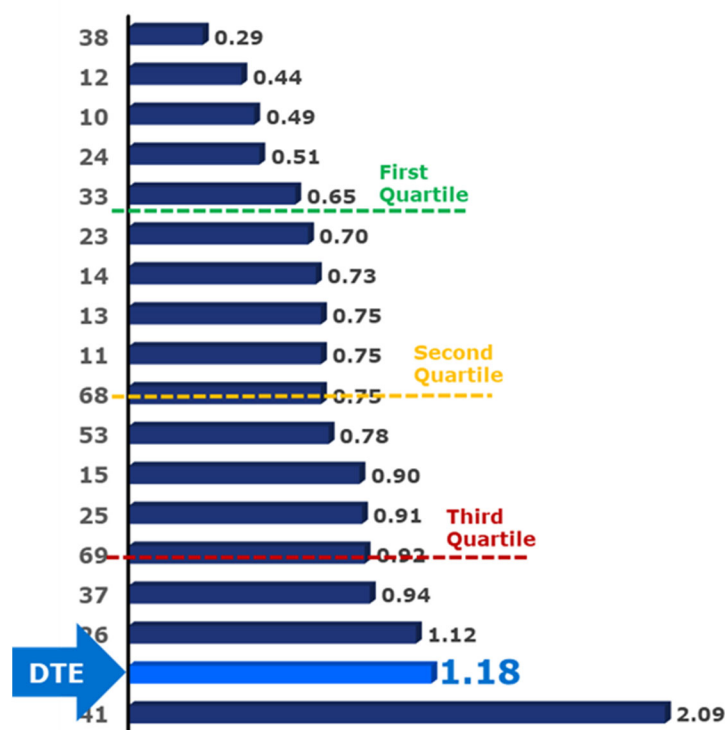
7

8 **Q20. How does the Company's volume of calls compare to its peers?**

9 A20. The Company continues to lag its utility peers in the volume of calls it handles per
10 customer, as reflected in the most recent 2023 First Quartile Consulting
11 Benchmarking Study (Figure 4).

12

13 **Figure 4 - 2023 First Quartile Live Calls per Customers**



Line
No.

1

2

The above study reflects full-year 2022 data as submitted by each of the participating utilities, with DTE currently at the bottom of the 4th quartile, indicating that there remains significant opportunity for DTE to reduce calls, and the associated costs of handling those calls.

6

7

Q21. What are the most common reasons why customers call the Company?

8

A21. The Company has identified the types of transactional (e.g., orders) and non-transactional (e.g., inquiries) interactions with customers that drive the majority of its total call volume, which I have summarized below.

10

11

12

1. Collection – Calls from customers who received a shutoff notice, or have been disconnected for nonpayment, and are contacting the Company to discuss the options available to them to avoid shutoff or to restore service. Many of these calls are from the Company’s most vulnerable, low-income customers who are calling about available energy assistance and to discuss payment plan options.

13

14

15

16

17

2. Billing – Calls from customers who want to verify their account balance, have questions about their bill, or want to enroll in one of the Company’s billing programs (e.g., Budget Wise Billing, ebill).

18

19

20

3. Move-In/Move-Out (MIMO) – Calls from existing and new customers requesting to Start Service at a new location, Stop Service at an existing location, Transfer Service between locations, or inquiry about or change to an existing MIMO service order.

21

22

23

24

4. Payments – Calls from customers who want to pay their monthly bill or to check on the status of a recent payment.

25

Line
No.

1 5. Outage – Calls from customers who are reporting an electric outage or checking
2 on the status of a reported electric outage.

3

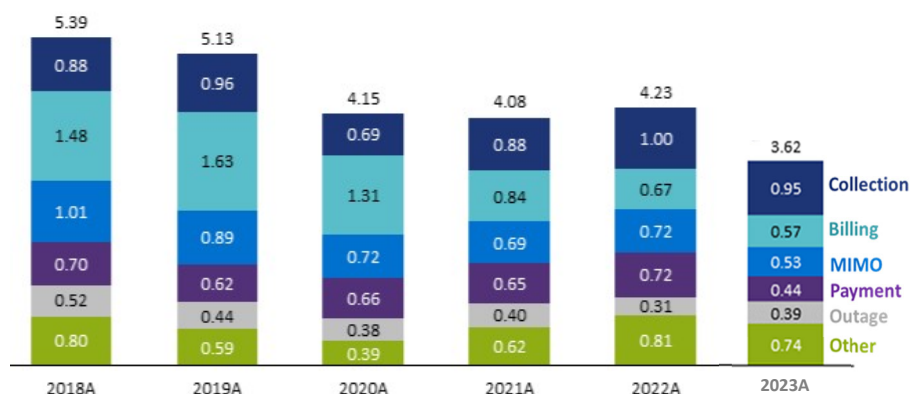
4 **Q22. How has the total volume of calls been trending in the past five years?**

5 A22. The Company has seen a reduction of 1.77 million calls from 2018-2023, with
6 approximately one-third of that reduction coming in 2023 (Figure 5).

7

8

Figure 5 - Call Volumes by Type (millions)



9

10 The call volumes reflected in Figure 5 include the total volume of calls received
11 from both DTE Electric and DTE Gas customers. For the remainder of my
12 testimony, unless otherwise stated, the outcomes and customer benefits associated
13 with each of the capital projects for which I am providing testimony, can be
14 assumed to be shared between DTE Electric and DTE Gas customers.

15

16 **Q23. How have the Company's historical investments in its digital self-service**
17 **solutions contributed to the reduction in calls since 2018?**

Line
No.

1 A23. The Company has been able to enhance and expand its digital self-service solutions
2 in a manner that provides customers with increased and effective self-service
3 alternatives to calling the Contact Center. Over time, as these digital solutions grew
4 and matured, customers increasingly chose to engage in the use of these solutions
5 in lieu of calling the Contact Center.

6

7 For example, in 2018, customers could view and pay their bill online, report and
8 check on the status of outages on the Web and in the Mobile App, and use the Web
9 to complete their MIMO transaction. Today, customers can do all those things and
10 more, including, but not limited to, interacting with the Company via social media
11 and Web chat, processing Collection restores on the Web and in the Interactive
12 Voice Response (IVR) system, enrolling in a payment extension in the IVR through
13 a Virtual Assistant (VA) and on the Web, self-analyzing their bills online and in
14 the IVR through a VA, processing MIMO requests in the IVR through a VA, and
15 tracking the status of their MIMO and Collection requests using the Company's
16 online order trackers.

17

18 **Q24. How does the Company measure the level of customer engagement in the use**
19 **of its digital self-service solutions?**

20 A24. The Company has established a "Digital Engagement Rate" (DER) metric for each
21 of the five categories of customer interactions – Collection, MIMO, Billing,
22 Payment, and Outage – to measure and track the engagement of its customers in
23 the digital self-service solutions.

24

Line
No.

1 For each of the identified five customer interactions, the Company measures the
2 percent of customers who complete a transactional interaction in a digital self-
3 service channel, relative to the total number of completed served and self-served
4 transactional interactions – e.g., if customers complete a total of 20,000 total MIMO
5 transactions in a week, and 10,000 of those are successfully completed using a
6 digital self-service solution, the MIMO DER for that week would be 50%. With
7 the exception of Billing interactions, for which non-transactional inquiries are
8 included in the DER, non-transactional interactions are excluded from the DER
9 calculation for the other customer interactions. Going forward, I will use the term
10 transaction when discussing the DER for each category of customer interactions.

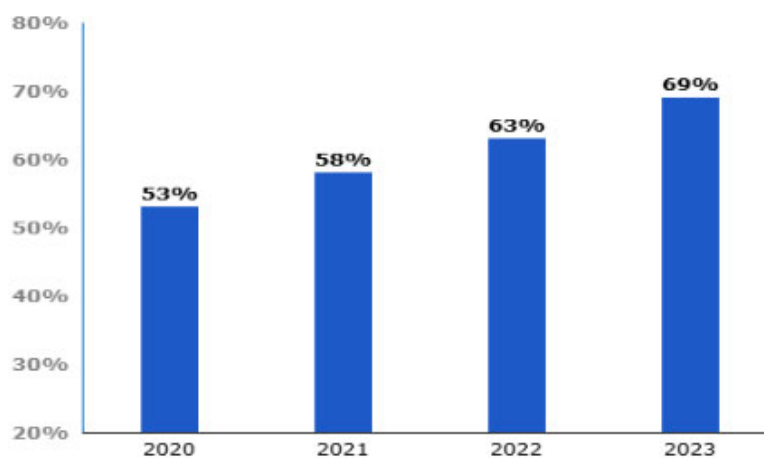
11

12 **Q25. How has the DER been trending in recent years?**

13 A25. The Company has been tracking the DER for each transaction since 2020, and has
14 seen the overall DER steadily increase from 53% to 69% (Figure 6).

15

16 **Figure 6 - Digital Engagement Rate (2020-2023)**



17

Line
No.

1 **Q26. What factors impact the DER, and how has the DER increased for each of the**
2 **transactions?**

3 A26. The DER for each transaction is a function of the number of customers who choose
4 to use a digital self-service solution, and the number of those customers who are
5 able to successfully complete their interaction in that solution, which the Company
6 refers to as the “Digital Completion Rate” (DCR).

7

8 In other words, to increase the DER for a particular transaction, the digital self-
9 service solutions for that transaction must be seen by customers as an attractive
10 alternative to calling the Contact Center, and it must be designed so that a high
11 percentage of customers who choose to use a digital solution are able to
12 successfully complete their transaction. In general, the more complex the
13 transaction, and the more information customers are asked to provide, the more
14 opportunity there is for customers to “drop-off” and call the Contact Center to
15 complete their transaction. Below is a summary of the DER (Table 2) for each
16 transaction since 2020, along with the Company’s long-term targets.

17

18 **Table 2. Digital Engagement Rate by Transaction**

19

Transaction	2020	2021	2022	2023	Long Term Target
Collection	0%	5%	16%	30%	60%
MIMO	19%	25%	32%	42%	60%
Billing	76%	86%	89%	92%	95%
Outage	91%	93%	94%	96%	98%
Payment	78%	80%	82%	84%	85%
Overall	53%	58%	63%	69%	80%

20

Line
No.

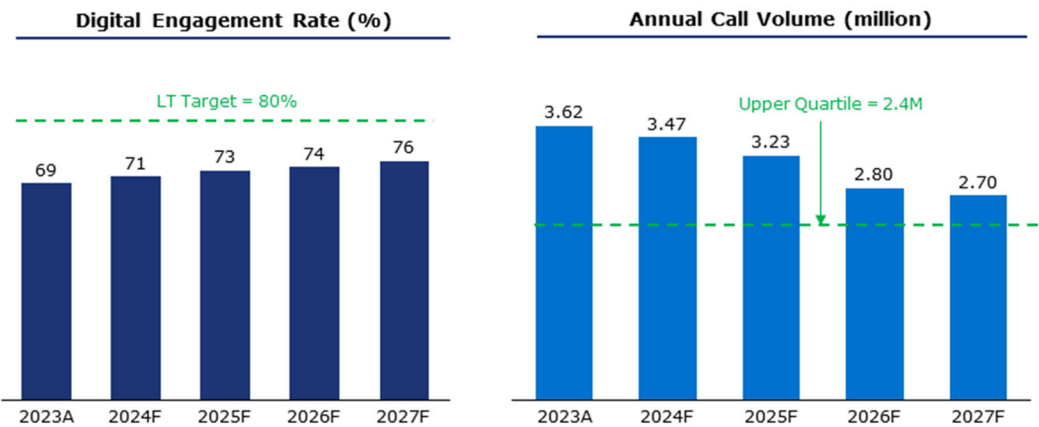
1 These increased DERs are a direct result of the Company’s investment in the
2 expansion of its digital self-service offerings, and its commitment to ensure that
3 customers who choose to engage in the use of these solutions are able to
4 successfully complete their transaction.

5
6 **Q27. What are DER and call volumes that the Company is forecasting to achieve**
7 **through its capital investments in its digital self-service solutions?**

8 A27. The Company is forecasting that its investments in its digital solutions will further
9 increase customer engagement in the digital solutions, increase DER closer to the
10 Company’s long-term target, and reduce call volumes to near upper quartile levels
11 (Figure 7).

12

13 **Figure 7 - Forecasted DER and Call Volumes**



14

15 Detailed summaries of the realized and forecasted DER increases, call volume
16 reductions, and O&M savings can be found in Exhibit A-24, Schedule N5.

17

Line
No.

1 **Q28. What are the total cumulative call volume savings the Company is forecasting**
2 **to achieve through its investments in the digital self-service solutions?**

3 A28. As seen in Exhibit A-24, Schedule N5, Page 1, Column h, Line 16, the Company
4 is forecasting that reducing total call volume to 2.7 million (Figure 7) will provide
5 customers with total cumulative net O&M savings through 2027 of \$15.6 million.

6
7 **Q29. Is the Company removing the forecasted call volume savings from its**
8 **operating budget and its requested O&M recovery in the instant case?**

9 A29. Yes. As it did in U-21297, the Company is removing the annual call volume
10 savings for the projected test year from the Customer Service O&M budgets and
11 from its requested O&M recovery in the instant case, which is discussed in my
12 Customer Service O&M testimony (Part 9) and as reflected in my supporting
13 Exhibit A-13 Schedule C5.7 on Line 5, Column (k) for Customer Records and
14 Collection Expenses, and in footnote 3. This reduction is also highlighted in Exhibit
15 A-24, Schedule N5, Page 1, Column f, Line 17.

16
17 **Q30. Which projects support the enhancement and expansion of the Collection**
18 **digital solutions?**

19 A30. The Company will invest \$10.7 million in five projects to enhance and expand the
20 Collection digital solutions over the course of 48-months ending December 31,
21 2025, consisting of \$2.8 million in the historical period, \$5.9 million in the 2023-
22 2024 bridge period, and \$2.0 million in the 2025 test period, as shown in Exhibit
23 A-12, Schedule B5.7.3, and which I have summarized in Table 3 below. See
24 Exhibit A-24 Schedule N3.1 Lines 13-15, 20-21, 25-26, 41 for additional project
25 details.

Line
No.

Note that \$0.4 million of the total \$2.8 million in 2022 historical spend for the Customer Relationship and Billing (CR&B) Enhancement project was allocated to the digital projects, with \$0.1 million allocated to Collection. \$2.3 million of the \$6.8 million in 2022 historical capital for the Journey Work Product Transformation Teams project was also allocated to Collection digital solutions.

Table 3. Collection Digital Self-Service Capital (\$000s)

Line Item	Project Name	Year	Total Capital	Allocated to Collections
21	CR&B Enhancement	2022	\$2,794	\$100
29	Collection Web Self-Service	2023-25	\$7,880	\$7,880
31	Customer Closed Loop Development	2022	\$314	\$314
39	Journey Work Product Transformation Teams	2022	\$6,744	\$2,300
48	API Integration Security Gateway – API Layer*	2022	\$70	\$70
Total (2022-2025)			\$17,802	\$10,664

* Included in Projects < \$250K

Q31. Can you elaborate on the scope of work that is being funded by the Collection digital self-service capital?

A31. Yes. The capital allocated to the Collection digital self-service solutions is intended to enhance the Company's existing Collection digital solutions, and to expand the number of available digital solutions, as follows – please note in 2022-2023 the four projects in Table 3 incurred \$5.1 million in capital to modify the customer systems as necessary to deliver the highlighted improvements, while in 2024-2025 an additional \$5.5 million in capital will be spent solely by the Collection Web Self-Service project.

Line
No.

1

2

2022-2023 Collection Digital Improvements

3

- Increase Collection DCR and DER by addressing defects and cumbersome process flows in the digital solutions that are preventing customers from successfully completing their digital transaction (2022-2023).

4

5

6

- Provide customers the ability to process a restore of service on the Web (February 2023).

7

8

- Provide customers the ability to enroll in a payment extension hold on the Web (August 2023).

9

10

- Provide customers the ability to check on the status of an account lock on the Web for the status of payment extension holds, medical holds, pending energy assistance funding, and pending income status verifications (October 2023).

11

12

13

14

2024-2025 Collection Digital Improvements

15

- Increasing Collection DCR and DER by addressing defects and cumbersome process flows in the digital solutions that are preventing customers from successfully completing their digital transaction (2024-2025).

16

17

18

- Expanding restore and payment extension eligibility to include more customers (2024-2025).

19

20

- Providing the ability for customers to enroll in a payment arrangement on Web to pay their past due amount over time. (May/June 2024).

21

22

- Providing customers with new online assistance tools that will guide customers who are having difficulty paying their bill to the most appropriate payment solutions, and sources of energy assistance (2024-2025).

23

24

25

Line
No.

1 **Q32. What are the realized and forecasted customer benefits of the identified scope**
2 **of work funded by the Collection digital self-service capital?**

3 A32. In terms of call volume reductions, while 2023 Collection call volumes are not
4 materially different than they were four or five years ago, they have been reduced
5 by 50,000 relative to 2022 (Figure 5). This is despite an 11% increase in the number
6 of active low-income customers versus 2022, a 28% increase in the number of low-
7 income customers who reached final arrears status, a 15% reduction in available
8 Energy Assistance (EA) funding, and an increase in shutoff notices from 1.9 million
9 to 2.1 million.

10

11 Together, these factors would be expected to significantly increase the volume of
12 Collection calls, especially for general inquiries and inquiries related to EA
13 funding. The Company maintains that the expected increase in Collection inquiry
14 calls, was mitigated by a reduction in the number of calls from customers who chose
15 to use a digital solution to restore service, to enroll in a payment agreement, or to
16 check on the status of an account hold.

17

18 Given the results achieved to-date from the Collection digital self-service capital
19 investments, the Company is forecasting that its historical and planned investments
20 in the Collection digital self-service solutions will increase the Collection DER to
21 48% by 2027, will enable a cumulative decrease of 343,600 calls (2023-2027), and
22 will provide customers with a cumulative \$3.9 million in O&M savings (2023-
23 2027). The annual Collection call volumes and associated O&M savings are
24 provided in Exhibit A-24, Schedule N5.

25

Line
No.

1 **Q33. Are there any other benefits, beyond O&M savings, to customers of the**
2 **Company's investments in Collection digital self-service?**

3 A33. Yes. While the Company anticipated that its payment extension VA and Web
4 solutions would provide increased numbers of customers an easy-to-use tool that
5 allows them more time to pay their past due balance, it did not expect such rapid
6 customer adoption of these solutions, nor did it expect the number of payment
7 enrollments to triple, as shown in Table 4.

8

9 **Table 4. Payment Extension Summary**

10

Year	Total Payment Extensions	DER	Paid On-Time
2021	47,400	4%	37%
2022	88,650	40%	39%
2023	144,350	67%	44%

11

12 The data in Table 4 indicates that in 2023, 67% of all payment extension
13 enrollments were completed in a self-service solution, and 44% of the total
14 enrollments were successfully paid within the required 10-day post enrollment
15 period. In other words, 63,500 times (144,350 enrollments times 44% paid on-
16 time), customers were able to leverage the use of a payment extension to pay their
17 past due balance in full and avoid a shutoff of service.

18

19 **Q34. Which projects support the expansion of the MIMO digital transaction?**

20 A34. The Company will invest \$15.8 million in four projects to enhance and expand the
21 MIMO digital self-service solutions over the course of 48-months ending

Line
No.

December 31, 2025, consisting of \$4.4 million in 2022 historical period, \$8.9 million in 2023-2024 bridge period, and \$2.5 million in 2025 test period capital, as shown in Exhibit A-12 Schedule B5.7.3, which I have summarized in Table 5 below. See Exhibit A-24 Schedule N3.1 Lines 25-26, 39-40, 41, 58-60 for additional project details.

Note that \$0.4 million of the total \$2.8 million in 2022 historical spend for the Customer Relationship and Billing (CR&B) Enhancement project was allocated to the digital projects, with \$0.2 million allocated to MIMO. \$3.0 million of the \$6.8 million in 2022 historical capital for the Journey Work Product Transformation Teams project was also allocated to MIMO digital solutions.

Table 5. MIMO Digital Self-Service Capital (\$000s)

Line Item	Project Name	Year	Total Capital	Allocated to MIMO
21	CR&B Enhancement	2022	\$2,794	\$200
38	IVR Virtual Assistants	2022	\$1,161*	\$1,161
39	Journey Work Product Transformation Teams	2022	\$6,744	\$3,000
41	MIMO Web Self-Service	2023-2025	\$11,415	\$11,415
Total (2022-25)			\$22,114	\$15,776

*Net of 2023 reduction of (\$109,000), as shown in Exhibit A-12, Schedule B5.7.3

Q35. Can you elaborate on the scope of work that is being funded by the MIMO digital self-service capital?

A35. Yes. The focus for the MIMO digital self-service solutions in 2022-2023 was to enhance the existing MIMO Web, and MIMO start service Virtual Assistant (VA), solutions to address defects and cumbersome process flows that were preventing

Line
No.

1 customers from completing their transaction (2022-2023), to enhance and expand
2 the MIMO VA solutions to include start and transfer service request (2022), and to
3 migrate MIMO Web from an on-premise solution to the cloud (2022-2023).

4

5 Below is an overview of the types of MIMO digital self-service improvements that
6 were implemented from 2022-2023 through the Company's capital investments –
7 please note in 2022-2023 the four projects in Table 5 provided \$9.8 million in
8 capital to modify the customer systems as necessary to deliver the highlighted
9 improvements, while in 2024-2025 an additional \$6.0 million in capital is being
10 provided solely by the MIMO Web Self-Service project.

11

12 2022 MIMO Digital Improvements

- 13 • Implemented MIMO start and transfer service VA solutions.
- 14 • MIMO Web start-service migrated to a cloud-based platform, and in parallel
15 improved the stop MIMO user experience and interfaces (UX/UI).
- 16 • Allowed MIMO Web customers to enter only the last four digits of their social
17 security number to validate their identity.
- 18 • Removed and/or replaced confusing Web error messages.
- 19 • Removed redundant and confusing Web tiles.
- 20 • Created ability to validate international addresses – from customers moving to
21 DTE's service territory from outside the United States.

22

23 2023 MIMO Digital Improvements

Line
No.

- 1 • MIMO Web stop and transfer service migrated to a cloud-based platform, and
- 2 in parallel improved the overall MIMO stop and transfer service user experience
- 3 and user interface.
- 4 • Allowed authenticated Web customers to bypass identification requirements,
- 5 which was a common point of failure for existing DTE MIMO customers.
- 6 • Continued to improve the address search and validation MIMO Web
- 7 functionality, which was a significant point of failure for customers.
- 8 • Made it easier for customers who want to change the scheduled date of their
- 9 MIMO order by directing customers, via notifications and the MIMO online
- 10 order tracker, to the change order function in MIMO Web, and ensuring the
- 11 solution is easily navigated so they can complete their request.
- 12 • Incorporated Web chat across the MIMO Web transactions to provide
- 13 assistance to customers who get “stuck” in the process.

14

15 The focus for the Company’s 2024-2025 capital investments, will be to continue to

16 enhance the MIMO Web and VA solutions, with the goal of expanding the number

17 of MIMO scenarios that can be handled in a digital solution, and eliminating defects

18 and cumbersome process flows that are preventing customers from completing their

19 digital transaction.

20

21 2024-2025 MIMO Digital Improvements

- 22 • Additionally-enhanced user experience and user interface experience.
- 23 • Waiving identification requirements for customers who authenticate by logging
- 24 into the Web to process their MIMO request.

Line
No.

- 1 • Creating a Web stop service guest option, so customers do not have to login to
- 2 complete their stop service request.
- 3 • Eliminating Web technical errors, looping, blank page with error, and ad
- 4 blockers.
- 5 • Adding a Web chat link to all MIMO customer notifications.
- 6 • Expanding the Web and VA error logs to include secondary codes for improved
- 7 root cause identification.
- 8 • Fixing the defect related to document reversals, which are failing during a
- 9 digital move and requiring CR escalations.
- 10 • Implementing new VA skills to handle MIMO order changes, cancels and
- 11 inquiries.

12

13 **Q36. What are the realized and forecasted customer benefits of the identified scope**
 14 **of work funded by the MIMO digital self-service capital?**

15 A36. Enhanced and more effective MIMO Web start, stop, and transfer digital solutions,
 16 along with the implementation of the MIMO VA solutions, provided customers
 17 with more, and more effective, digital self-service solutions in which they could
 18 choose to engage to complete their MIMO request. As a result, the MIMO DER
 19 increased from 19% in 2020, to 42% in 2023 (Table 2), which has driven the
 20 number of MIMO calls to an all-time low of 530,000 in 2023 (Figure 5).

21

22 Given the results achieved to-date, the Company is forecasting that its historical
 23 and planned investments in the MIMO digital self-service solutions will increase
 24 the MIMO DER to 56% by 2027, will enable a cumulative decrease of 338,000
 25 calls (2023-2027), and will provide customers with a cumulative \$3.8 million in

Line
No.

1 O&M savings (2023-2027). The annual MIMO call volumes and associated O&M
2 savings are provided in Exhibit A-24, Schedule N5.

3

4 **Q37. Which projects support the expansion of the Outage digital transaction?**

5 A37. The Company invested \$7.8 million in 2022 historical period spend in two projects
6 to enhance and expand the Outage digital self-service solutions over the course of
7 12-months ending December 31, 2022, which are included in Exhibit A-12
8 Schedule B5.7.3, and which I have summarized in Table 6 below. \$6.3 million of
9 the \$14.9 million in 2022 historical capital for the Error Free Communications –
10 Outage Status project was allocated to Outage digital transaction. \$1.4 million of
11 the \$6.8 million in 2022 historical capital for the Journey Work Product
12 Transformation Teams project was also allocated to Outage digital transaction.
13 See Exhibit A-24 Schedule N3.1 Lines 30-32, 41 for additional project details.

14

15 **Table 6. Outage Digital Self-Service Capital (\$000s)**

16

Line Item	Project Name	Year	Total Capital	Allocated to Outage
35	Error Free Communication – Outage Status	2022	\$14,904	\$6,330
39	Journey Work Product Transformation Teams	2022	\$6,744	\$1,444
Total (2022)			\$21,648	\$7,774

17

18 **Q38. Can you elaborate on the scope of work that is being funded by the Outage**
19 **digital self-service capital?**

20 A38. Yes. Customers are very engaged in the use of the Outage digital self-service
21 solutions, as evidenced by the 96% Outage DER in 2023 (Table 2). However, the
22 record storm activity and resulting number of customer outages in 2021 and 2023,

Line
No.

1 have provided greater insight into the opportunities to enhance the Outage self-
2 service experience, and the quality of information the Company provides customers
3 during an outage.

4
5 The \$7.8 million in capital allocated to the Outage transaction reflects the entirety
6 of the Company's 2022 capital investments in its Outage digital self-service
7 solutions, and was used to improve the usability, ease-of-navigation, and quality of
8 the messaging and notifications provided to customers who were reporting or
9 checking on the status of storm related outages using the Web. I have summarized
10 these improvements below.

11

12 2022 Outage Web Improvements

- 13 • Ongoing enhancements to the newly launched (late 2021) Police/Fire,
14 Municipality, and Outdoor Lighting cloud site.
- 15 • Integrated Outage Web with the new "Where is My Order" (WISMO) and
16 Premise Power Status (PPS) Outage systems.
- 17 • Ongoing enhancements to the user experience and user interface and navigation
18 of the Web and Mobile Web Outage centers.
- 19 • Enhanced and more accurate customer-facing error messages.
- 20 • Integrated Web Outage with the new cognitive address search to make it easier
21 for customers to search and find address.
- 22 • Completed changes required to support the planned 2023 Advanced
23 Distribution Management System (ADMS) launch.

24

Line
No.

1 **Q39. What are the realized and forecasted customer benefits of the identified scope**
2 **of work funded by the Outage digital self-service capital?**

3 A39. The 2022 Outage Web self-service enhancements improved the visibility of the
4 Outage Web content, improved the quality of the information presented to
5 customers regarding their outage, and made navigation of the Outage Website
6 easier for customers, which resulted in increased numbers of customer reporting an
7 Outage to successfully complete their transaction in a digital channel – 87% in 2022
8 versus 92% in 2023 – and a corresponding increase in the Outage DER, which went
9 from 94% in 2022, to 96% in 2023 (Table 2).

10

11 The volume of mitigated calls from this increased DER is dependent on storm
12 activity, and the number of customers who are reporting an Outage, which
13 increased from 900,000 in 2022, to 2.9 million in 2023. As a result, Outage
14 reported by a CR increased from about 52,000 in 2022, to just over 125,000 in 2023,
15 more than doubling. However, Outage reporting through the digital self-service
16 solutions more than tripled from just over 850,000 in 2022 to 2.8 million in 2023,
17 indicating that significant numbers of customers chose to engage in the use of an
18 Outage digital solution rather than call to report their Outage, with 92%
19 successfully able to complete their transaction as compared to 87% in 2022.

20

21 Had the percent of successfully completed Outage digital transactions not increased
22 from 87% to 92%, as a result of the Company's 2022 capital investments, Outage
23 reporting calls to the Contact Center could have increased by over 157,000. This
24 assumes that 3.15 million Outage reports were attempted in a digital solution (2.9
25 million completed transactions / 92% completion rate), and that if the completion

Line
No.

1 rate in 2023 had remained at 87%, there would have been an additional over
2 157,000 failed digital Outage reports (3.15 million attempted in a digital solution x
3 5% decrease in percent completed), which could have resulted in a call to the
4 Contact Center.

5
6 Regarding the Company's 2023-2024 investments, the focus for the Outage
7 transaction in 2023-2024 is on the improvement of the timeliness and accuracy with
8 which we provide customer power status updates, restoration estimates, and other
9 outage information and notifications. These investments are part of the Company's
10 Error Free Communication (EFC) – Outage Status initiative, from which \$6.3
11 million (Table 6) was used to fund the described 2022 Outage Web improvements,
12 of which \$3.8 million was previously approved in the Commission's final order in
13 Case No. U-20836, as reflected in Exhibit A-24, Schedule N8, Page 2, Line 23.
14 Any required enhancements to the Outage digital self-service solutions from 2023-
15 2024 are in support of the EFC- Outage Status initiative, which I will discuss in
16 detail in Part 6 of my testimony related to "Projects that Enhance Customer
17 Interactions".

18
19 Cumulatively, the Company is forecasting its investments in the Outage digital
20 solutions to increase the Outage DCR to 95% by 2027, will enable a cumulative
21 decrease of 32,500 calls (2023-2027), and will provide customers with a net
22 cumulative \$0.4 million in O&M savings (2023-2027). The annual Outage call
23 volumes and associated O&M savings are included in Exhibit A-24, Schedule N5.

24

Line
No.

1 **Q40. Which projects support the enhancement and expansion of the Billing digital**
2 **solutions?**

3 A40. The Company will invest \$5.0 million in three projects to enhance and expand the
4 Billing digital self-service solutions over the course of 36-months ending December
5 31, 2024, consisting of \$3.5 million in 2022 historical period and \$1.5 million in
6 2023-2024 bridge period capital, as shown in Exhibit A-12 Schedule B5.7.3, which
7 I have summarized in Table 7 below. Note that \$0.4 million of the total \$2.8 million
8 in 2022 historical spend for the Customer Relationship and Billing (CR&B)
9 Enhancement project was allocated to the digital projects, with \$0.1 million
10 allocated to Billing. See Exhibit A-24 Schedule N3.1 Lines 10-12, 25-26 for
11 additional project details.

12

13 **Table 7. Billing Digital Self-Service Capital (\$000s)**

14

Line Item	Project Name	Year	Total Capital	Allocated to Billing
21	CR&B Enhancement	2022	\$2,794	\$100
27	Bill Management	2022	\$3,425	\$3,425
28	Billing Web Self-Service	2023-24	\$1,480	\$1,480
Total (2022-24)			\$7,699	\$5,005

15

16 **Q41. Can you elaborate on the scope of work that is being funded by the Billing**
17 **digital self-service capital?**

18 A41. Yes. The three projects in Table 7 are providing \$5.0 million in capital from 2022-
19 2024 to enhance the existing Billing digital solutions, which includes enhancing the
20 digital user experience by improving the quality of the data presented on the Web,
21 addressing defects in the online bill management tool, and enhancing the bill
22 management tool to support the Time-of-Day (TOD) rate implementation.

Line
No.

1 **Q42. Can you describe the scope of \$3.4 million in capital reflected in Table 7 that**
2 **was allocated to the Bill Management project?**

3 A42. Yes. In 2021, the Company launched a new online bill analyzer that consists of
4 two components, a bill impact analyzer and a bill simulator, that together provide
5 customers with an estimate of those items that impacted their current bill – usage,
6 weather, billing days – along with the ability to simulate their next bill based on
7 usage forecasts, and the impact of any usage reductions they could realize by
8 changing their behavior.

9
10 The Commission, in its final order in Case No. U-20836, approved for recovery
11 \$2.6 million in capital for the implementation of this new “Bill Management” tool,
12 as reflected in Exhibit A-24, Schedule N8, Page 1, Column b, Line 5. The Company
13 invested an additional \$3.4 million in the Bill Management tool in 2022 to address
14 identified defects, to continue to enhance the Billing experience, and to incorporate
15 the ability for the tool to effectively analyze and simulate Time-of-Day
16 (TOD) rates/bills, which were implemented in March of 2023.

17
18 **Q43. What are the realized and forecasted customer benefits of the identified scope**
19 **of work funded by the Billing digital self-service capital?**

20 A43. In 2022, customers completed over 6.2 million Billing transactions, with 5.5
21 million completed in a digital solution (89% DER), and 0.68 million completed
22 through a CR call. In 2023, total completed Billing transactions increased to 6.8
23 million, however, the number of transactions completed in a self-service solution
24 increased to 6.3 million (92% DER), while those completed through a CR
25 decreased to 0.55 million. This implies that while customer Billing inquiries

Line
No.

1 increased in 2023 due to the TOD implementation, significant numbers of those
2 customers chose to engage in a digital solution to handle their inquiries. In fact, in
3 2023, over 210,500 customers accessed the Company’s online bill management
4 tool, over 483,200 times, and over 113,700 customers used the Company’s high bill
5 inquiry VA over 159,300 times, to get answers to questions about their bill.

6
7 Given the results achieved to-date, the Company is forecasting that its historical
8 and planned investments in the Billing digital self-service solutions will increase
9 the Billing DER to 94% by 2027, will enable a cumulative decrease of 244,000
10 calls (2023-2027), and will provide customers with a net cumulative \$2.8 million
11 in O&M savings (2023-2027). The annual Billing call volumes and associated
12 O&M savings are included in Exhibit A-24, Schedule N5.

13
14 **Q44. Which projects support the expansion of the Payment digital transaction?**
15 A44. The Company will invest \$4.6 million in a project to enhance and expand the
16 Payment digital self-service solutions over the course of 36-months ending
17 December 31, 2025, as shown on Line 42 of Exhibit A-12 Schedule B5.7.3, and
18 which I have summarized in Table 8 below. See Exhibit A-24 Schedule N3.1 Lines
19 63-65 for additional project details.

20
21 **Table 8. Payment Digital Self-Service Capital (\$000s)**
22

Line Item	Project Name	Year	Total Capital	Allocated to Payments
42	Payment Web Self-Service	2023-25	\$4,553	\$4,553

23

Line
No.

1 **Q45. Can you elaborate on the scope of work that is being funded by the Payment**
2 **digital self-service capital?**

3 A45. Yes. The Company processes millions of customer payments every year, with the
4 majority of them completed using one of the Company's digital self-service
5 solutions, as indicated by the 84% 2023 Payment DER (Table 2). However, given
6 that the Company handles over 32 million payment transactions every year, even
7 small increases in the Payment DER significantly reduces call volumes.

8
9 In 2023, a minimal of amount (approximately \$50,000) of the \$4.6 million in
10 Payment Web Self-Service capital was focused on addressing known defects in the
11 Payment digital self-service solutions that were preventing customers from
12 successfully completing their transactions. This investment enabled an increase in
13 the percent of customers who were successfully completing their Payment digital
14 transaction from 76% in 2022 to 79% in 2023. In parallel with its focus on Payment
15 defect remediation in 2023, the Company increased customer awareness of the
16 availability of the Payment self-service solutions and made it easier for customers
17 to access those solutions through clickable links in email notifications and SMS
18 messages.

19
20 In 2024-2025, the Company is significantly increasing its capital investment in the
21 Payment digital self-service solutions to improve the Payment digital experience
22 by further increasing the percent of customers who are able to successfully
23 complete their digital Payment transaction, and to improve the experience for
24 customers intending to perform other transactions, as the current Payment digital
25 experience was originally designed and implemented in 2018 as a stand-alone

Line
No.

1 transaction; however, with the increase in digital transactions in Collections and
2 MIMO over the past few years, the Payment solution is being leveraged across
3 multiple transactions. As such, it is important that the Company invest in both the
4 Payment digital solutions, and Payment experience within the Collections and
5 MIMO digital solutions. I have summarized the planned Payment digital solution
6 improvements below.

7
8 2024-2025 Payment Digital Improvements

- 9 • Redesigning the online web payment center (authenticated version and guest
10 version) to improve the resiliency and the user experience and the user interface.
- 11 • Streamlining how other transactions integrate with the payment center (e.g.,
12 MIMO & Collections) to improve the user experience and technical
13 implementation process to integrate payments into other transactions.
- 14 • Eliminating failure points for both Authenticated Payments (i.e., customers who
15 log-in to their online account) and Guest Payments (i.e., customers who do not
16 log-in or who do not have an online account) that are preventing customers from
17 successfully completing their payment.
- 18 • Simplifying the process for Autopay customers to update their saved payment
19 methods, which today requires the customer to unenroll and reenroll in the
20 program and can lead to calls to a CR.
- 21 • Implementing more descriptive error messages, so that when customers fail in
22 their attempt to make a payment on the Web, they will know why and can
23 increase the likelihood of success on their next attempt.

Line
No.

1 **Q46. What are the realized and forecasted customer benefits of the identified scope**
2 **of work funded by the Payment digital self-service capital?**

3 A46. In 2022, the Company handled 32.84 million Payment transactions, of which 26.96
4 million (82% DER) were completed in a self-service solution, which for Payments
5 includes the Web, Mobile App, IVR, and Kiosk, as well as customers who use Auto
6 Pay and Electronic Funds Transfer (EFT). In 2023, the number of Payment
7 transactions increased to 32.92 million, but at the same time the volume of those
8 transactions completed in a self-service channel also increased to 27.80 million
9 (84% DER).

10

11 So, while the number of Payment transactions only increased by 0.2% (60,000
12 transactions) the number of Payment transactions in 2023 that were completed in a
13 self-service channel increased by over 3% (78,000 transactions). However, the
14 increase of 840,000 digital Payment transactions includes the transition of over
15 460,000 Payments that in 2022 were made through the mail, but were made
16 electronically through AutoPay in 2023. Therefore, the reduction in Payment call
17 volumes from 2022 to 2023 was a net 280,000 calls (Figure 5).

18

19 Given the results achieved to-date, the Company is forecasting that its historical
20 and planned investments in the Payment digital self-service solutions will increase
21 the Payment DER to 85% by 2027, which will enable a cumulative decrease of
22 ~360,800 calls (2023-2027) and provide customers with a cumulative ~\$4.1 million
23 in O&M savings (2023-2027). The annual Payment call volumes and associated
24 O&M savings are included in Exhibit A-24, Schedule N5.

25

Line
No.

1 **Q47. Are there other Customer IT capital projects that also support the Company's**
2 **call volume reduction efforts?**

3 A47. Yes. A total investment of \$1.4 million, consisting of \$0.5 million in 2023 and \$0.9
4 million in 2024 bridge period capital, from the Advanced Analytics Use Cases
5 project shown on Line 18 in Exhibit A-12, Schedule B5.7.3, also supports the
6 Company's call volume reduction efforts. Since \$0.4 million of the 2023 bridge
7 period capital has already been approved for recovery in U-20836, the Company is
8 seeking recovery for \$1.0 million of 2023 bridge period capital for this project in
9 the instant case. See Exhibit A-24 Schedule N8 Page 2, Column c, Line 3 for details
10 on the capital approved for recovery in U-20836 for the Advanced Analytics (AA)
11 Use Cases project. What follows is a description of the scope of each of the 2023
12 and 2024 analytics use case as they relate to providing call reduction benefits.

13

14 2023 AA Use Case - Scope and Benefits

15 In 2023, the Company spent \$0.5 million in capital to develop an analytics model
16 that uses Natural Language Processing (NLP) technology and Speech Analytics to
17 improve the accuracy with which customer calls are categorized, especially as it
18 relates to those calls that would often be manually categorized as "Other" by the
19 CRs. Through the use of advanced algorithms, we have seen call categorization
20 accuracy improve from 74% to 86%, with most of that improvement related to those
21 calls that would have been previously allocated to the "Other" category being more
22 appropriately categorized into one of the five key transactions. The analytics model
23 is also self-learning so it will be continually updating its categorization algorithm
24 and enhancing the process and its ability to provide even deeper insight over time
25 into customer calls and call patterns.

Line
No.

1

2

3

4

5

6

7

8

9

10

11

12

By dispositioning calls to the appropriate call categories, the Company is gaining greater visibility into the total volume and most common reasons for calls from customers across each of the five key transactions. This allows us to identify process and policy improvements with each transaction that will provide incremental call volume reductions. Through 2027, the use of the analytics model is forecasted to provide a cumulative incremental call volume reduction, beyond what is expected from our digital self-service projects, of ~30,000 calls, for total sustained O&M savings of ~\$340,000. The call volume and O&M cost reduction is reflected in Exhibit A-24, Schedule N5 (Page 2, footnote 7).

2024 AA Use Case - Scope and Benefits

13

14

15

16

17

18

19

20

21

22

23

24

25

In 2024, the Company is investing \$0.9 million to build an analytics model that will identify the precise touchpoints and scenarios in the various customer interactions that either cause a customer to call, or that result in a failure to successfully complete their interaction in a digital self-service solution. This first requires a complete mapping of the customer touchpoints for each customer interaction, followed by advanced analytics modeling and tools that will uncover the underlying reasons of why a customer chooses to call, as opposed to using a digital self-service channel, and why a customer who started in a digital self-service solution had to call the Company to complete their interaction. These efforts are expected to reduce 17,500 additional calls in 2024 through 2025, resulting in cumulative and sustained O&M savings of ~\$200,000. These call volume and the O&M cost reductions are reflected in Exhibit A-24, Schedule N5 (Page 2, footnote 8 and 9).

Line
No.

1 **Q48. Is the Company requesting cost recovery of any previously approved**
2 **Customer IT capital project investments in the instant case, and if so, why?**

3 A48. Yes. As set forth in Exhibit A-24, Schedule N8, there is \$13.3 million in 2022-
4 2023 capital, across eight projects (Page 2, Columns b through d, Line 1, Lines 5-
5 11), that I am sponsoring in my testimony in the instant case, of which \$5.7 million
6 (Page 2, Columns b through c, Line 3 and Line 13) was previously approved by the
7 Commission for cost recovery in Case No. U-20836. Additionally, there is \$5.7
8 million in 2021 digital self-service capital, across three projects (Page 2, Column
9 a, Line 13), that were also previously approved by the Commission for recovery in
10 U-20836, but that is not reflected in Exhibit A-12, Schedule B5.7.3 of the instant
11 case.

12

13 Despite their prior approval of this \$11.4 million in 2021-2023 capital, the
14 Commission in its final order in U-21297 disallowed for recovery the entirety of
15 these projects based on arguments made by the Detroit Area Advocacy
16 Organizations (DAAOs). Because the capital investments set forth in Exhibit A-
17 24, Schedule N8 were previously approved for cost recovery in Case No. U-20836,
18 and the Company relied on such approval when spending the capital, it is
19 appropriate for the Commission, in the instant case, to authorize cost recovery of
20 these capital investments to rectify the inadvertent retroactive disallowance that
21 resulted from the final order in Case No. U-21297.

22

23 **Q49. Is the Company providing a detailed cost-benefit analysis for its Digital Self-**
24 **Service projects?**

Line
No.

1 A49. Yes. The Company is providing a Net Present Value (NPV) analysis of its digital
2 self-service projects, the details of which can be found in Exhibit A-24, Schedule
3 N6.

4
5 **Q50. Please describe how the Company models the NPV for its Digital Self-Service**
6 **projects?**

7 A50. The NPV model determines the annual cost to customers that results from the
8 Company's recovery of the digital project cash outflows through the ratemaking
9 process, which is referred to as the "revenue requirement customer costs." This
10 includes the revenue recovery impact of the initial capital project costs, the project
11 cost-to-achieve O&M, and all of the ongoing sustainment capital and trailing O&M
12 costs. The model then calculates what is referred to as the "revenue recovery
13 customer savings," which is the difference between the annual digital project call
14 volume reduction O&M savings, and the annual project O&M costs, which
15 includes the digital project cost-to-achieve O&M and any ongoing project trailing
16 O&M costs.

17
18 The difference between the revenue requirement customer costs, and the revenue
19 requirement customer savings, determines the "net annual revenue recovery" cost
20 or (savings) to customers, which the model then discounts back to today's dollars
21 to determine the NPV to customers of the digital projects. A negative NPV implies
22 the projects are value creating for customers (i.e., saves customers money), while a
23 positive NPV would imply the projects are not value creating for customers (i.e.,
24 costs customers money).

25

Line
No.

1 **Q51. Which capital investments are included in the NPV model?**

2 A51. The NPV model, as reflected in Exhibit A-24, Schedule N6, includes all 2022-2025
3 capital projects that support the enhancement and expansion of the Company's
4 digital self-service solutions for each of the five key transactions, whose scope and
5 benefits are described in Part 4 of my testimony. Also included in the NPV model
6 are the previously described 2023 and 2024 AA Use Case capital project
7 investments, which as discussed are also intended to reduce call volumes and
8 deliver O&M savings for customers. Finally, the NPV model also includes \$12.0
9 million in 2021 digital self-service project capital, which was sponsored in my
10 testimony in DTE Electric Case No. U-21297 (MJH-41, Table 2).

11

12 **Q52. Why is the Company including 2021 digital capital in its NPV analysis if it is**
13 **not included in the historical, bridge, or test period capital in the instant case?**

14 A52. The 2021 digital investments are contributing to the realized and ongoing
15 reductions in call volumes, which are reflected in the NPV model and included in
16 the NPV calculation. As such, it would be disingenuous to include the call volume
17 reduction savings in the NPV analysis, but to exclude the revenue recovery cost to
18 customers of the 2021 capital investments, as doing so would inflate the NPV.

19

20 **Q53. What is the NPV of the Company's digital self-service projects?**

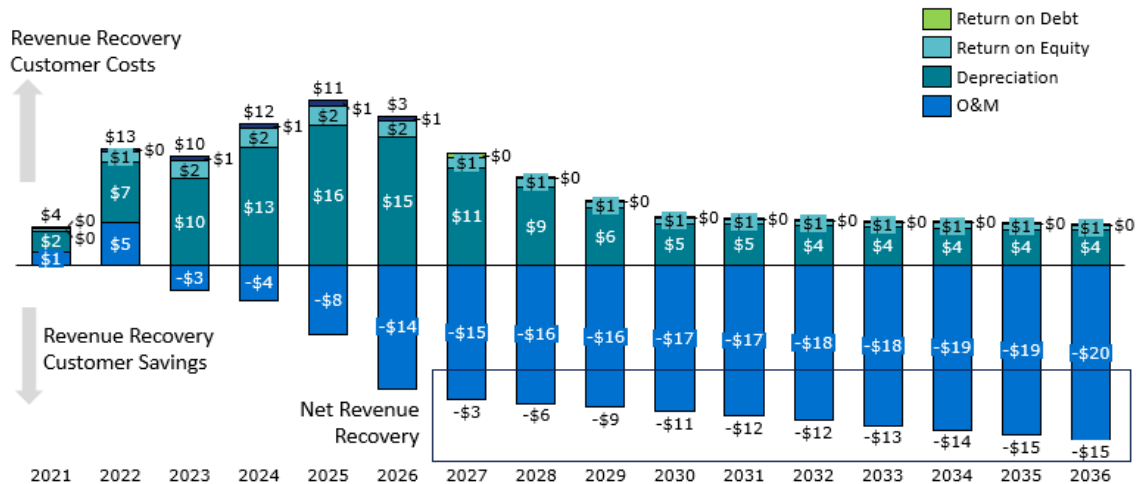
21 A53. The NPV of the Company's digital self-service capital projects has been determined
22 to be a negative \$5.6 million, which confirms that the digital self-service
23 investments are value creating for customers, as reflected in Exhibit A-24 Schedule
24 N6, Line 23, Column (h). I am providing a summary of the results of the NPV
25 analysis in Figure 8.

Line
No.

1

2

Figure 8 - Digital Self-Service Project NPV (\$ millions)



3

4

5

6

7

8

9

10

11

12

13

14

15

16

17

As seen in Figure 8, customers start to realize net revenue recovery savings in 2027 (i.e., current year revenue recovery savings are greater than current year revenue requirement costs). These annual net savings continue to grow to an annualized \$15.3 million by 2036 and are sustained in perpetuity as reflected on Exhibit A-24 Schedule N6, Line 22, Columns n through w.

I would note here that the \$12.0 million in 2021 digital self-service capital included in the NPV analysis, was part of the \$51.3 million in total digital self-service capital for which the Company was seeking recovery in U-21297, and which was subsequently disallowed for recovery in its entirety by the Commission in its final order in that case. As such, the Company believes that its analysis conservatively calculates the NPV of the digital self-service projects because customers are currently not incurring the associated revenue recovery costs of the \$12.0 million in 2021 capital. Should the Commission authorize recovery of the previously

Line
No.

1 discussed \$5.7 million in 2021 digital self-service capital originally approved in
2 Case No. U-20836 (See Exhibit A-24 Schedule N8, Page 2, Column a, Line 13),
3 customers would still only be incurring the revenue recovery cost of less than half
4 of the \$12.0 million in 2021 digital capital.

5

6 **Part 5. Operational Efficiency Projects**

7 **Q54. What is included in this section of your testimony?**

8 A54. This section of my testimony will include a discussion of projects that align with
9 enabling operational efficiencies and stability in the Contact Center, Billing, and
10 the Revenue Management and Protection (RM&P) groups. I will also discuss
11 projects in which the Company is leveraging advanced analytics to capture
12 operational efficiencies that improve the customer experience and provide cost
13 savings. Additionally, I will discuss how we are also investing capital in projects
14 that improve the quality and efficiency of the Customer CR&B system, and with
15 which the Company implements its Customer IT projects.

16

17 **Q55. Can you please describe projects that deliver operational efficiencies in the**
18 **Contact Center?**

19 A55. Yes. The Company is investing a total of \$2.5 million in capital, consisting of \$2.1
20 million in the 2023-2024 bridge period and \$0.4 million in the 2025 test period, in
21 two projects that will enhance the ability of the Contact Center to reduce the
22 Average Handle Time (AHT) of calls from customers, and that will improve
23 customer accessibility to the telephony systems during peak call times, such as
24 during a major storm event. These projects are both included in Exhibit A-12,
25 Schedule B5.7.3, and are summarized below.

Line
No.

1

2

1. Line 30 – Contact Center Enablement

3

The Commission previously approved, in its final order in Case No. U-21297, \$0.7 million in 2023-2024 capital for the Contact Center Enablement project, which enhances the Customer Relationship Management (CRM) system for the Collection transaction to reduce its AHT. The Company's actual spend for this project was \$1.3 million in capital .. The incremental spend of \$0.6 million was due to emergent scope in 2023 that resulted from the complexity of the required enhancements, which necessitated engaging the services of additional SAP consultant resources. Additionally, in 2025, the Company is forecasting to spend another \$0.4 million to make similar enhancements in CRM to reduce AHT across the other key transactions. This incremental capital is reflected in Exhibit A-24 Schedule N9, and brings the total capital spend for this project to \$1.7 million.

14

15

Therefore, in the instant case, the Company is seeking recovery of a total of \$1.0M in incremental capital for this project, which includes the incremental \$0.6 million that was required to complete the 2023 Collection scope, plus the additional \$0.4 million in capital to reduce the AHT of the other key transactions support. See Exhibit A-24 Schedule N3.1 Line 18 for additional project details.

20

21

2. Line 45 – SIP in Contact Center

22

The efficiency with which the Company manages and maintains its telephony systems, including the IVR, significantly impacts the accessibility of these systems for our customers. This is especially true in periods of increased customer usage,

23

24

Line
No.

1 such as during a significant customer outage event or during the application of
2 required software patches and upgrades.

3

4 The Commission previously approved, in its final order in Case No. U-21297, \$1.7
5 million in 2022-2024 capital for the SIP in Contact Center project. The Company
6 actually spent \$0.9 million in 2023 to complete the project, as reflected in Exhibit
7 A-12, Schedule B5.7.3. The \$0.8 million reduction in total capital, versus what was
8 previously approved, is because the Company was able to leverage cost synergies
9 gained from the implementation of other projects, which reduced the time, effort,
10 and resources required. As such, there is no incremental capital associated with
11 this project for which the Company is seeking recovery in the instant case.

12

13 **Q56. How is the Company investing capital to improve operational efficiency in**
14 **Billing?**

15 A56. In October 2022, DTE launched a new Meter Data Management (MDM) system to
16 replace an outdated and unsupported DTE IT solution. Since that time, the
17 Company has identified opportunities to enhance the new MDM solution to reduce
18 billing exceptions, reduce manual work, improve forecasting, and prevent delayed
19 bills for its largest commercial and industrial customers. To fund these
20 enhancements the Company is investing \$1.8 million in 2025 test period capital in
21 the Meter Data Management (MDM) Stabilization project, as reflected on Line 23
22 of Exhibit A-12 Schedule B5.7.3.

23

24 These enhancements will reduce by 80% the number of manual touches (~12,000)
25 currently required to remediate exceptions and prevent delayed bills, providing

Line
No.

1 ~\$100,000 annually in O&M savings. The MDM project will also reduce
2 potentially higher energy market settlement charges due to forecasting errors from
3 estimated commercial and industrial load. See Exhibit A-24 Schedule N3.1 Line
4 42 for additional project details.

5

6 **Q57. How is the Company investing capital to improve operational efficiencies in its**
7 **RM&P group?**

8 A57. The Company is investing \$0.4 million in 2025 test period capital to improve the
9 management of instances of theft and fraud with the Never Billed Accounts due to
10 Theft / Fraud project (Exhibit A-12, Schedule B5.7.3, Line 24). The Commission
11 previously approved, in its final order in Case No. U-21297, \$0.4 million in 2024
12 capital for this project. However, the project has been re-timed to 2025 to provide
13 capacity for other more urgent IT projects. The Company is seeking continued
14 recovery of this capital in the 2025 test period in the instant case.

15

16 As discussed in U-21297, this project creates new functionality in the core billing
17 system that will provide a new screen for the Revenue Management and Protection
18 (RM&P) Exceptions Team to utilize when a customer needs to be billed for theft,
19 ID fraud, or bankruptcy, and the normal billing process cannot be used. As no bill
20 is generated today, the account does not progress through the collection (SAP
21 dunning) process. Since the SAP CR&B system went live in April 2017 through
22 March 1, 2024, ~\$1.6 million in charges have accrued on customer accounts that
23 have not been billed and are aging in active arrears. See Exhibit A-24 Schedule
24 N3.1 Line 61 for additional project details.

25

Line
No.

1 **Q58. How is the Company leveraging Advanced Analytics to capture operational**
2 **efficiencies and optimize customer programs and processes to reduce**
3 **uncollectible expense (UCX) and O&M costs?**

4 A58. DTE is investing in analytics resources and technologies that will provide greater
5 insight into customer segments, behaviors, and improving the customer experience.
6 To that end, the Company is investing \$6.6 million in capital, consisting of \$1.1
7 million in the 2022 historical period, \$2.5 million in the 2023-2024 bridge period,
8 and \$3.0 million in the 2025 test period, in the Advanced Analytics (AA) Use Cases
9 project as shown on Line 18 of Exhibit A-12, Schedule B5.7.3.

10

11 The Commission, in its prior order in U-20836, previously approved \$1.5 million
12 in 2022-2023 capital for investment in Advanced Analytics use cases, to enable the
13 Company to gain a deeper understanding of our customers, customer segments, and
14 customer behaviors and preferences. See Exhibit A-24 Schedule N8 Page 2,
15 Columns b through c, Line 3 for details. As such, in the instant case, the Company
16 is seeking recovery of an additional \$5.1 million in capital for the implementation
17 of new analytics use cases, which includes \$1.0 million in capital for the 2023 AA
18 use case (\$0.1 million) and the 2024 AA use case (\$0.9 million) that I discussed in
19 Part 4 of my testimony because they support achievement of the Company's call
20 volume reduction commitments and provide O&M cost savings in 2023-2027. The
21 remaining \$4.1 million in capital, for which the Company is seeking recovery, will
22 be allocated to the 2024 and 2025 AA use cases to be described below that will
23 leverage advanced algorithms and machine learning to optimize customer programs
24 and processes to reduce uncollectible expense (UCX) and O&M costs. Specific
25 capital investment dollars and the customer benefit provided by the project is

Line
No.

1 described and delineated for each individual 2024 and 2025 AA use case, just as
2 they were for each 2023 and 2024 AA use case that contribute to call volume
3 reduction described in Part 4. See Exhibit A-24 Schedule N3.1 Lines 3-6 for
4 additional project details.

5
6 1. 2024 Energy Assistance AA Use Case – \$1.1 million

7 The Company is investing \$1.1 million in 2024 bridge period capital to develop a
8 machine learning model to optimally allocate available energy assistance paired
9 with Energy Waste Reduction (EWR) to eligible low-income customers. Today,
10 energy assistance is available to DTE Electric low-income customers whose
11 balances are past due or who otherwise qualify for assistance. This support assists
12 customers in paying down their arrears and can help them avoid a disconnection
13 due to non-payment in the short-term. However, for a more comprehensive, long-
14 term approach to assisting them in reducing their bills and managing their arrears,
15 a combined offering of energy assistance along with EWR funding would be more
16 effective. This AA use case funds development of a machine learning solution to
17 identify eligible customers for both energy assistance and EWR. When the model
18 indicates eligibility for both programs, a bundled offering will then be extended to
19 these low-income customers, who may not have been aware of their eligibility to
20 access both programs and how to apply for this support.

21
22 While traditionally customers seeking energy assistance funds must reach out to
23 DTE or third-party agencies to start the process, instead we would be able to
24 leverage the machine learning model to match customers with EWR and energy
25 assistance program(s) that best fit their needs and circumstances, simplifying the

Line
No.

1 process. Through a more effective and optimal means of distributing energy
2 assistance and helping our low-income customers to better manage their bills with
3 EWR, we estimate that this offering can reduce customer arrears and UCX by
4 \$300,000 in 2024 through 2025.

5

6 2. 2025 AA Use Case – Reducing MPSC Complaints – \$1.0 million

7 The Company is investing \$1.0 million in 2025 test period capital to develop a
8 machine learning model to understand the drivers underlying Customer Service
9 MPSC complaints and make recommendations for improvements in our key
10 transactions, especially in Collection and Billing, which generate ~80% of
11 Customer Service complaints. Collection and Billing calls also have longer call
12 handle times at 12.6 minutes and 11.2 minutes, respectively, as compared to the
13 average of 10.5 minutes across all call types. The Company will leverage the
14 model's output to anticipate customer pain points that may be leading to their
15 dissatisfaction and frustration, and proactively reach out to these customers to
16 understand their concerns and resolve their issue before it becomes a MPSC
17 complaint. The model's output will also be integrated into our customer systems
18 so that if a customer who is likely to complain calls, the CRs can more swiftly
19 escalate the customer's issue for resolution. We anticipate that the actions taken to
20 address the drivers of customer complaints through process improvements in our
21 key transactions and taking proactive steps will reduce 110 or ~15% of Customer
22 Service MPSC Complaints (based on 2023 data) over a five-year period starting in
23 2026, and will provide operational efficiencies by reducing the volume of
24 complaints and better dedicating the same resources to focus on effectively
25 resolving the customers pain points that lead to complaints.

Line
No.

1

2

3. 2025 AA Use Case - Automating CR Notes – \$2.0 million

3

4

5

6

7

8

9

10

11

12

13

14

15

16

17

18

19

20

21

22

23

24

Q59. What IT efficiency projects are intended to improve the quality and efficiency of the Customer CR&B system and with which the Company develops and deploy Customer IT projects and reduce system downtime?

Line
No.

1 A59. The Company is investing \$9.1 million in 2022 historical period, 2023-2024 bridge
2 period, and 2025 test period capital in five IT efficiency projects that will be
3 discussed in the order they appear in Exhibit A-12, Schedule B5.7.3. Together,
4 these projects are intended to:

5

- 6 • Reduce the frequency and associated remediation and monitoring costs of
7 CR&B system outages;
- 8 • Remediate defects and make minor enhancements to the CR&B system;
- 9 • Accelerate the development, quality assurance review, and testing of Customer
10 IT projects; and
- 11 • Ensure the up time of customer systems and applications through optimization
12 of the flow of work and load on the system.

13

14 The Commission previously approved, in its final order in Case No. U-21297, \$8.3
15 million in 2022-2024 capital for these projects. The \$0.8 million increase in capital,
16 versus what was previously approved, is a result of the net impact of increases and
17 decreases in the individual projects, which I describe below.

18

19 1. Line 19 – Automated Application Monitoring Enhancement

20 The Company is investing a total of \$2.7 million in capital, consisting of \$1.5
21 million in the 2022 historical period, \$0.3 million in the 2023 bridge period, and
22 \$0.9 million in the 2025 test period, in this project. The Commission, in its prior
23 order in Case No. U-21297, previously approved for recovery a total of \$3.3 million
24 in 2022-2024 capital for this project.

25

Line
No.

1 While the total capital cost of \$2.7 million for this project is \$0.6 million less than
2 the \$3.3 million in capital that was approved for cost recovery in U-21297, \$0.9
3 million of capital has been to re-timed from 2024 to 2025, which will allow us to
4 evaluate the performance of the monitoring that has been implemented in 2022-
5 2023. As such, while the Company is not seeking recovery of additional total
6 capital for this project, it is seeking in the instant case recovery of the \$0.9 million
7 in the 2025 test period, which will complete the originally approved scope, and
8 expands the scope to include implementation of the Focus Build, Focus Insights,
9 and Customer Code Management modules.

10

11 Focus Build manages requirements and software development for large, agile
12 innovation projects. Custom Code Management is the central point of access for all
13 functions that are used to monitor and manage the complete lifecycle of custom
14 developments from requirement to retirement. Focus Insights manages Focus Build
15 and distributes powerful customer-specific dashboards in minutes providing a state-
16 of-the-art user experience. See Exhibit A-24 Schedule N3.1 Line 9 for additional
17 project details.

18

19 2. Line 21 – Customer Relationship and Billing Program Enhancement

20 The Company is investing total capital of \$4.0 million in enhancements to the
21 CR&B system that support improved customer experiences across the five key
22 transactions, which consists of \$2.8 million in the 2022 historical period, and \$1.2
23 million in the 2023 bridge period. The Commission in its final order in Case No.
24 U-21297, previously approved \$2.0 million in 2022 capital for this project. The
25 additional \$2.0 million in capital, for which the Company is seeking recovery in

Line
No.

1 the instant case, results from increased spending of \$0.8 million in 2022 to fund
2 emerging enhancement opportunities, and \$1.2 million of new capital spend in
3 2023, which funded newly identified opportunities for enhancement. See Exhibit
4 A-24 Schedule N3.1 Lines 25-26 for additional project details.

5
6 The majority of these 2022-2023 CR&B enhancements were related to the MIMO,
7 Collection, and Billing transactions, and were intended to increase First Contact
8 Resolution (FCR), which is a measure of the Company's ability to address a
9 customer's request or inquiry, over the phone or in a digital channel, on the first
10 try, without the customer having to reach out repeatedly. Overall, these investments
11 resulted in an increase in the average FCR, across the five key transactions, from
12 84% 2021 to 86% in 2023. With over 43 million transactions completed each year,
13 every 1% increase in FCR impacts the experience of a significant number of
14 customers, making it easier for them to complete their transaction, and avoiding the
15 frustration that comes with having to repeatedly contact the Company to resolve
16 their inquiry or request. Below are examples of the types of enhancements funded
17 by the total 2022-2023 capital for each transaction.

18

19 2022-2023 MIMO CR&B Enhancements

20 A total of 99 defects and enhancements were remediated and implemented in 2022-
21 2023 for the MIMO transaction, which enabled an increase in the MIMO FCR from
22 87% in 2021 to 89% in 2023, with some of the more significant examples described
23 below.

24

Line
No.

- 1 • Updated the arrangement of Customer Relationship and Management (CRM)
- 2 screens used by the Customer Service Representatives (CRs) – providing a
- 3 better call handling experience for customers and lower AHT.
- 4 • Created new notification templates for Force Move-Out customers, ~40% of
- 5 the move-out population and for whom we have never sent notifications.
- 6 • Updated the WISMO (“Where is my order?”) refresh rate so that the MIMO
- 7 Order Tracker provides near real-time data from 15 minutes to 1 minute.
- 8 • Incorporated “clickable” links and information bubbles for the CRs through the
- 9 MIMO screens in CRM – reducing customer wait times and AHT.
- 10 • Established the ability to Web register customers during the MIMO process in
- 11 CRM – at inception we observed a 200-300% daily increase.
- 12 • Enhanced the system to perform a check so that a customer is not erroneously
- 13 assigned more than one contract account at the same premise / address when
- 14 the account is being created, eliminating the risk of customers receiving
- 15 multiple billing statements.
- 16 • Supported the new VA functionality to allow customers to create a Move-in or
- 17 Move-out using the VA, reducing the number of customers transferred to a CR.
- 18 • Created functionality to allow customers starting service with a known lease-
- 19 end date to schedule a Move-out and not have to call DTE again.
- 20 • Created functionality within CRM that allows a CR to click on a link for
- 21 additional instruction on how to complete the customer transaction. Reduces
- 22 handle time per call and prevents unnecessary escalations.
- 23 • When a customer transfers service within the DTE service territory, we will
- 24 now automatically transfer their LSP plan with them. This prevents additional
- 25 calls from the customer to transfer their plan.

Line
No.

- 1 • Removed barriers that made web registration more difficult for customers,
2 allowing them to perform future transactions in self-service channels.
- 3 • Added error codes to CRM that allowed us to better diagnosis and remedy VA
4 failures so that the process can work more frequently for customers.

5

6 2022-2023 Collection CR&B Enhancements

7 A total of 150 defects and enhancements were remediated and implemented in
8 2022-2023 for the Collection transaction, which enabled an increase in the
9 Collection FCR from 78% in 2021 to 79% in 2023, with some of the more
10 significant examples described below.

11

- 12 • Updated the 65 New Closed Loop emails and added SMS to keep customers
13 informed of where they are in the collection process (SAP Dunning), improving
14 our communications with the customer.
- 15 • Upgraded the Payment Kiosk to accept payments on customer accounts that
16 were disconnected for non-payment.
- 17 • Automated Senior Flag to update when a customer reaches the age of 65. This
18 flag protects Seniors from disconnection due to non-payment as part of the
19 Winter Protection Plan (WPP), annually from November 1 through March 31.
- 20 • Refinements to optimize the collection process (SAP Dunning) to reduce
21 growth in arrears and potential write-offs and UCX.
- 22 • Notification enhancements to proactively give customers information regarding
23 their accounts, landlord accounts, payment plan updates, and payment
24 extension status.

Line
No.

- 1 • CRM enhancements to allow transactions to function properly including
- 2 customer refunds, completing theft service orders, payment allocations,
- 3 ensuring accurate LIA/RIA enrollment status, and low-income verification.
- 4 • Web/VA work to ensure we are offering customer appropriate solutions for
- 5 Payment extensions and Payment Agreements, and to update customers of lock
- 6 status so they know they are not at risk of a disconnect due to non-payment.
- 7 • Updated the cash only flag logic so that good paying customers are not impacted
- 8 and forced to change payment method.

9

10 2022-2023 Billing CR&B Enhancements

11 A total of 50 defects and enhancements, some related to TOD, were remediated and
12 implemented in 2022-2023 for the Billing transaction, with some of the more
13 significant examples described below. From 2021 through 2023 Billing FCR has
14 held steady at 75% despite remediating defects from the 2023 full implementation
15 of Time-of-Day rates. Some of the more significant examples described below.

16

- 17 • Billing system “sum check” calculation, as well as usage check calculations so
- 18 that customers do not receive bills with substantial errors.
- 19 • Updates to CRM to increase the visibility of customers enrolled in a billing
- 20 program and or payment plan to include Flexible Due Date, Reduced Bill
- 21 Frequency, My Bill, My Time, and CoolCurrents.
- 22 • Ability to compare DTE Gas rates versus an Alternative Service Provider’s rate.
- 23 • Improved the productivity of internal business users when querying and
- 24 viewing the status and statistics for Billing business exceptions.

Line
No.

- 1 • Banner Letter enhancements to provide customers detailed information
- 2 regarding an account's adjustments or billing corrections.
- 3 • Supported CRM enhancements related to MPSC rate case implementation to
- 4 ensure billing accuracy and to help customers enroll and unenroll in rates more
- 5 efficiently such as for the Dynamic Peak-Pricing (D1.8) rate.
- 6 • Enhancements to reduce the manual touches need during the monthly billing
- 7 process for our Major Accounts (Assigned Customer) Team.
- 8 • Enhancements to e-bill process to increase customer adoption rate and improve
- 9 the customer experience.

10

11 3. Line 22 – IT Application Environments Enhancement

12 The Company invested a total of \$0.5 million in capital in the IT Application
13 Environments Enhancement project, which consisted of \$0.2 million in the 2022
14 historical period, and \$0.3 million in the 2023 bridge period, to create a new Quality
15 Assurance (QA) environment. The total capital cost for this project included in the
16 instant case, is \$0.4 million less than the \$0.9 million in 2022-2024 capital that was
17 previously approved for cost recovery by the Commission in Case No. U-21297.

18

19 The project was completed in 2023, a year ahead of schedule and with favorability
20 to its budget, due to efficiencies that were realized by the selected vendor. As such,
21 although DTE Electric is not seeking recovery of any incremental capital for this
22 project in the instant case, the Company is including the project here to explain the
23 significant favorable variance relative to what was approved for recovery.

24

25 4. Line 25 – Supporting Capabilities Test Data and Test Data Management

Line
No.

1 The Company invested the net amount of \$0.9 million in capital in the 2022
2 historical and 2023 bridge period to establish a process to generate automated test
3 data and test scripts. The Commission, in its final order in Case No. U-21297,
4 approved for recovery \$1.2 million in capital for this project. The reason for the
5 reduced capital spend of \$0.3 million is that because during the execution phase,
6 the anticipated need for additional infrastructure (servers), and corresponding labor,
7 were found to be unnecessary. Although DTE Electric is not seeking recovery of
8 any incremental capital for this project in the instant case, the Company is including
9 the project here to explain the favorable variance relative to what was approved for
10 recovery.

11

12 5. Line 26 – Transform and Modernize PO Architecture

13 The Company will invest \$1.0 million in 2025 test period capital to transform and
14 modernize the Process Orchestration (PO) architecture to alleviate system
15 bottlenecks due to network traffic and growing functionalities in the CR&B system.
16 The Commission, in its final order in Case No. U-21297, approved for recovery
17 \$1.0 million in 2024 capital for this project. This project has since been rescheduled
18 into 2025, and as such, we are including it here as part of the Company's request to
19 approve this project for recovery in the 2025 test period in the instant case. Below
20 is a summary of the scope of the project, along with an updated view of the
21 associated customer benefits, which have been determined to be more significant
22 than originally forecasted.

23

24 This project remains critical. As the Company enables more capabilities in its
25 customer channels and the CR&B system, it creates additional stress and burden

Line
No.

1 for the PO to ensure increasingly complex jobs and functions perform as expected.
2 During periods of high traffic, such as during a storm or in the fall with the influx
3 of college move-ins, the Company's transactional system and digital channels must
4 scale up to handle the additional workload or risk an unplanned system outage. By
5 upgrading the PO to a more robust architecture, DTE Electric will be able to reduce
6 unplanned system outages that disrupt the Company's ability to serve customers
7 either digitally or through the Contact Center.

8
9 While the system is typically back up in ~3 hours during an unplanned outage, it
10 takes at least eight hours to identify the root cause and implement a longer-term fix
11 to stabilize the system. The cost of CRs who wait for the system to be restored
12 during unplanned system outages could be considerable. If it takes ~3 hours for the
13 system to come back up, assuming we are able to reduce unplanned system outages
14 from 10 to 3 by 2028, by multiplying this idle / wait time by the average number of
15 CRs per year between 2026 and 2028 and the hourly labor cost of a CR, this project
16 can reduce the O&M cost of CR wait time by ~\$310,000. See Exhibit A-24
17 Schedule N3.1 Line 87 for additional project details.

18

19 **Part 6. Projects that Enhance Customer Interactions**

20 **Q60. Can you describe the Company's rationale for investing capital in projects**
21 **that will enable "Enhanced Customer Interactions"?**

22 A60. The Company's strategy to enhance customer interactions is simple – improve the
23 customer experience and the effectiveness and efficiency with which the Company
24 manages customer interactions, by prudently investing in capital projects that
25 enable end-to-end monitoring of customer interactions, which provide customers

Line
No.

1 and employees full transparency into the status of these interactions, and that
2 improve the quality of the data and information provided to customers during these
3 interactions.

4

5 **Q61. Which of the capital projects you are sponsoring in your testimony are**
6 **intended to “Enhance Customer Interactions”?**

7 A61. There are five projects I will discuss in my testimony that are intended to Enhance
8 Customer Interactions, three of which are included in Exhibit A-12, Schedule
9 B5.7.3, which I am sponsoring, and two of which are included in Exhibit A-12,
10 Schedule B5.4 Technology and Automation, which is co-sponsored by Company
11 Witness Hartwick (see below).

12

13 Exhibit A-12, Schedule B5.7.3

- 14 • Line 31 – Customer Closed Loop Development
- 15 • Line 33 – Customer Service Communications – Phase 2
- 16 • Line 35 – Error Free Communication – Outage Status

17

18 Exhibit A-12, Schedule B5.4, Distribution Plant - Technology and Automation

- 19 • Page 18 – Line 33 – Operational Technology and EFC
- 20 • Page 18 – Line 40 – Other Modernize Grid Management

21

22 **Q62. Can you describe the Company’s investment in the Customer Closed Loop**
23 **Development project?**

24 A62. Yes. The Commission, in its final order in Case No. U-21297, approved for
25 recovery \$1.4 million in 2023-2024 capital for this project. The Company’s actual

Line
No.

1 investment totaled \$1.8 million in capital in the Customer Closed Loop
2 Development project, consisting of \$0.3 million in the 2022 historical period, and
3 \$1.5 million in the 2023 bridge period, as shown on Line 31 of Exhibit A-12,
4 Schedule B5.7.3. The 2022 historical spend of \$0.3 million was previously
5 approved in Case No. U-20836 as shown in Exhibit A-24 Schedule N8 on Page 2,
6 Column b, Line 22.

7

8 The \$0.4 million in additional capital the Company spent on this project, relative to
9 what was approved for recovery in U-21297, is due to the \$0.3 million in capital
10 the Company spent in 2022, which as stated was previously approved in Case No.
11 U-20386, but was subsequently disallowed in U-21297 due to being part of the
12 \$51.3 million in digital self-service projects, and which was used to complete the
13 scope of work for the MIMO and Collection transactions, plus the incremental
14 spending of \$0.3 million in capital in 2023 to complete the scope of the Billing and
15 Payment Closed Loop notifications, which was offset by \$0.2 million in 2024
16 capital that was previously approved in U-21297 but that is no longer required. As
17 such, the Company in the instant case is seeking recovery of an additional \$0.4
18 million in capital for this project. Included below is the 2023 scope and benefits
19 realized from the incremental investment in the Billing and Payment Closed Loop
20 notifications.

21

22 The intent of the investment in Closed Loop Billing and Payment notifications was
23 to provide customers greater visibility into their Billing and Payment interactions,
24 to share with them clear and concise communications related to those interactions,
25 and to provide them clickable links that would allow to track the status of these

Line
No.

1 interactions in a digital self-service solution. Below I describe some of the Closed
2 Loop Notifications that were enhanced or newly developed with the 2023
3 investment. See Exhibit A-24 Schedule N3.1 Lines 20-21 for additional project
4 details.

5

6 Billing Closed Loop Notifications

7 All Billing notifications had an update component (i.e., SMS function added) or
8 were newly developed in this project. The new Closed Loop notifications were
9 added where the customer would benefit from more visibility into their billing
10 transaction. One such update was with the Flexible Due Date (FDD) Process with
11 manual communications. This was addressed by automating all FDD
12 communications via email or SMS. This notification informs customers that their
13 request for Flex Due Date has been received and provides updates throughout the
14 process (received, being reviewed, eligible, or ineligible). This level of visibility
15 either did not exist for customers before the project or was being sent inconsistently.
16 Below is the list of Billing Closed Loop notifications that were updated or newly
17 developed.

18

- 19 • BudgetWise Billing enrollment / unenrollment
- 20 • eBill enrollment / unenrollment
- 21 • eBill ready to view notifications.
- 22 • Flexible Due Date request
- 23 • Meter tests updates and status
- 24 • Billing investigations status

Line
No.

- 1 • BudgetWise Billing Program status

2

3 Payments Closed Loop Notifications

4 All Payment notifications were reviewed for completeness and accuracy in their
5 messaging and to incorporate modern language as advised by Corporate
6 Communications. New Closed Loop notifications were added where the customer
7 would benefit from more visibility into their payment transaction, such as for
8 Autopay where there was not an email and SMS notification previously for
9 Autopay withdrawals. The new AutoPay notifications informed customers if the
10 AutoPay did not withdraw (for reasons described in the notification) and that a
11 manual payment would be required. This visibility did not exist for customers
12 before the project. Through our voice of the customer surveys, customers indicated
13 that notifications were important for communicating completion and confirmation
14 of their payment status. Below is the list of Payment Closed Loop notifications
15 that were updated or newly developed.

16

- 17 • Payment due reminders
- 18 • Payment cancelled
- 19 • Payment past due reminders
- 20 • Payments declined
- 21 • Credit card expiring
- 22 • Autopay withdrawal issues

23

Line
No.

1 As with MIMO and Collection Closed Loop notifications, the Billing and Payment
2 notifications are expected to reduce customer calls and increase FCR and customer
3 satisfaction.

4

5 **Q63. Can you describe the Customer Service Communications – Phase 2 project?**

6 A63. Yes. The first phase of the Customer Service Communications was approved for
7 recovery in Case No. U-21297, which included \$3.3 million in capital for the
8 implementation of a new notification platform – Message Broadcast – the scope of
9 which was completed in 2023. The Company, in the instant case, is seeking
10 recovery of \$2.0 million in 2024 bridge period capital, as reflected in in Exhibit A-
11 12, Schedule B5.7.3, Line 3, to complete Phase 2 of the project, which includes
12 the migration of 99% of all customer notifications to the new Message Broadcast
13 platform, and the leveraging of the new platform to enhance the quality and
14 effectiveness with which we communicate with customers. This includes the
15 ability to create, customize, catalog, and store customer notifications with delivery
16 confirmation, so that we have visibility into which customers did not receive which
17 notifications, and the use of the platform’s tools to ensure the integrity of the
18 customer contact data, to quickly create Messages On Demand (MODs) by an
19 assortment of methods, including list, zip code, electrical device, and geography,
20 and to be able to provide customers the ability to communicate with us via
21 SMS/texting. See Exhibit A-24 Schedule N3.1 Line 28 for additional project
22 details.

23

24 **Q64. Can you provide an overview of the Company’s EFC – Outage Status**
25 **initiative?**

Line
No.

1 A64. Yes. In simple terms, the Company determined that it needed to transition from a
2 “work-based” power status system to a “premise-based” system, with premise
3 being the Company’s term for a customer’s home or business location. The
4 Company’s “work-based” system aggregates outage data from the AMI network,
5 input from field crews, and customer calls, and couples this data with the electrical
6 system equipment hierarchy to determine outages at a circuit level. The work-based
7 system does not focus on tracking and monitoring individual customer outages.
8 Creation of a “premise-based” system allows the Company to leverage its AMI
9 infrastructure to monitor individual premise outage data and restoration status, and
10 provide power status and notifications at the customer level. This significantly
11 enhances the relevance and quality of the information and communications
12 provided to customers and improves the customer Outage experience.

13

14 There are six technical components that form the landscape of systems necessary
15 to create the Company’s premise-based system, some that already existed, some
16 that existed but needed to be modified, and some that were completely new:

17

- 18 1. Outage Management System (OMS) – Existing system that processes outages
19 with work-based calculations, using field crew job and equipment data.
- 20 2. AMI – The Company’s Automated Metering Infrastructure (AMI), which
21 supplies voltage, Power Outage Notifications (PONs), and Power Restoration
22 Notifications (PRNs) into Premise Power Stats (PPS—see below) for processing
23 premise-based calculations.

Line
No.

- 1 3. ESRI's ArcGIS – Maintains the equipment hierarchy for the electric grid and
2 uses the hierarchy to map equipment outages to the customers attached to that
3 equipment.
4 4. Event Hub – A new system that streams the outage events from OMS into the
5 new PPS system.
6 5. Premise Power Status (PPS) – A new system that translates work-based outage
7 information from OMS and the AMI meter data into premise-based outage
8 information.
9 6. “Where is My Order” (WISMO) – The Company’s order tracking system, which
10 for Outages integrates information from PPS to allow for tracking of individual
11 customer outages, and to trigger the appropriate notifications to customers.

12

13 **Q65. Can you provide an update on the amount of capital the Company has**
14 **invested, and is planning to invest, in its Error Free Communications (EFC) –**
15 **Outage Status initiative?**

16 A65. Yes. The Company in its DTE Electric U-21297 rate filing, requested recovery of
17 \$35.9 million in 2021-2024 capital to support the modification of the above systems
18 to support the EFC Outage Status initiative, of which \$29.7 million was approved
19 by the Commission in its final order in that case. The Company is now forecasting
20 to spend a total of \$50.0 million in total capital from 2022-2025, which excludes
21 \$2.4 million in 2021 capital previously requested and approved for recovery in U-
22 21297. Exhibit A-24, Schedule N7 provides a complete breakdown of how the total
23 \$50.0 million in capital is being allocated across the back end “Core” systems, and
24 front end “Customer-Facing” systems, including the total amount of capital being
25 invested in each system component or workstream, and the portion of the total

Line
No.

1 capital that was previously approved for recovery by the Commission in its final
2 order in Case No. U-21297. Additional project details are in Exhibit A-24 Schedule
3 N3.1 on Lines 30-32.

4
5 **Q66. How much total capital is allocated to the Core systems to support the EFC –**
6 **Outage Status initiatives?**

7 A66. The Company is investing a total of \$14.2 million in the EFC Core systems,
8 consisting of \$8.4 million in 2022 historical period that was approved for recovery
9 by the Commission in its final order in Case No. U-21297, plus an additional \$5.2
10 million in 2023-2024 bridge period capital, and \$0.6 million in 2025 test period
11 capital, which were not previously requested for recovery. A detailed summary of
12 the capital allocated to the Core systems, including those amounts that were
13 previously approved in Case No. U-21297, can be found in Exhibit A-24 Schedule
14 N7, on Pages 1-2.

15

16 **Q67. How much total capital is allocated to the Customer-Facing systems to support**
17 **the EFC – Outage Status initiatives?**

18 A67. The Company is investing a total of \$35.8 million in capital in the Customer-Facing
19 systems to support the EFC – Outage Status initiatives, which consists of \$14.9
20 million in 2022 historical period capital, and \$20.9 million in 2023-2024 bridge
21 period capital. Of the total \$35.8 million in capital, \$19.0 million was previously
22 approved for recovery by the Commission in its final order in Case No. U-21297,
23 including \$7.0 million in 2022 historical capital, and \$11.9 million in 2023-2024
24 bridge period capital. The \$35.8 million also includes the \$6.3 million in 2022
25 capital allocated to the enhancement of the Outage digital solutions, as described in

Line
No.

1 Part 4 of my testimony. A detailed summary of the capital allocated to the
2 Customer-Facing systems, including those amounts that were previously approved
3 in Case No. U-21297, can be found in Exhibit A-24 Schedule N7, on Pages 3-4.
4

5 **Q68. To-date, what improvements in Outage metrics have been realized through**
6 **the Company's investments in its EFC – Outage Status initiative?**

7 A68. In addition to Outage call volume reductions enabled by the \$6.3 million in 2022
8 EFC – Outage Status initiative capital, which was allocated to the enhancement of
9 the Outage digital solutions as described in Part 4 of my testimony, the Company
10 has realized improvements in 1) the timeliness and accuracy of its outage
11 restoration communications, 2) the timeliness and accuracy of its restoration
12 estimates, and 3) the percentage of successfully delivered outage notifications. I
13 am providing a summary of each of these realized improvements in the pages that
14 follow.
15

16 Power Restoration Accuracy and Timeliness

17 Prior to the implementation of EFC – Outage Status initiative, the customer's power
18 status was tied to the job status, which was overall 94% accurate, but with a range
19 between 80% to 94% during high impact and storm days. Because the power status
20 was not premise-based, the Company could think the customer's power was
21 restored, and communicated this status to the customer, when, in fact, the customer
22 was not restored.
23

24 With the implementation of EFC, where the customer's power status is based on
25 AMI meter data, the Company has consistently achieved a 99% accuracy rate for

Line
No.

the customer's power status. However, timeliness of identifying the customer's power status could be delayed with the use of AMI data, so a new metric was developed to ensure timely delivery of power status updates – Restoration Communication within 1-hour. In 2023, 41.5% of customers who were restored received confirmation of their restoration within 1-hour, which the Company is forecasting to increase to 65% in 2024, while maintaining 99% Power Restoration Accuracy, and for which the Company has established a long-term target of 90%.

First Estimate Accuracy

One of the most significant drivers of customer dissatisfaction during an outage is the lack of an accurate restoration estimate. As such, one of the key elements of the EFC – Outage Status initiatives is to improve the timeliness and accuracy of the first Estimate Time of Restoration (ETR) that is delivered to the customers. Our leading metric, First Estimate Accuracy, measures the percent of customers that received a single and accurate estimated restoration time (ETR). The Company measures First Estimate Accuracy based on the restoration estimate information provided to our customers. In Non-Storm conditions, customers receive a day and time estimate, while in Storm conditions customers receive a day-level estimate. During a storm, an estimate is accurate if the customer receives a single estimate communication and is restored the same day as the day provided in the estimate. The Company defines First Estimate Accuracy more stringently during a Non-Storm day, as the customer must receive a single estimate and be restored no earlier than 3 hours prior and no later than 10 minutes past the estimate communicated.¹ Through its EFC investments, the Company has made steady improvement in this

¹ Criteria for non-storm Blue Sky first estimate accuracy; it would be no earlier than 8 hours prior and no later than 10 minutes past the estimate communicated for non-storm Gray Sky first estimate accuracy.

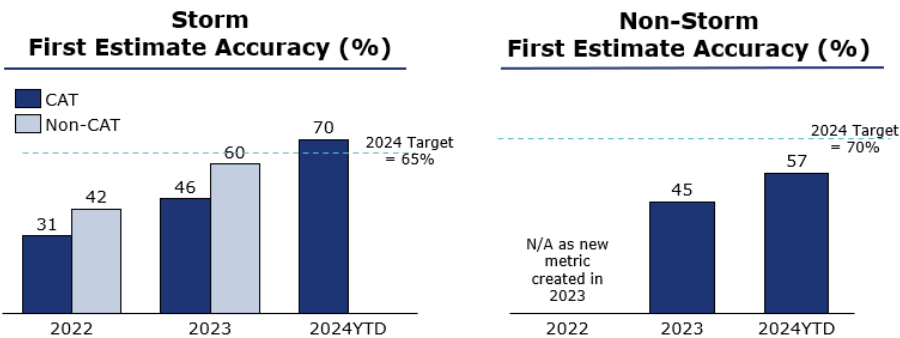
Line
No.

1 metric, achieving the highest catastrophic storm accuracy rate to date in the January
2 2024 CAT storm (Figure 9).

3

4

Figure 9 - Improvement in First Estimate Accuracy



5

6 As seen in Figure 9, we have improved our first estimate accuracy between 2022
7 and 2023 by 48% for catastrophic storms (CAT) from 31% to 46%, and by 43% for
8 non-catastrophic storms (Non-CAT) from 42% to 60%. Additionally, during the
9 January 2024 CAT storm, we performed at 70%, which is above our 2024 Target
10 of 65% for all storms. Similarly, the Company has realized improvements in
11 estimate accuracy for Non-CAT storms, which has increased from 45% in 2023, to
12 57% in 2024. I would note here that because the Company changed the way we
13 define Non-CAT estimate accuracy in 2023, there is no comparative data for 2022
14 performance. Long-term, the Company is targeting 95% First Estimate Accuracy
15 during all storms, and is targeting delivery of those estimates within 4-hours of the
16 storm weather clearing, and within 1-hour during non-storms.

17

18 Additionally, we have improved our estimate delivery timeliness—the amount of
19 time between the weather clearing the service territory and the time outage-specific

Line
No.

1 estimates are delivered to customers. Based on all process improvements, our
2 timeliness has dramatically improved for both CAT and Non-CAT Storms. For
3 Non-CAT storms, we are delivering estimates on average within 5.5 hours after
4 weather has cleared, compared to 16-24 hours before the standard processes were
5 developed. For CAT storms, we are providing estimates on average within 10 hours
6 after the weather has cleared, as compared to 24-36 hours before the standard
7 processes were developed.

8
9 Outage Notification Delivery

10 Historically, only 45% of customers with reported outages successfully received
11 the expected outage status notifications, which includes confirmation of their
12 outage, global restoration estimates, their personal restoration estimates, updates on
13 the status of their outage (e.g., crew assigned, damage being assessed), and their
14 power restored status. With its investments in EFC, the Company has increased this
15 percentage to 70% in 2022 and 88% in 2023, and is forecasting to increase this
16 percentage further to 92% in 2024, with a long-term target of 95%.

17
18 **Q69. Can you describe what additional Core system enhancements beyond the**
19 **original project scope, are being enabled by the Company's incremental**
20 **investments in the EFC – Outage Status initiative?**

21 A69. Yes. The Company has identified and is investing \$5.8 million in incremental
22 2023-2025 capital to address emergent defects that emerged as a result of the 2023
23 ADMS implementation and to further enhance the PPS system, further improve
24 restoration estimate accuracy, and to enhance outage tracking and reporting
25 capabilities. This incremental capital is included in Exhibit A-24 Schedule N7, Page

Line
No.

1 1, Lines 1, 2, 4, 6, and 7. I describe these enhancements, and their expected
2 outcomes and benefits, in the remainder of my response to this question.

3

4 PPS Enhancements

5 The Company is investing \$2.3 million in 2023 and 2024 bridge period, and \$0.3
6 million in 2025 test period, capital to further enhance PPS and its interfaces with
7 the AMI system, ADMS, and WISMO. In 2023, these enhancements allowed for
8 the implementation of system enhancements to ensure that the number of customer
9 outages align across all systems such as the outage map, internal outage dashboards,
10 and website outage totals. In 2024 and 2025, we are adding logic to our systems to
11 allow the Outage Management System (in ADMS) time to process outages before
12 we send communication to customers. This will prevent us from erroneously
13 sending pre-mature estimate communications and/or inaccurate power status
14 notifications. This will also help us reduce the number of power status unknown
15 notifications. These notifications are sent when we cannot reach the customers'
16 meters and are unable to determine whether they have power. This \$2.6 million in
17 incremental capital is included in the total Core system investments, which is
18 reflected in the EFC Exhibit A-24 Schedule N7, on Page 1, Columns c through e,
19 Lines 1, 2, and 4.

20

21 Restoration Estimate Timeliness and Accuracy

22 The Company is investing \$1.1 million in the 2023 and 2024 bridge period, and
23 \$0.3 million in the 2025 test period, capital in its Restoration Estimate initiative,
24 which leverages a standardization of processes and machine learning models to
25 achieve its long-term estimate accuracy goals and objectives. This \$1.4 million in

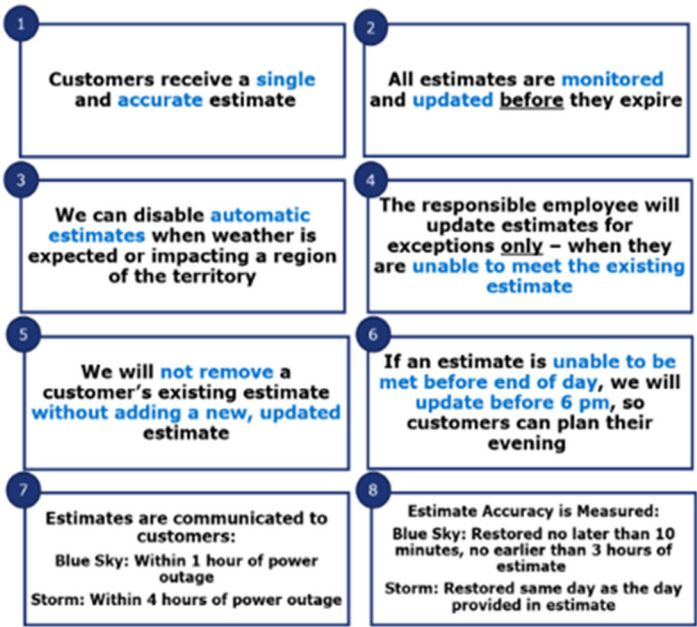
Line
No.

1 incremental capital is included in the total Core system investments, which is
2 reflected in the EFC Exhibit A-24 Schedule N7, on Page 1, Columns c through e,
3 Line 6.

4
5 There are eight defining guiding principles (Figure 10), which have informed the
6 creation of seven Restoration Estimate workstreams (Figure 11), two of which have
7 been completed, that support the continuous improvement of restoration estimates
8 to accelerate achievement of the Company's long-term 95% First Estimate
9 Accuracy target, and the timeliness by which estimates are communicated to
10 customers.

11

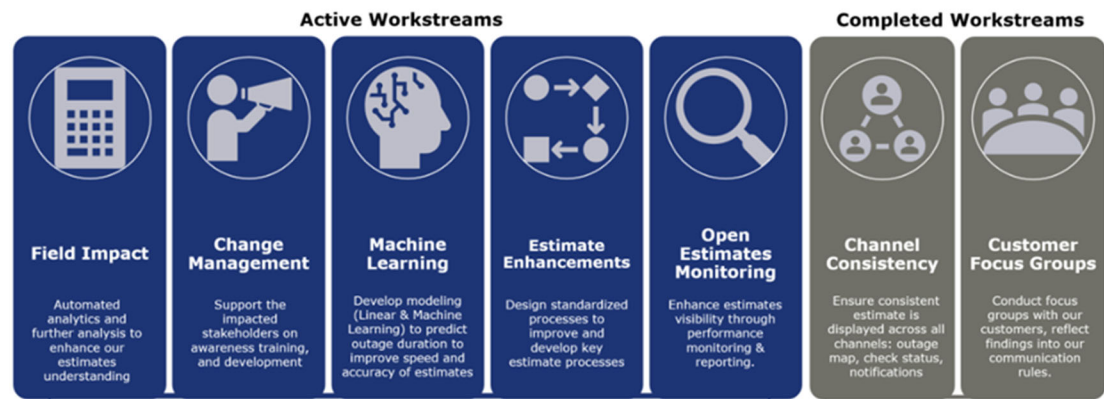
12 **Figure 10 - Restoration Estimate Guiding Principles**



13

Line
No.

1

Figure 11 - Restoration Estimates Initiative - Workstreams

2

3 During non-storm outages, our outage management system generates an estimate
 4 based on an algorithm and sends it within 1 hour to our customers. And while we
 5 have improved First Estimate Accuracy significantly in 2023 (Figure 9), the
 6 continued use of a manual process during storms to generate restoration estimates
 7 means that many customers go for prolonged periods of time without an estimate,
 8 especially during CAT storms.

9

10 To reduce the amount of time required to provide customers a restoration estimate
 11 during storms, a team of data scientists has developed several versions of a
 12 restoration estimate machine learning model and are in the process of validating
 13 them against historical storm data. Once fully developed, the machine learning
 14 model will improve the timeliness of delivering storm estimates by being able to
 15 process a significant volume of historical data, such as the number of customers
 16 out, location, weather, and other environmental factors, without human intervention
 17 to generate an estimate. The chosen model will be used in the summer of 2024 to
 18 generate restoration estimates alongside our existing manual method to gauge the

Line
No.

1 level of improvement and its accuracy. Once the accuracy of the model is
2 established, we will integrate it with the outage management system. Peers with
3 estimate models have spent several years refining their models. The model itself
4 will require a small team of data scientists to continue to train and refine it year
5 after year.

6

7 Outage Tracking and Reporting

8 The Company is investing \$1.8 million in 2024 bridge period capital to enhance its
9 outage monitoring, reporting and analytics capabilities. This incremental capital is
10 included in the total Core system investments, which is reflected in the EFC Exhibit
11 A-24 Schedule N7, on Page 1, Column d, Line 7.

12

13 Prior to the EFC – Outage Status initiative, we did not have one central location to
14 monitor customer outages and the related customer experience during an outage.
15 The systems available allowed us to monitor our job completion progress on outage
16 restoration, but we had no way of monitoring what our customers were
17 experiencing. For example, we did not have a robust or highly accurate method of
18 knowing how many, and which, customers were without power, if they had
19 received restoration estimates, and if those estimates were about to expire.
20 Furthermore, the Company had no visibility into the status of outage notifications
21 sent or received by our customers due to the issue of a legacy communication
22 platform that was not able to consistently and dependably handle the high volume
23 of communications required to be sent, nor provide an accurate record of what was
24 the exact communication sent and make it available in all our customer channels so
25 that customers are not provided with different information. For example, during

Line
No.

1 several of the 2021 storms, we found there were performance problems causing the
2 system to stop sending notifications, a situation for which the Company had no
3 visibility of until hours later. Therefore, customers did not receive proactive
4 information regarding their power status.

5
6 In August of 2022, the Company created new storm dashboards that allow for the
7 monitoring of the customer experience during power outages, including real-time
8 monitoring of the number of customers out, the number of customers restored, those
9 without outage restoration estimates, and customers with expiring estimates. These
10 dashboards provided the Company the visibility required during the heavy 2023
11 storm activity to improve the information provided to customers during both storm
12 and non-storm outages. The dashboards also allow us to monitor the success of
13 delivering outbound outage notifications.

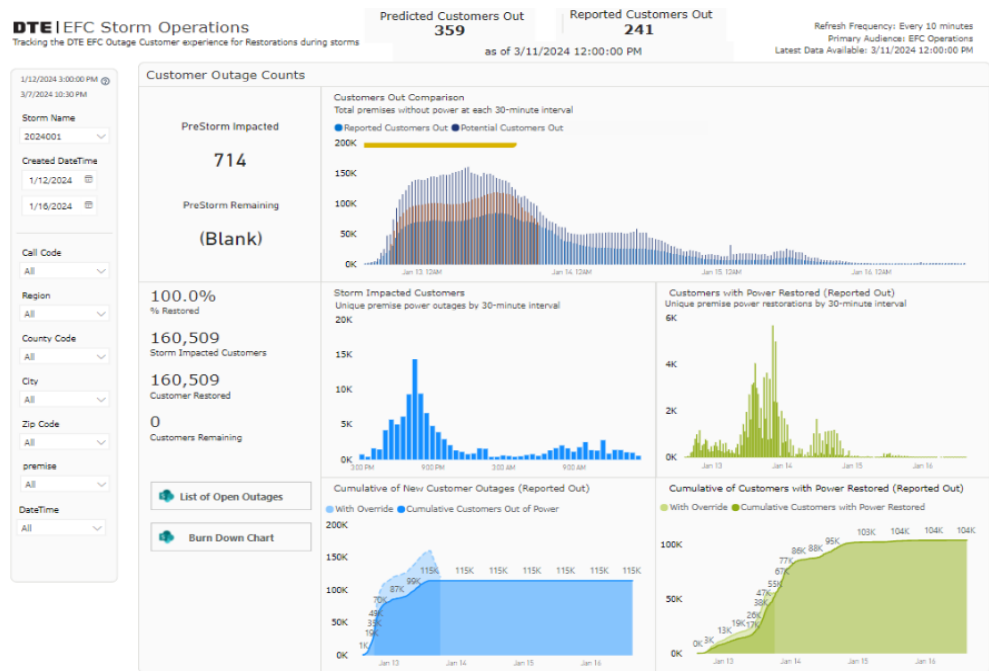
14
15 Lessons learned from the use of these dashboards in 2023 informed opportunities
16 for enhancements in 2024 that will allow the Company to be more proactive and
17 aware during a storm, allowing it to better prioritize its restoration and
18 communication efforts. Examples of the 2023 enhanced dashboards are in Figures
19 12 and 13 below.

20

Line
No.

1

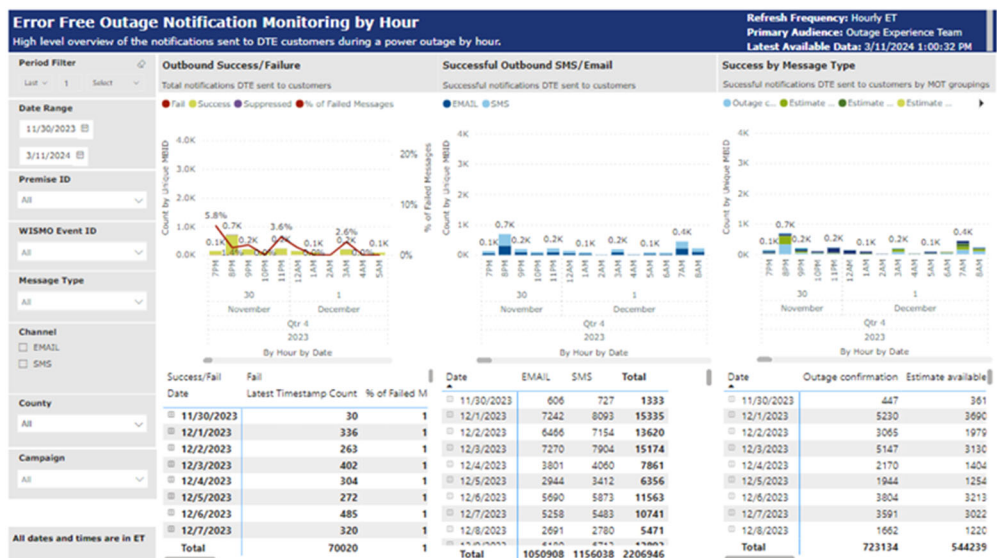
Figure 12 - Customer Outage Status Dashboard



2

3

Figure 13 - Customer Outage Notifications Dashboard



4

Line
No.

1 The data and visibility provided by these dashboards allows Company employees
2 to delve deeper into analyzing and understanding the impact of downstream meter
3 issues on the effectiveness of our customer outage communications. For several
4 reasons, such as the battery life remaining in the AMI meter before it powers down
5 or drops in the relay of information across the meters and routers in the mesh
6 network, the performance of AMI meters communicating a power outage within 30
7 minutes was at 35% in 2023, and the percent of meters with “Power Unknown”
8 status after restoration, which relies on the PRNs successfully reaching the
9 Company, was at 17%.

10

11 The EFC Reporting Team has been analyzing the Power Outage notifications
12 (PONs) and Power Restoration Notifications (PRNs) from the AMI meters to
13 identify opportunities to improve the accuracy and timeliness of the Company’s
14 outage notifications and are pursuing 2024 capital investments that will increase
15 the percent of meters communicating within 30 minutes to 52%, and will reduce
16 the percent of meters with Power Unknown status to 5%.

17

18 **Q70. Can you describe what additional Customer-Facing system enhancements,**
19 **beyond the original project scope, are being enabled by the Company’s**
20 **incremental investments in the EFC – Outage Status initiative?**

21 A70. Yes. As previously described, the Company is seeking recovery for an additional
22 \$16.8 million in 2022-2024 EFC capital, beyond what was approved for recovery
23 in U-21297, and which is inclusive of the impact of \$5.2 million in 2022 EFC
24 historical capital that was previously disallowed as part of the Commission’s
25 disallowance in U-21297 of the total \$51.3 million portfolio of digital self-service

Line
No.

1 projects. This incremental capital is included in the total amounts reflected in EFC
2 Exhibit A-24, Schedule N7 on Pages 3-4, and which has been allocated to
3 addressing emerging defects in the Customer-Facing systems that resulted from the
4 2023 ADMS implementation and to enhance the Customer-Facing systems to
5 provide additional benefits to customers. I describe these enhancements in the
6 remainder of my response to this question.

7
8 WISMO and Outage Map

9 The Company is investing \$5.2 million in incremental 2022-2024 capital in
10 WISMO and the Outage Map to remediate defects from the 2023 implementation
11 of ADMS, and to fund improvements in the integration between WISMO, the
12 Outage Map, and ADMS. Improved integration between WISMO and the Outage
13 Map enhances the consistency of data between what is presented in customer
14 outage notifications and what customers see on the Outage Map. This incremental
15 spend also addressed CRM performance issues encountered during the February
16 2023 CAT storms, which were related to outage reporting that was migrated from
17 CRM to WISMO, and enabling the use of WISMO to track outages reported by
18 Police, Fire, or Municipalities, thereby providing for these stakeholders the same
19 proactive monitoring, tracking, and messaging for these outages as for those
20 reported by other customers. Details on costs by year for these system
21 enhancements are in the EFC Exhibit A-24 Schedule N7 on Page 3 Lines 1-3.

22
23 Notifications

24 The Company is investing \$3.0 million in incremental 2022-2024 capital to further
25 enhance the customer outage notifications experience. In 2023, this work included:

Line
No.

1 1) modifying the language and content for 38 outage Email, SMS, and Voice
2 notifications as part of the transition from the prior OMS (InService) to ADMS; 2)
3 eliminating duplicate messages; 3) ensuring proper sequencing of messages and
4 timeliness; and 4) improving the Preference Management Center to accurately
5 capture and use the customers' preferred service and communication channels.

6

7 This incremental investment enhances the Company's ability to proactively reach
8 out to customers who are experiencing an outage. The details of this outreach are
9 provided below, and for which the capital investment details by year can be found
10 in Exhibit A-24 Schedule N7 on Page 3 Lines 4-5.

11

12 1. Notifications to Customers who are "Likely Out" – The Company uses various
13 data points (e.g., AMI, equipment status, customer outage reports, etc.) to
14 predict when a whole circuit or area is without power. While the new premise-
15 based system uses customer AMI data to determine if a customer is without
16 power, the AMI data is not available 100% of the time—such as when a meter
17 has failed to communicate back to the Company for 100% of the impacted
18 customers. To proactively reach out to customers who are very "likely out", the
19 Company is developing the ability to trigger notifications to these customers to
20 let them know that the region in which they live has been impacted by a storm,
21 how many customers are impacted, and that it is believed that they are without
22 power as well, and provide these customers a method (e.g., two-way texting) to
23 confirm their power status.

24 2. Notifications of Planned Outage Communications – The Company is
25 leveraging its premise-based system to improve the timeliness and quality of

Line
No.

1 customer notifications for planned outages. All our work to date has focused
2 on unplanned outages. We still receive feedback from customers that we can do
3 a much better job communicating planned outages.

4

5 Customer Channels

6 The Company is investing \$3.4 million in incremental 2022-2024 bridge period
7 capital to 1) remediate emerging CRM and digital channel defects that occurred
8 after the 2023 launch of ADMS, 2) fund an additional \$1.1 million in 2022 Outage
9 digital self-service solution enhancements, and 3) make ongoing enhancements,
10 including new Outage functionality and features in the Web and Mobile App.

11

12 This effort has included the continuous improvement of the Outage Map, a
13 redesign of the native Outage App functionality, updating the Outage Center and
14 map statistics, the customer checklist (step 2) in the report outage workflow, and
15 the ongoing improvement in streetlight reporting, and the Police and Fire Web
16 portal which includes enhancing the downed power line reporting form, providing
17 additional wire types on which to report a problem, allowing Police and Fire
18 personnel to upload photos for their reported problem, and providing Police and
19 Fire personnel the estimated time of arrival (ETA) of DTE resources.

20

21 In 2024, the enhancements provided to Police and Fire personnel will be expanded
22 to the Company's residential customers, first on the Web and then in the Mobile
23 App.

24

Line
No.

1 Proactive “Status First” Outage communications – The Company is notifying
2 customers that it is aware of their outage and providing those customers with
3 relevant information. This includes messaging customers who are using a digital
4 self-service channel to report their outage. Details on costs by year for these
5 Channel enhancements are in the EFC Exhibit A-24 Schedule N7 on Page 3 Lines
6 6-8. Also, see Exhibit A-24 Schedule N10 for the completed 2022 and 2024 Outage
7 and EFC Channel enhancements.

8

9 **Part 7. Regulatory and Compliance Projects**

10 **Q71. Which Regulatory and Compliance projects will you discuss in this section of**
11 **your testimony?**

12 A71. Regulatory and Compliance investments are non-discretionary investments that
13 must be made to satisfy MPSC requirements and other industry regulations and
14 compliance items the Company must adhere to provide service to its customers.
15 Part 7 of my testimony explains in detail the Company’s non-discretionary
16 investments in the Regulatory and Compliance IT Investment Category, as shown
17 in Lines 1 through 17 of Exhibit A-12, Schedule B5.7.3. The planned costs across
18 the Regulatory and Compliance projects are discussed further below.

19

20 **Q72. What specific projects are included in the Regulatory and Compliance IT**
21 **Investment category?**

22 A72. There are twelve projects classified as Regulatory and Compliance. Eight projects
23 are related to Clean Energy. The remaining four projects include two that are
24 necessary to comply with industry regulations and standards, and two projects that
25 support the implementation of rates per approved MPSC rate case orders.

Line
No.

1

2 **Q73. Please explain why the Company is investing in the Clean Energy projects.**

3 A73. DTE Electric customers are becoming more aware of, and interested in,
4 opportunities to support the growth in renewable energy and reduce or offset their
5 carbon footprint. As such, the Company is investing in seven projects totaling
6 \$22.9 million, consisting of \$1.1 million in historical period, \$7.3 million in 2023-
7 2024 bridge period, and \$14.5 million in 2025 test period capital as shown in
8 Exhibit A-12 Schedule B5.7.3, in the expansion and creation of products and
9 services that allow customers to contribute to a cleaner environment. These
10 investments satisfy the Company's commitments to the MPSC and our customers
11 under the approved renewable energy plans (U-20851 and U-20713). Additionally,
12 there is one project called MIGP Data and Reporting on Line 40 of Exhibit A-12
13 Schedule B5.7.3 that is categorized in the Strategic investment category that is
14 included in this section.

15

16 Each of the MIGP tariffs have been approved by the MPSC for implementation,
17 with the associated capital dollars reflecting the investment necessary to build the
18 required fixed or volumetric charges in the CR&B system, to enroll or reserve
19 customer interest in a specific MIGP program, to update the Company's MIGP
20 Website, or to create supporting internal dashboarding and reporting to enable
21 efficient management of the MIGP programs. I will discuss each project below that
22 the Company is requesting for recovery in the instant case in the order in which
23 they appear in Exhibit A-12 Schedule B5.7.3.

24

25 1. Line 4 – MIGP Customer-Requested Renewable Energy Projects

Line
No.

- 1 2. Line 6 – MIGP Low Income Solar Pilot
- 2 3. Line 7 – MIGP Reservation System for New Enrollments
- 3 4. Line 8 – MIGP Website Update
- 4 5. Line 10 – MIGP Large Customer Prepayment
- 5 6. Line 11 – MIGP Scope 3 Billing and Enrollment
- 6 7. Line 15 – Rider 17: MIGreenPower, Residential and Small
- 7 Commercial & Industrial
- 8 8. Line 40 – MIGP Data and Reporting (Strategic Investment Category)

9

10 **Q74. What is the scope of the MIGP Customer-Requested Renewable Energy**
11 **Projects?**

12 A74. The Company is investing \$2.7 million in 2023-2024 bridge period, and \$5.5
13 million in 2025 test period capital in the MIGP Customer-Requested Renewable
14 Energy Projects. The capital requested in on Line 4 of Exhibit A-12 Schedule
15 B5.7.3 reflects a variance of \$4.6 million less in the 36 months ending December
16 31, 2024, than was approved for cost recovery in U-21297 as the project has been
17 pushed out to 2025 due to a delay in the construction of these projects.

18

19 These projects are unique contracts between a company and DTE to build dedicated
20 renewable assets to offset the customer's electricity use with green energy. The
21 Company has entered into agreements with two uniquely contracted customers to
22 build two dedicated solar parks with 650 MW and 400 MW of capacity,
23 respectively. Similar in scope to many of our MIGP renewable projects, this project
24 will include end-to-end enhancements to the CR&B system that will include billing,
25 reporting, accounting, and provide enrollment functionality for individual

Line
No.

1 customer-requested projects, and any additional updates to fulfill the Company's
2 commitment under these contracts. These unique contracts also require the creation
3 and integration of a new product named "customer-requested solar park" into the
4 CR&B system and will require enhancements and integration with SAP Business
5 Warehouse (BW) and SAP Commerce Cloud. Customers will enroll and be billed
6 based on the generation from these assets when the projects go into service. See
7 Exhibit A-24 N3.1 Line 48 for additional project details.

8

9 **Q75. What is the scope of the MIGP Low Income Solar Pilots project?**

10 A75. The Company is investing \$1.2 million in 2024 bridge period, and \$0.8 million in
11 2025 test period, capital in the MIGP Low Income Solar Pilots project as shown on
12 Line 6 of Exhibit A-12 Schedule B5.7.3. The capital requested reflects a variance
13 of \$1.0 million less in the 36 months ending December 31, 2024, than was approved
14 for cost recovery in U-21297 as the pilot program is taking longer than expected to
15 launch due to funding sources. Because of this, we are not ready to enroll and bill
16 customers for this program.

17

18 The MIGP Low-Income Solar Pilots project provides the IT functionality in the
19 CR&B system to comprehend the Pilot's program parameters and objectives and
20 enroll qualified low-income customers in the program. Additional functionality
21 must also be developed in the system to collect donations that will offset the
22 premium required for providing solar energy-sourced power to enrolled customers.
23 This project will expand MIGP offerings to low-income customers who might not
24 otherwise be able to participate in the program, and by enabling anyone, whether a
25 DTE customer or not, the option to contribute into a low-income renewables fund.

Line
No.

1 The funds from these voluntary contributions would be used in tandem with third-
2 party donations to fully-subsidize MIGP subscriptions for low-income customers.
3 The system capability to offer this program is addressed in the Company's Section
4 61 filing in MPSC Case No. U-20713, where further details of this and all MIGP
5 programs can be found. When this project is put into service customers will enroll
6 and be billed based on the generation from the assets. See Exhibit A-24 N3.1 Line
7 52 for additional project details.

8

9 **Q76. What is the scope of the MIGP Reservation System for New Enrollments**
10 **project?**

11 A76. The company is investing \$1.5 million in 2023 bridge period capital in the MIGP
12 Reservation Systems project as shown on Line 7 in Exhibit A-12 Schedule B5.7.3
13 to allow residential and small business to enroll into a waitlist if the demand for the
14 MIGP Program exceeds the renewable energy generation currently available. From
15 the waitlist, customers will be enrolled into the MIGP program on a first come, first
16 serve basis when capacity becomes available. Similar in scope to many of the
17 MIGP renewable projects, this project will include end-to-end enhancements to the
18 CR&B system for the waitlist functionality and any related reporting and website
19 updates. See Exhibit A-24 Schedule N3.1 Line 53 for additional project details.

20

21 **Q77. What is the purpose of the MIGP Website Update project?**

22 A77. The Company invested \$1.0 million in 2022 historical period capital in MIGP
23 Website Update project as shown on Line 8 of Exhibit A-12 Schedule B5.7.3 which
24 reflects a variance of \$0.2 million more in the 12 months ending December 31,
25 2022, than was approved for cost recovery in U-21297.

Line
No.

1

2

The MIGP Website Update project redesigned and updated the MIGP Website and migrated it to the Cloud platform in line with the Company's cloud strategy and roadmap for all non-core processes and applications. This upgrade improves the customer experience and ease of use through a revamped process for new customer enrollments, providing existing customers with the ability to change their enrollment levels, and offering greater flexibility with guest enrollment and the customer identification process—all of which reduced the complexity of these processes. See Exhibit A-24 Schedule N3.1 Line 57 for additional project details.

3

4

5

6

7

8

9

10

11 **Q78. What is the scope of the MIGP Large Customer Prepayment?**

12

A78. The Company is investing \$1.3 million in 2025 test period capital in the MIGP Large Customer Prepayment project as shown on Line 10 of Exhibit A-12 Schedule B5.7.3 to allow contracted customers the ability to prepay for future renewable energy charges per Section 61 of the Settlement Agreement. Development will include creating a separate renewable energy accounts receivable section on the customer's bill, a new accounting and general ledger system, and data and reporting tools to enable the program. See Exhibit A-24 Schedule N3.1 Line 50 for additional project details.

13

14

15

16

17

18

19

20

21 **Q79. What is the purpose of MIGP Scope 3 Billing and Enrollment project?**

22

A79. The Company is investing \$3.9 million in 2025 test period capital in the MIGP Scope 3 Billing and Enrollment project, as shown on Line 11 of Exhibit A-12 Schedule B5.7.3 to allow for sponsored MIGP enrollment per the Section 61 agreement. Customers will have the ability to incur the renewable energy charges

23

24

25

Line
No.

1 of another customer. For example, a business could elect to be billed for the
2 renewable energy charges of their employees that enroll in the MIGP
3 program. Similar in scope to many of the MIGP renewable projects, this project
4 will include end-to-end enhancements to the CR&B system that will include the
5 required billing, accounting, and reporting functionality. See Exhibit A-24
6 Schedule N3.1 Line 54 for additional project details.

7

8 **Q80. What is the scope of the Rider 17 – MIGreenPower, Residential, Small**
9 **Commercial, and Industrial project?**

10 A80. The Company is investing \$1.9 million in 2023-2024 bridge period and \$3.0 million
11 in 2025 test period capital in the Rider 17 – MIGreenPower, Residential, Small
12 Commercial, and Industrial project. This capital reflects a variance of \$1.9 million
13 less in the 24 months ending December 31, 2024, than was approved for cost
14 recovery in U-21297. This is because the planned work could not start until after
15 the Commission approved the project in November 2023.

16

17 This project replaces the Rider 19 MIGP Large Commercial & Industrial project,
18 as Rider 19 ended on August 19, 2022, and has been merged with Rider 17. The
19 project scope includes CR&B system changes required to create a fixed price
20 offering for large customers and the ability to enroll residential and streetlighting
21 accounts, bill customers, and other enhancements to manage and administer the
22 program. See Exhibit A-24 Schedule N3.1 Line 80 for additional project details.

23

Line
No.

1 **Q81. Is the Company investing in any other projects related to supporting the**
2 **management of the MIGP Programs or to integrate its renewable programs**
3 **with other products and services?**

4 A81. Yes. The Company is also investing \$0.9 million in 2023 bridge period capital in
5 the MIGP Data and Reporting project as shown on Line 40 of Exhibit A-12,
6 Schedule B5.7.3 that will enhance the management of the MIGP programs and
7 integrate the MIGP programs with other products and services into one reporting
8 solution. The capital investment in this project reflects a variance of \$0.7 million
9 less in the 24 months ending December 31, 2024, than was approved for cost
10 recovery in U-21297, because the project being rescheduled due to project
11 reprioritization.

12

13 This solution will allow the Company to efficiently track and manage MIGP
14 enrollments, usage data, and revenue. The current dashboard and reports rely on a
15 manual process of exporting reports from the source system, analyzing the results,
16 and then importing files to view in a dashboard. A more efficient solution would
17 allow a new dashboard to be updated directly from the source system without
18 manual intervention and in real-time. In addition, the existing manual process is
19 becoming unsustainable as the number of MIGP enrollments continue to grow. The
20 upward trend in the volume of data points being processed is contributing to further
21 slowdowns in processing time.

22

23 **Q82. What is the purpose of the Customer Notifications – TCPA Compliance**
24 **project?**

Line
No.

1 A82. The Company is investing \$0.3 million in 2024 bridge period capital for the
2 Customer Notifications – TCPA Compliance project as shown on Line 3 of Exhibit
3 A-12 Schedule B5.7.3 to comply with the Telephone Consumer Protection Act
4 (TCPA), a federal regulation enacted in 1991 that was amended in 2023 to include
5 SMS/text messages sent to a customer. The regulation includes guidelines on what
6 constitutes a marketing communication versus necessary account communication.
7 With our established automated notifications program, we need to enhance
8 reporting to ensure proper monitoring of the quantities and types of notifications
9 sent to the customer to ensure the Company’s TCPA compliance. Fines for non-
10 compliance range from \$500.00 to \$1,500.00 per instance. The Company sends
11 approximately 60 million notifications annually, most of those automated messages
12 are sent in mass to customers requiring tools to monitor these volumes. See Exhibit
13 A-24 Schedule N3.1 Line 24 for additional project details.

14

15 **Q83. What is the purpose of the PCI Compliance project?**

16 A83. To ensure DTE Electric complies with the Payment Card Industry (PCI) Data
17 Security Standards (DSS) established by the credit card industry and audited by a
18 certified PCI Security Assessor.

19

20 **Q84. Why does DTE need to maintain PCI compliance?**

21 A84. In 2019, the Company achieved PCI DSS Compliance. The Company is investing
22 \$0.1 million in 2022 historical period, \$0.3 million in 2022-2023 bridge period,
23 \$0.2 million in 2025 test period capital to maintain PCI DSS compliance to the most
24 recent standards. The 2023-2024 spend was approved for cost recovery in U-21297.
25 See Exhibit A-24 N3.1 Lines 66 and 69 for additional project details.

Line
No.

1

2

35-40% of payments received from customers are made using a credit or debit card.

3

To accept, store, process, and transmit payments and cardholder data, DTE Electric

4

must adhere to PCI DSS. Failure to adhere to PCI DSS could result in the loss of

5

payment certification with our banking partners and would prevent us from being

6

able to accept credit or debit card payments. This project ensures that DTE's

7

Contact Center's telephony and Interactive Voice Response (IVR) systems remain

8

PCI-compliant. Through these Contact Center systems, DTE customers can

9

complete self-service payments over the phone's automated system as well as

10

provide CRs with credit card information to complete their payments.

11

12 **Q85. What is the purpose of the Regulatory Compliance project?**

13

A85. The Company is investing \$0.8 million in 2022 historical period, \$5.6 million in

14

2022-2023 bridge period, and \$2.8 million in 2025 test period capital, for the

15

Regulatory Compliance project as shown on Line 14 of Exhibit A-12, Schedule

16

B5.7.3 to fund ongoing and emerging rate changes required to be implemented in

17

the CR&B system. The 2022-2024 spend was approved for cost recovery in U-

18

21297. See Exhibit A-24 Schedule N3.1 Line 77 for additional project details.

19

20

This project funds CR&B and reporting system changes necessary to comply with

21

the outcome of any MPSC rate orders, to provide funding for emerging regulatory

22

compliance items, and to fund the implementation of new rates and programs as

23

approved by the MPSC.

24

Line
No.

1 In 2022, funding from the Regulatory Compliance project supported the roll-out of
2 the D13 rate as DTE Electric proposed a D13 XL-HLF rate to provide the Company
3 the opportunity to optimize its load base and make incremental contributions to
4 DTE Electric's fixed costs. The D13 rate aimed to provide customers with
5 competitively priced electricity consistent with cost-of-service-based rates to
6 address the changing circumstances of its automotive and other advanced
7 manufacturing customers.

8

9 In 2023, this project, as in prior years, provides a yearly investment that allows
10 DTE to implement IT system changes inclusive of logic and screen changes to the
11 CR&B system for the Agency Website/Online Resource for Energy Assistance
12 Agencies (AGW/ORR) applications, and StreamServe for bill formatting changes
13 to support emergent Regulatory work.

14

15 As a result of a 2023 MPSC ruling, the CR&B system application revised outflow
16 billing determinant calculation for all Rider 18 demand-based rates. The outflow
17 demand will be determined by the average of On-Peak demand during the billing
18 period. Also, for Rider 18 D1.8 customers, the invoice should display the Critical-
19 Peak, Mid-Peak, On-Peak and Off-Peak information under the Current Billing
20 Information section of the bill. Additionally, the redesign of the existing Low
21 Income Self Sufficiency Plan (LSP) will allow for a reduced monthly plan amount
22 developed for each household based on their previous 12-months usage while
23 issuing monthly credit incentives based on household income and consumption.
24 The redesigned LSP program will also change the way arrears forgiveness is issued

Line
No.

1 and introduce plan amount reviews at regular intervals to ensure the customer's
2 budget portion is aligned with their recent consumption pattern.

3
4 In the 2024 bridge period, as described by Company Witness Willis in his testimony
5 related to the Company's proposal for transitioning D1.6 customers to the new
6 D1.11 TOD rate and closing the D1.6 rate, investments from the Regulatory
7 Compliance project will fund the CR&B system changes required to complete the
8 three key elements of this transition.

9
10 Currently, the Low-Income Assistance (LIA) credit is available only to customers
11 taking service on D1.6 – a customer who is otherwise eligible but chooses to take
12 service on a different base rate may not avail themselves of the credit. The transition
13 to Time-of-Day rates provides an opportunity not only to re-align rate design for
14 D1.6 customers, but also to expand their ability to choose their base rate schedule
15 while retaining the LIA credit. The Company anticipates the implementation of this
16 transition will occur during the projected bridge year. Thus, the Company's Exhibit
17 A-16, Schedules F3 and F8 both reflect the continuation of D1.6 into the 2025
18 projected test year given the requirement to continue utilizing the rate for a period
19 of time.

20
21 In addition to the scope previously described, this project also ensures there is
22 sufficient funding for planned and emergent revisions to electric rates, amendments
23 to rate schedules and rules governing the distribution and supply of electric energy,
24 and any other modifications of DTE Electric rates in accordance with MPSC orders.

25

Line
No.

1 **Q86. What is the scope of the Securitization Project?**

2 A86. The Company invested \$0.3 million in 2022 historical period capital in the
3 Securitization project as shown on Line 16 in Exhibit A-12 Schedule B5.7.3 to
4 complete the necessary rate changes in the CR&B system to include two new
5 securitization surcharges for residential, industrial, and commercial customers.
6 DTE filed MPSC Case No. U-21015 requesting MPSC approval to issue
7 securitization bonds and implement a surcharge related to the cost of the
8 Company's retirement of the River Rouge power plant and a surge in tree trimming
9 costs. The Commission granted approval for the securitization of up to \$235.8
10 million in qualified costs on June 23, 2021. See Exhibit A-24 Schedule N3.1 Line
11 81 for additional project details.

12

13 **Part 8. Historical 2022 Project Spend Variance and Other Project Variance**

14 **Q87. How much total Customer IT Portfolio capital did the Company spend in**
15 **2022, and how does it compare to what was approved for recovery in Case No.**
16 **U-21297?**

17 A87. The Company spent \$224.3 million of capital on IT projects in 2022 compared to
18 the \$165.0 million approved by the Commission in Case No U-21297, as shown in
19 Line 18 of Exhibit A-24 Schedule N2, which is \$59.3 million more than was
20 approved.

21

22 **Q88. For projects supported in your testimony in the instant case, what is the**
23 **variance between the capital the Company spent in 2022, and what was**
24 **approved for recovery in Case No. U-21297?**

Line
No.

1 A88. For the projects that I support in my testimony in the instant case, there is a variance
2 of \$21.9 million between the amount of capital that was approved for cost recovery
3 in Case No. U-21297 and capital invested by the Company. This variance is
4 associated with seven projects shown in Exhibit A-24 Schedule N2 and include:
5 Error Free Communications, Bill Management, Customer Relationship and Billing
6 Program Enhancement, Advanced Analytics Use Cases, and three projects whose
7 spend were a sub-set of the \$51.3 million Digital Self-Service Project Portfolio
8 described in U-21297. The specific projects that make up the variance are listed
9 below with references to the corresponding testimony in the sections above and/or
10 in Table 9 below.

Table 9. 2022 Project Variance Explanation

Project	Variance Testimony Reference	Variance Explanation
Error Free Communication - Outage Status	Page MJH-81, Lines 7-16.	In 2022, the Company invested \$7.8 million more than was approved in U-21297 for cost recovery. The additional spend is due to \$0.7 million spent on WISMO and Outage Map system enhancements to fund enhancements to the WISMO and Outage Map interfaces with the core system enhancements, \$0.8 million for updating customer notifications and development of Outage status dashboard reporting, and \$6.3 million on customer channel enhancements for the Web and IVR. Of the \$7.8 million variance in 2022, \$5.2 million funded investments to improve the customer's outage digital experience and was part of the \$51.3 million portfolio of digital self-service projects that was disallowed in the Commission's Final Order in U-21297.
Journey Work Product Transformation Teams	Page MJH-21, Lines 3-5. Page MJH-25, Lines 9-11. Page MJH-29, Lines 10-12.	See testimony reference. The Company invested \$6.7 million in 2022 to fund investments to improve the customer's Collections, MIMO and Outage digital experience and this spend was part of the \$51.3 million portfolio of digital self-service projects that was disallowed in the Commission's Final Order in U-21297.
Bill Management	Page MJH-34, Lines 12-16.	See testimony reference. The Company invested an additional \$3.4 million in the Bill Management tool in 2022 to address identified defects, to continue to enhance the Billing experience, and to incorporate the ability for the tool to effectively analyze and simulate Time-of-Day (TOD) bills, to support the TOD project go-live in March of 2023.
IVR Virtual Assistants	Page MJH-25, Table 5. Page MJH-25, Lines 19-21. Page MJH-26, Lines 1-3.	See testimony reference. The Company invested \$1.3 million (\$1.2 million net of 2023) in 2022 to fund investments in the MIMO Virtual Assistant to improve the customer's MIMO digital experiences and this spend was part of the \$51.3 million portfolio of digital self-service projects that was disallowed in the Commission's Final Order in U-21297.

Line
No.

Project	Variance Testimony Reference	Variance Explanation
Customer Relationship and Billing Program Enhancement	Page MJH-21, Lines 1-3. Page MJH-25, Lines 7-9. Page MJH-33, Lines 7-10. Page MJH-54, Lines 24-25. Page MJH-55, Lines 1-4.	The Company invested \$1.2 million more in 2022 spend composed of the following two reasons: 1) \$0.4 million of the 2022 CR&B spend variance is because this spend was part of the \$51.3 million portfolio of digital self-service projects that was disallowed in the Commission's Final Order in U-21297. See testimony reference. 2) The variance of \$0.8 million more than was approved for recovery in U-21297 was due to additional scope required to support enhancements in the Collection, MIMO and Billing transactions to improve the customer's experience and improve First Contact Resolution (FCR). See testimony reference.
Advanced Analytics AA Use Cases Implementation	N/A	In 2022, the Company invested \$1.1 million more than approved in U-21297 for cost recovery. The Advanced Analytics Use Cases project leverages advanced analytics, machine learning and other data science techniques and technologies in specific use cases to derive greater insight into customer segments, behaviors, and pain points, to understand the drivers of customer satisfaction, and to support reduction in O&M costs and uncollectible expense (UCX) or to capture operational efficiencies that improve the effectiveness of our processes and key transactions. All the 2022 variance is due to the full disallowance of the entire \$4.3 million in 2022-2024 project spend in the Commission's Final Order in U-21297.
Customer Closed Loop Development	Page MJH-63, Lines 8-13.	See testimony reference. The Company invested \$0.3 million in 2022 to fund investments to improve the customer's MIMO and Collection digital experience and this spend was part of the \$51.3 million portfolio of digital self-service projects that was disallowed in the Commission's Final Order in U-21297.

1

2 **Q89. Were there any other projects that had variances that you have not yet**
3 **discussed?**

4 A89. Yes. There are two projects listed below that were not completed in 2022 and 2023
5 and are not planned for completion in 2024 as previously approved for cost
6 recovery in Case No. U-21297.

7

Line
No.

1 1. IVR Natural Language – This project is currently being rescheduled and upon
2 approval of the confirmed project dates, the request for cost recovery will be
3 re-submitted for approval in a future rate case.

4 2. Secure Cloud Payment Provider Migration – This project is currently being
5 rescheduled and upon approval of the confirmed project dates, the request for
6 cost recovery will be re-submitted for approval in a future rate case.

7

8 **Part 9 – Customer Service Operation and Maintenance Expense**

9 **Q90. What work does the Customer Service group perform?**

10 A90. Customer Service is responsible for managing the customer support processes for
11 both DTE Electric and DTE Gas. Customer Service is comprised of operational
12 and customer strategy and insight organizations that are responsible for conducting
13 the work associated with customer transactions, data analytics, arrears reduction,
14 billing, and payment acceptance.

15

16 **Q91. What is the role of Customer Service for DTE Electric?**

17 A91. The Customer Service team supports the delivery of highly satisfying customer
18 experiences and drives improvement where needed. Through continuous
19 improvement, technology is leveraged to meet and anticipate changing customer
20 expectations. This technology includes digital channels for customers to conduct
21 business in the channel of choice and programs that provide added ease and
22 convenience.

23

24 To better assist our employees in making decisions in moments of service and
25 enable service excellence, the Company established the Keys of Service

Line
No.

1 Excellence. These keys are: Safe, Caring, Dependable, and Efficient. All Customer
2 Service activities pass through the Service Keys. Our desired culture is one where
3 all employees have a service mindset and a strong emotional connection to caring
4 for our customers and each other.

5

6 **Q92. What are the two divisions of Customer Service?**

7 A92. Customer Service is made up of Operations and Customer Strategy & Insight.

8

9 **Q93. What departments make up Customer Service Operations and what are their**
10 **functions?**

11 A93. Customer Service Operations consists of the following departments:

12

- 13 • Contact Center Operations
- 14 • Metering, Billing, & Exceptions
- 15 • Revenue Management & Protection (RM&P)
- 16 • Customer Service Operations Support

17

18 Contact Center Operations manages requests for new service, responds to inquiries
19 regarding account information, schedules work requests from customers, and
20 responds to emergency and trouble calls.

21

22 Metering, Billing, and Exceptions is responsible for meter reading, residential and
23 commercial billing, major accounts billing, customer print and delivery, and bill
24 issue resolution. The team is responsible for working and resolving any billing and
25 collection issues that include manual intervention. These items primarily consist of

Line
No.

1 billing exceptions, collections exceptions, bankruptcy, ID fraud probate, and theft
2 work.

3
4 RM&P manages credit policies, administers low-income programs, and accounts
5 receivable collection. RM&P is also responsible for theft investigations,
6 remediation, and determining accountability for unauthorized usage.

7
8 Customer Service Operations Support is responsible for quality and training of
9 Customer Service staff. It also has responsibility for the overall Continuous
10 Improvement efforts of the Customer Service Organization.

11

12 **Q94. What departments make up Customer Strategy and Insight and what are their**
13 **functions?**

14 A94. Customer Strategy and Insight consists of:

15

- 16 • Customer Service Transformation
- 17 • Customer Service Analytics
- 18 • Executive Consumer Affairs Center (ECAC)
- 19 • Digital Experience

20

21 The Customer Service Transformation organization provides system and technical
22 support for the Customer Relationship & Billing (CR&B) system. The System
23 Support group identifies emerging trends in SAP, coordinates business design,
24 manages the translation of business needs to system design, identifies defects, and
25 supports solutions. The Technical Support group are experts in functional design

Line
No.

1 and serve as liaisons to the ITS organization. They conduct unit testing, complete
2 simple configuration, support proof of concept designed, and resolve incident
3 management tickets as applicable. The Customer Service Transformation
4 organization also develops dashboards to visualize transaction completion and
5 other performance metrics.

6

7 Customer Service Analytics is responsible for providing data analytics support to
8 Customer Service, which includes data queries, reports on customer segmentation,
9 and predictive modeling.

10

11 ECAC resolves escalated customer issues that are received from the Michigan
12 Public Service Commission, “I Can Help” (including Media, Government Affairs,
13 Regional Relations, and Employees), Better Business Bureau, the Attorney
14 General, and DTE’s Website. This organization also includes the Customer
15 Insights & Research team that manages all aspects of customer satisfaction
16 measurement and feedback loops to resolve outstanding issues from the customers
17 surveyed. The team also collaborates with internal stakeholders to develop and
18 execute customer-facing research such as online quantitative surveys, qualitative
19 focus groups, and individual interviews that are used to gather customer insights.

20

21 Digital Experience is responsible for creating a customer-focused, consistent,
22 multichannel experience that emphasizes the use of DTE’s self-service channels,
23 including mobile applications, kiosks, the DTE website, and Interactive Voice
24 Response (IVR) to provide excellent and efficient customer service. The team has
25 two components: (1) Transactional Experience, which focuses on customer

Line
No.

1 transactions including policy reviews and process design to mitigate hand offs and
2 customer dissatisfaction and (2) Digital Experience, which focuses on efficient and
3 satisfying methods to complete these transactions.

4

5 **Q95. How are costs allocated between DTE Electric and DTE Gas for Customer**
6 **Service?**

7 A95. Customer Service costs are allocated based on utility-specific data that is
8 representative of the amount of electric- or gas- related work conducted within the
9 organization. The allocations for the current year are based on actual activity data
10 from the previous year. Several costs are allocated based on the number of electric
11 and gas customers.

12

13 Call Center Operations, Customer Service Operations Support, Customer Service
14 Transformation, Digital Experience, and ECAC expenses are allocated based on
15 the number of electric and gas customers. For a customer who is both an electric
16 and a gas customer, that customer is counted as one-half electric and one-half gas.
17 For 2022, 66.2% of these expenses were allocated to DTE Electric.

18

19 Customer Billing expense is allocated between DTE Electric and DTE Gas via two
20 cost allocation drivers. The first driver is based on the number of electric and gas
21 customers and the second, used for Meter Reading expenses, is based on the number
22 of Advanced Metering Infrastructure (AMI) and non-AMI customers. For 2022,
23 66.2% of Customer Billing expense was allocated to DTE Electric based on the
24 number of electric and gas customers. Based on AMI and non-AMI customers, the
25 2022 DTE Electric allocation for Meter Reading Expenses was 9.3%

Line
No.

1 RM&P allocates costs based on the number of accounts in arrears. For 2022, 65.2%
2 of RM&P expense was allocated to DTE Electric.

3

4 **Q96. What was the total DTE Electric O&M cost related to Customer Service for**
5 **the 2022 historical test year?**

6 A96. The total O&M cost related to Customer Service for the adjusted 2022 historical
7 test year is \$112.4 million. A detailed breakdown of the 2022 historical test year
8 actual O&M expense adjusted by rate case eliminations, normalization
9 adjustments, inflation, and other known and measurable adjustments is provided in
10 Exhibit A-13, Schedule C5.7.

11

12 **Q97. What expenses are included in the 2022 total O&M costs provided on Exhibit**
13 **A-13, Schedule C5.7?**

14 A97. The components that make up the \$112.4 million O&M expense:

15

- 16 • Customer Accounts Expenses \$94.7 million
- 17 • Customer Service and Informational Expenses \$25.4 million
- 18 • Less Reclass to Marketing Exhibit \$7.6 million

19

20 **Q98. What adjustments were made to the historical test period?**

21 A98. The following adjustments are shown on Exhibit A-13, Schedule C5.7:

22

- 23 • Column (c) Line 20 reflects a \$7.6 million reclassification to Marketing
- 24 Expenses, sponsored by Company Witness Bennett on Exhibit A-13
- 25 Schedule C5.9 Line 5.

Line
No.

- 1 • Column (d) Line 19 eliminates \$173 million in expenses related to the
- 2 Energy Waste Reduction Program (EWR). O&M expenses for the
- 3 Company's EWR program are recorded in FERC accounts 905, 907, 908
- 4 and 909. Since these costs have their own distinct recovery surcharges and
- 5 are reconciled in separate MPSC proceedings, I have eliminated them from
- 6 O&M. These eliminations are shown in Column (d) of Exhibit A-13,
- 7 Schedule C5.7.
- 8 • Column (e) Line 19 eliminates \$23.9 million for the Low-Income Energy
- 9 Assistance Fund (LIEAF). The LIEAF expense being eliminated is
- 10 associated with the remittance of the revenue collected through the LIEAF
- 11 surcharge. Funds collected through the surcharge (a state-mandated charge)
- 12 are remitted directly to the state and help provide heating assistance to low-
- 13 income customers.

14

15 **Q99. What are the primary activities included in the Customer Accounts Expenses**
16 **category totaling \$95.7 million?**

17 A99. The Customer Accounts Expenses category includes Supervision \$2.0 million,
18 Meter Reading \$2.1 million, Customer Records and Collection \$76.9 million,
19 Merchant Fees \$11.8 million as supported by Company Witness Peterson,
20 Customer 360 Amortization \$2.8 million as supported by Company Witness
21 Uzenski, and ACPP/Time of Day Reg Asset Amortization for \$0.1 million.

22

23 **Q100. What makes up the \$2.0 million Supervision expense?**

24 A100. Supervision expenses allocated to FERC 901 include Customer Service senior
25 leadership and support staff.

Line
No.

1 **Q101. What activities make up the \$2.1 million in Meter Reading?**

2 A101. The Company utilizes external vendors to manually read meters not converted to
3 AMI meters and AMI opt-out meters. These costs also include other back-office
4 support such as route coordinators and personnel who are responsible for
5 monitoring the adherence of the contract terms by the service provider, handling
6 the weekly service provider billing, and analyzing meter reading complaints.

7
8 **Q102. What organizations contribute to the \$76.9 million of customer records and**
9 **collection expenses?**

10 A102. The organizations included in Customer Records and Collections are the following:

11

- 12 • Contact Center Operations
- 13 • Revenue Management & Protection (RM&P)
- 14 • Metering, Billing, and Exceptions
- 15 • Customer Experience
- 16 • Customer Service Operations Support

17

18 **Q103. What activities are comprised in the Contact Center Operations organization?**

19 A103. Much of the activity in the Contact Center Operations organization is customer-
20 facing. Handling over four million calls annually, the organization is the front line
21 for customer resolution. Support staff within the Contact Center Operations
22 organization handle routing for both internal and external calls, operational support,
23 and the telecom IVR technology associated with the Company's toll-free number.

24

25 **Q104. What has been the focus of the Contact Center Operations organization?**

Line
No.

1 A104. The focus of the Contact Center Operations is streamlining the customer experience
2 and includes:

3

4 • Incorporating CR represented web chats across MIMO and billing
5 transactions to provide assistance to customers.

6 • Workforce automations that provide real-time CR productive status and
7 schedule adherence to optimize off-phone activities.

8 • Continued closed-loop enhancements to provide efficient assistance to
9 customers during a single call interaction.

10

11 These efforts are supported by projects outlined in the capital section of my
12 testimony.

13

14 **Q105. What components make up the RM&P organization?**

15 A105. There are four major components that make up the RM&P organization:

16

17 • Internal & External Collections

18 • Field Operations

19 • Energy Advocacy Group (formerly Advocacy & Customer Offices)

20 • Strategy & Reporting and RM&P Staff

21

22 **Q106. What are the activities of Internal and External Collections?**

23 A106. The Internal and External Collections group uses external collection agencies to
24 perform collection on outstanding arrears to reduce uncollectible expense.

25 Effective use of this partnership allows the Company to mitigate the impact of

Line
No.

1 uncollectible expense related to customers who have been disconnected. Company
2 Witness Johnson provides more detail on uncollectible expense in her direct
3 testimony.

4
5 **Q107. What are the activities of the RM&P's Field Operations group?**

6 A107. RM&P's Field group performs theft investigations and non-pay manual
7 disconnects. Field Operations is responsible for driving operational efficiencies
8 through accurate and timely shutoffs. DTE is committed to protecting the safety
9 of our communities throughout our service territory. Effective management of
10 energy theft minimizes lost revenue while safeguarding legitimate customers from
11 bearing the cost of utility theft. The illegal connection activity associated with theft
12 also exposes customers and the public in general to potential life-threatening
13 hazards.

14
15 **Q108. What activities comprise the Energy Advocacy Group (formerly Advocacy &
16 Customer Offices)**

17 A108. The Energy Advocacy Group (EAG) focuses on some of the Company's most
18 vulnerable customers. This includes supporting our Low-Income Self-sufficiency
19 Plan (LSP) customers and working with partner agencies. In 2022, the EAG team
20 handled over 160,000 calls and completed 67,090 low-income validations and
21 approximately 3,574 medical exception hold requests. EAG assists all customers,
22 but with a focus on our most vulnerable. Customer Assistance Days (CADs) is one
23 way in which assistance is provided. In 2022, the EAG team continued to assist
24 households through virtual CADs including an In-Person DTE Customer Resource
25 Fair hosted in partnership with THAW during its 13th Annual Week of Warmth.

Line
No.

1 These events are often based on partnership with local agencies and organizations
2 to provide case management solutions, energy efficiency education, and utility
3 payment assistance to customers in need throughout the year.

4

5 **Q109. What are the activities for the Strategy and Reporting RM&P staff?**

6 A109. The Strategy and Reporting RM&P staff is responsible for creating and maintaining
7 the customer service billing and payment plan policies. In addition, the team is
8 responsible for compliance, supporting metrics, and data analysis as they pertain to
9 these policies.

10

11 **Q110. What are the activities of the Metering, Billing, and Exceptions group?**

12 A110. The Metering, Billing, and Exceptions group is responsible for obtaining manual
13 reads on DTE's meters; billing activities for residential, small commercial, large
14 commercial and industrial customers; print and delivery for customer-facing
15 mailings including bills; exceptions management including billing investigations,
16 bankruptcy filings, probate filings, ID fraud and theft billing; and billing programs
17 such as Budget Wise Bill (BWB) and eBill.

18

19 **Q111. What activities make up Customer Experience?**

20 A111. Customer Experience is responsible for developing modern technologies for
21 customers to interact with the Company through self-service channels such as the
22 internet and mobile applications. The self-service applications include electronic
23 billing, payment, move ins/move outs, outage reporting, estimate communications
24 and status updates, and others.

25

Line
No.

1 **Q112. What work activities comprise the Customer Service Operations Support**
2 **organization?**

3 A112. Customer Service Operations Support organization has established, documented,
4 and implemented a Quality Management System (QMS) which includes processes
5 and procedures associated with Customer Service. Documented processes are
6 maintained and continually improved to ensure that the QMS achieves its intended
7 results. Over 1,000 Customer Service documented processes are included in the
8 QMS which includes but are not limited to: Call handling, collections, digital
9 experience, billing, and quality assurance.

10

11 QMS includes a structured quality approach to ensure processes are followed,
12 continually improved, and operational stability is maintained. Tools used to identify
13 risk and opportunities may include but are not limited to: Process Failure Mode
14 Effects Analysis (PFMEA), Strengths Weaknesses Opportunities Threats (SWOT),
15 Corrective Action Program (CAR), and Journey Mapping.

16

17 Additionally, the organization conducts training of new Customer Service
18 employees, provides ongoing training to existing employees, and provides quality
19 assurance for customer calls using advanced call monitoring and recording
20 technology. These and many other key activities drive defect prevention and
21 increase customer satisfaction. In 2021, as a result of driving continuous
22 improvement across the Customer Service organization, DTE received the world's
23 first ISO 9001:2015 certification awarded to a customer service organization. The
24 certification, from the International Organization for Standardization (ISO),
25 recognizes that the Company's employees are highly focused, motivated, and

Line
No.

1 engaged in providing quality service for their customers. Customer Service will
2 champion recertification in 2024.

3

4 **Q113. What is included in the Customer Collection – Merchant Fees?**

5 A113. Refer to Company Witness Bennett ‘s testimony in the instant case for details on
6 merchant fees.

7

8 **Q114. What are the primary components of the Customer Service and Informational**
9 **Expenses category totaling \$24.4 million?**

10 A114. The Customer Service and Informational Expenses category is primarily made up
11 of activities related to Supervision \$3.8 million, Customer Assistance \$15.0
12 million, and Miscellaneous Customer Service and Informational Expenses \$5.6
13 million.

14

15 **Q115. What is included in the \$3.8 million in Supervision expenses?**

16 A115. Most of the costs are labor for regulated marketing activities including internal and
17 external stakeholders.

18

19 **Q116. What are the primary components that comprise the \$15.0 million in**
20 **Customer Assistance Expenses?**

21 A116. Excluding the Energy Waste Reduction Program and LIEAF offsets mentioned
22 above, there are four major components that make up the \$15.0 million in expense:

23

- 24 • Customer Service Groups
- 25 • Regulated Marketing (sponsored by Company Witness Bennet)

Line
No.

1 • Distribution Operations

2 • Public Affairs

3

4 **Q117. What are the activities of the Customer Service Groups (Strategy & Insight)?**

5 A117. The Customer Service Groups drive strategy and continuous improvement
6 processes including system and process enhancements to improve the customer
7 experience. Activities such as benchmarking of best-in-class utilities and other
8 world-class customer service organizations allow us to ensure we are aware of
9 changing customer expectations and how others are responding to it. Root cause
10 analysis activities have been critical to improving the Company's internal service,
11 resulting in improved employee and customer engagement. The Customer Service
12 Groups identify key customer "blue chip" priorities such as reliability, transaction
13 excellence in the form of personalized, simple, transparent, and easy to navigate
14 customer interactions, and contact resolution to drive the development of
15 sustainable improvements to customer satisfaction and address performance gaps.

16

17 **Q118. What activities comprise the Distribution Operations team?**

18 A118. The activities performed by this team include issue resolution, enrollment
19 management, and metering services including storm restoration. The team is
20 comprised of a contact center and a team of billing analysts.

21

22 **Q119. What are the activities of Public Affairs?**

23 A119. Public Affairs identifies communities and customers in need of DTE programs and
24 services and provides a community forum to connect low-income customers with
25 resources and several types of energy assistance offered through the Company.

Line
No.

1 Customers who qualify can sign up for the LSP or receive emergency relief
2 assistance, sometimes on the spot, given agencies are on site with us at these
3 community forums. At these forums, we also educate customers on the programs
4 we offer, such as Home Energy Consultations and EWR assistance. In addition to
5 these formal programs, the organization supports health and human service
6 agencies such as United Way and Salvation Army that distribute assistance to
7 vulnerable Michigan residents.

8

9 Our support to established community partners helps them provide facilities,
10 volunteers, transportation, and other resources to achieve additional outreach to
11 customers living under challenging circumstances. Many of the Company's
12 employees advocate for customer assistance when they volunteer to support
13 Michigan-based non-profits through the Company's enterprise-wide volunteerism
14 program Care Force, which is run through Public Affairs.

15

16 **Q120. What are the primary activities that comprise the \$5.6 million of**
17 **Miscellaneous Customer Service and Informational Expenses?**

18 A120. These activities include responsibilities of the Customer Service Transformations,
19 Digital Experience, and Data Analytics teams. The Digital Experience department
20 works closely with other departments across the organization to ensure that all
21 digital touchpoints are fully integrated with DTE's business systems, providing a
22 seamless end-to-end customer experience. Additionally, the department
23 collaborates with external partners and vendors to implement innovative
24 technologies and innovations to further enhance the digital experience for
25 customers. In addition to what is mentioned above, activities include the

Line
No.

1 implementation and sustainment of the Robotic Process Automation (RPA) team
2 and automation in the Customer Service organization (Closed Loop activities).
3

4 **Q121. What is the total amount of Customer Service O&M that DTE Electric seeks**
5 **to recover in rates for the projected test period?**

6 A121. DTE Electric seeks to recover \$118.6 million (Exhibit A-13, Schedule C5.7
7 Column (m), Line 21) in Customer Service O&M in the projected test period.
8 Exhibit A-13, Schedule C5.7 provides a detailed breakdown of the projected test
9 period O&M expenses that the Company is requesting in this case.
10

11 **Q122. What costs are included in the \$118.6 million of O&M expense?**

12 A122. In addition to the 2022 costs described in my testimony regarding the historical test
13 period, the Company has included the following changes: 1) inflation adjustments
14 in 2023 for \$3.1 million, 2024 for \$2.9 million, and 2025 for \$3.0 million; 2) a
15 known and measurable adjustment of merchant fees of \$0.5 million supported by
16 Witness Bennett (Line 6, Column k); 3) a reduction in Customer Records and
17 Collection Expenses of \$6.4 million (Line 5, Column k); and 4) ACPP / Time of
18 Use Reg Asset Amortization of \$3.0 million (Line 8, Column k).
19

20 **Q123. How did you calculate the \$9.1 million for inflation?**

21 A123. Projected inflation for 2023, 2024, and 2025 O&M expenses was derived by
22 applying the inflation factors supported by Company Witness Uzenski to the
23 adjusted 2022 historical test period amounts (Column (g)).
24

Line
No.

1 **Q124. What represents the \$6.4 million decrease in Customer Records and Collection**
2 **Expenses in Column (k)?**

3 A124. The \$6.4 million decrease is the forecasted savings from expected lower call
4 volumes enabled by Digital investments.

5
6 **Q125. Can you please explain the estimated \$3.0 million Customer Service regulatory**
7 **asset impacts of the Company's Time of Day (TOD) Full Implementation?**

8 A125. As explained by Company Witness Uzenski, the Company deferred certain costs
9 related to the implementation of its Advanced Customer Pricing Pilot and Time of
10 Day rate offering. The \$3.0 million of expense represents the recovery of the
11 deferred costs over five years. See Uzenski Exhibit A-13, Schedule C5.9.3 for the
12 detailed calculation.

13

14 **Q126. What are the Customer Service regulatory asset impacts of the Company's**
15 **TOD Full Implementation?**

16 A126. The Customer Service operational impacts of the TOU Full Implementation include
17 resource requirements to handle an estimated incremental 430K additional calls in
18 the Contact Center, and an additional 250K of billing exceptions. The one-time \$5.2
19 million incremental costs in Customer Service related to these initiatives are shown
20 on Exhibit A-13, Schedule C5.9.2, Line 11. The Customer Service IT related costs
21 of \$2.5 million are shown on Exhibit A-13, Schedule C5.9.2, Line 9.

22

23 **Q127. Does this complete your direct testimony?**

24 A127. Yes, it does.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of)
DTE ELECTRIC COMPANY)
for authority to increase its rates, amend)
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

HABEEB J. MAROUN

DTE ELECTRIC COMPANY

QUALIFICATIONS AND REVISED DIRECT TESTIMONY OF HABEEB J. MAROUN

Line

No.

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

2 A1. My name is Habeeb J. Maroun (he/him/his). My business address is One Energy
3 Plaza, Detroit, Michigan, 48226. I am employed by DTE Energy Corporate
4 Services, LLC (DTE Energy or DTE) as a Regulatory Strategy Consultant in the
5 Revenue Requirements Department of the Regulatory Affairs Organization.

6

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

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

9

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

11 A3. I received a Bachelor of Science Degree in Mechanical Engineering from the
12 University of Michigan in 2001, a Master's in Finance from Walsh College in 2009,
13 and a Master's in Business Administration from the University of Michigan in
14 2015.

15

16 **Q4. Have you completed any seminars or other training courses?**

17 A4. Yes. I attended utility financing and ratemaking coursework taught by Excidian,
18 LLC. I completed cost of service and utility pricing courses taught by EUCI. I also
19 completed the Ratemaking program at the Institute of Public Utilities at Michigan
20 State University.

21

22 **Q5. What is your work experience?**

23 A5. From 2002 to 2004, I was employed by Lear Corporation and participated in their
24 engineering rotational program. After program completion, I accepted a position
25 in product engineering where I managed several vehicle programs. In 2005, I left

Line
No.

1 Lear to pursue a role as an independent consultant managing procurement for an
2 international glass distributor. In 2009, I assumed additional responsibilities
3 leading the client's expansion from distribution to fabrication. In 2015, I concluded
4 this work to finish my MBA and begin a summer internship with DTE Energy in
5 their Corporate Development group. In this role, I developed revenue requirement
6 models and scenarios. I joined DTE Energy full-time in 2016 as a Senior Strategist
7 within DTE Electric, including roles within the Business Planning and
8 Development and Fossil Generation organizations, where I performed financial
9 analysis, strategic planning, and provided rate case support. In 2019, I accepted a
10 position in Regulatory Affairs as a Principal Financial Analyst in their Revenue
11 Requirement group and was promoted to Regulatory Strategy Consultant in 2022.

12

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

14 A6. As a Regulatory Strategy Consultant for Revenue Requirements within DTE
15 Energy's Regulatory Affairs organization, my responsibilities include the
16 preparation of revenue requirements, cost of service and rate design studies for
17 regulatory filings, along with regulatory analysis and research.

18

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

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

22 U-20484 DTE Electric's 2018 Renewable Energy Plan Reconciliation

23 U-20642 DTE Gas's 2019 Rate Case

24 U-20837 DTE Electric's 2020 Revised AMI Opt-Out Program

25 U-20940 DTE Gas's 2021 Rate Case

Line
No.

1 U-20836 DTE Electric 2022 Rate Case
2 U-21322 DTE Electric & DTE Gas 2024-2025 EWR Plan
3 U-21297 DTE Electric 2023 Rate Case
4

5 **Purpose of Testimony**

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

7 A8. The purpose of my testimony is to present Unbundled Cost of Service (UCOS)
8 Studies for DTE Electric's projected test year ending December 31, 2025. I also
9 provide an Alternate Cost of Service Study with DC Fast Charging (Alternate
10 COSS with DCFC) as a separate class, as required by the Commission in their order
11 on December 1, 2023 in Case No. U-21297. Finally, I support revenue requirement
12 calculations for: (1) customer-related costs, (2) capacity charge by customer class,
13 and (3) Infrastructure Recovery Mechanism (IRM) by voltage class.
14

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

16 A9. Yes. I am supporting the following exhibits:
17

18	<u>Exhibit</u>	<u>Schedule</u>	<u>Description</u>
19	A-16	F1.1	UCOS, Production by Customer Class,
20			TME December 31, 2025
21	A-16	F1.2	UCOS, Distribution by Voltage Class,
22			TME December 31, 2025
23	A-16	F1.3	Functionalization and Allocation Overview
24	A-16	F1.4	Customer Charges by Voltage Class

Line
No.

1 A-16 F1.5 Revised Capacity Charge Revenue Requirement by Customer
2 Class
3 A-16 F1.6 *Alternate COSS with EV DCFC*, Production by
4 Customer Class, TME December 31, 2025
5 A-16 F1.7 *Alternate COSS with EV DCFC*, Distribution by
6 Voltage Class, TME December 31, 2025
7 A-16 F1.8 *Alternate COSS with EV DCFC*, Capacity Charge
8 Revenue Requirement by Customer Class
9 A-33 X6 IRM Distribution Operations - Revenue
10 Requirement by Voltage Class
11

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

13 A10. Yes, they were.
14

15 **Q11. Can you provide an overview of your testimony and recommendations in this**
16 **proceeding?**

17 A11. Below is a summary of my testimony and recommendations:
18

19 **Table 1. Summary of Allocation Methodologies in UCOS**

Cost Type	Proposed Method
Production Plant	4CP 75-0-25
Transmission O&M	12CP 100-0-0
Fuel	12CP 10-0-90
Distribution	Various (by voltage class)
Customer-related	Various; uncollectibles by total revenue

20

21 • I performed forecast test year UCOS studies that apply the allocation
22 methodologies summarized in Table 1, where CP = Coincident Peak, 12

Line
No.

- 1 represents an average of twelve months and 4 represents
2 an average of the four summer months, June through September;
- 3 • The proposed allocation methods for production plant, transmission O&M, fuel
4 and distribution reflect the methods approved in Case No. U-21297;
 - 5 • The proposed allocation of customer-related cost is consistent with past
6 practice. Uncollectibles are allocated to classes based on total revenue;
 - 7 • Customer-related distribution costs are calculated using the “Staff” method as
8 approved by the Commission in Case No. U-21297;
 - 9 • Allocation methods for electric vehicle program costs and demand-related
10 distribution plant-related costs for the secondary voltage level are the same as
11 those approved by the Commission in their order in Case No. U-21297;
 - 12 • Capacity related Power Supply Costs are calculated by reducing total
13 Production Cost of Service for fuel costs, variable O&M, Midwest Energy
14 Resource Company (MERC) and non-capacity power supply costs as approved
15 by the Commission in their order in Case No. U-21297.

16

17 **Q12. How is your testimony organized?**

18 A12. My testimony consists of the following six parts:

19 Part I – Forecast Unbundled Cost of Service Studies

20 Part II – Cost Allocation Methods

21 Part III – Customer Charge Costs

22 Part IV – Capacity Charge Revenue Requirement and SRM Capacity Charge

23 Part V – IRM Distribution Revenue Requirement by Voltage Class

24 Part VI – Alternate Cost of Service Study with DCFC Class

25

Line
No.

1 **Part I: Forecast Unbundled Cost of Service Studies**

2 **Q13. What is a fully allocated embedded UCOS?**

3 A13. A UCOS allocates all items of utility property and cost to determine the fully
4 allocated embedded cost of service for each consolidated customer class of service
5 and shows each customer class's share of costs by major function (Power Supply
6 and Distribution).

7
8 **Q14. What is the objective of a UCOS?**

9 A14. The objective of a UCOS is to apportion all costs required to serve customers
10 among each customer class in a fair and equitable manner. This is defined as that
11 allocation of costs which best reflects the engineering and operating characteristics
12 of the electric utility system and generally results in the costs of the system being
13 allocated to those who caused the costs to be incurred.

14
15 **Q15. What process steps are typically performed in developing a UCOS?**

16 A15. The typical process to develop a UCOS consists of three steps: functionalization,
17 classification, and allocation. Functionalization assigns all costs to the major
18 functions, i.e., Power Supply and Distribution. Classification divides these costs
19 into customer-related costs, demand-related costs, and energy-related costs. The
20 sum of these three types of costs within a given class is the cost to serve that class.
21 The last step, allocation, apportions the cost classifications to the respective
22 customer classes based upon each class's responsibility for the incurrence of these
23 costs.

24
25 **Q16. What functions did you use in the cost studies?**

Line
No.

1 A16. The major utility functions used in the cost studies are Power Supply (Generation
2 and Transmission) and Distribution. Power Supply includes costs associated with
3 the Company's generating plants, fuel, purchased power and the expense associated
4 with transmission services provided to DTE Electric by the Midcontinent
5 Independent System Operator (MISO) and the International Transmission
6 Company (ITC). Distribution includes the costs associated with the Company's
7 distribution system that generally operates at voltages of 40 kV and below and
8 includes customer service costs.

9

10 **Q17. How does the UCOS functionalize DTE Electric's costs?**

11 A17. On Exhibit A-16, Schedule F1.3 page 1 titled "Functionalization and Allocation
12 Overview", I present an overview of the approach I used to functionalize the
13 Company's costs. The MPSC Uniform System of Accounts (USofA) governs
14 utility accounting for ratemaking purposes and serves as the basis for
15 functionalizing direct costs. For example, the USofA requires utilities to record
16 generating plant costs in accounts 310 through 359 and the associated operation
17 and maintenance (O&M) expense in accounts 500 through 557. These costs are
18 directly assigned to the power supply function. Similarly, the USofA requires
19 utilities to record distribution plant costs in accounts 360 through 373 and O&M
20 costs in accounts 580 through 598 that are directly assigned to the distribution
21 function.

22

23 The O&M cost in accounts associated with providing customer service are directly
24 assigned to distribution because they apply whether a customer receives power
25 supply from DTE Electric or an alternative electric supplier (AES). Because DTE

Line
No.

1 Electric has divested its transmission plant, all that remains in the USofA's accounts
2 designated for transmission are the plant costs associated with generator step-up
3 transformers. These costs are directly assigned to power supply. In addition, power
4 supply includes the expense charged to account 565, "Transmission of Electricity
5 by Others" including MISO charges. The property tax associated with production
6 plant is directly assigned to power supply based on tax information provided by the
7 Company's Property Tax Department. A share of the property tax associated with
8 general and intangible plant is allocated to power supply in proportion to the power
9 supply-related general and intangible plant and the remaining balance is assigned
10 to distribution. Indirect costs are comprised of general and intangible plant costs
11 recorded in accounts 303 and 389 through 399, Administrative and General (A&G)
12 expense in accounts 920 through 935, taxes, and working capital. The cost study
13 also includes a credit for miscellaneous revenue, which is applied to the appropriate
14 functional component based on a combination of direct assignment and allocation.

15

16 **Q18. How did the Company functionalize General and Intangible (G&I) plant in**
17 **the Forecast UCOS?**

18 A18. The Forecast UCOS relies on the G&I direct assignment study utilized in Case No.
19 U-21297.

20

21 **Q19. How are the remaining indirect costs and miscellaneous revenues**
22 **functionalized in the Forecast UCOS?**

23 A19. A&G expense is functionalized using the direct labor cost. Working capital is
24 functionalized using allocators appropriate to each of the asset and liability line
25 items. For example, fuel inventory is directly assigned to power supply and

Line
No.

1 accounts receivable is functionalized based on net plant. Miscellaneous revenue is
2 functionalized using a combination of direct assignment and allocation.

3

4 **Q20. What is shown on pages 2 to 28 of Exhibit A-16, Schedule F1.3?**

5 A20. Pages 2 through 28 of Schedule F1.3, "Functionalization and Allocation Overview"
6 provide a detailed list of the functionalization factors and allocation methodologies
7 used in the development of the UCOS study. The column titled "Func. Factor"
8 identifies the functionalization method applied to the cost or revenue on that
9 specific line. The "Prod Alloc" and "Dist Alloc" columns identify the allocation
10 number being applied, and the "Prod Alloc Description" and "Dist Alloc
11 Description" columns shows a brief description of the allocation method.

12

13 **Q21. How does the Forecast UCOS allocate costs to the various customer classes?**

14 A21. In general, the allocation schedules used for each function are intended to reflect
15 the load that utilizes the infrastructure associated with that function.

16

17 **Q22. What method was used to allocate production plant-related costs and
18 transmission O&M costs in the Forecast UCOS?**

19 A22. The Forecast UCOS used the 4CP 75-0-25 method of cost allocation for production
20 plant-related costs and 12CP 100-0-0 for transmission O&M costs, which are the
21 same as approved in Case No. U-21297. For plant-related costs, the first
22 component is the average of the 4 monthly coincident peaks weighted 75%, the
23 second component is energy use coincident to the MISO on-peak period weighted
24 0%, and the third component is total energy use weighted 25%, i.e., 4CP 75-0-25.
25 For transmission O&M, the first component is the average of the 12 monthly

Line
No.

1 coincident peaks weighted 100%, the second component is energy use coincident
2 to the MISO on-peak period weighted 0%, and the third component is total energy
3 use weighted 0%, i.e., 12CP 100-0-0.

4

5 **Q23. Does the UCOS develop costs for each individual rate schedule?**

6 A23. No, it does not. The allocation process apportions costs to classes of service that
7 are comprised of one or more individual rate schedules.

8

9 **Q24. How are the allocation schedules used in the UCOS developed?**

10 A24. The allocation schedules in the UCOS are either developed external to the UCOS
11 model or internally generated by the UCOS model. The externally developed
12 allocation schedules are based on customer class parameters, such as the number of
13 customers, customer energy use and customer demand, and serve as inputs to the
14 UCOS. The internally generated allocation schedules are calculated within the
15 UCOS model and are based on previously allocated plant investment and/or O&M
16 expense. An example of an internal allocation schedule is schedule 521,
17 "Distribution Plant-In-Service." This schedule reflects the sum of the class
18 allocations of distribution plant in service from each USofA account, some of which
19 are further subdivided by voltage level.

20

21 **Q25. What is the source for the externally developed allocation schedules used in**
22 **the UCOS?**

23 A25. The UCOS contains 16 basic externally developed allocation schedules. Of these
24 16 schedules, 11 are developed and supplied by Company Witness Willis and are
25 described in his testimony. I develop the other five schedules: 1) Schedule 800 is

Line
No.

1 based on the number of customers in each class using data from the Company's
2 billing system, 2) Schedules 370T and 370A are based on the number of meters
3 (traditional and advanced metering infrastructure (AMI), respectively) associated
4 with each class and the approximate average cost of the metering equipment
5 associated with each class, 3) Schedule 370C is used to allocate meter related costs;
6 this is a combination of Schedules 370T and 370A, and 4) Schedule 402, total
7 revenues by class, is an aggregate of the production and distribution present
8 revenues (allocators 400 and 401), which I use to allocate uncollectible expense.

9

10 **Q26. How are Distribution System costs allocated within the UCOS?**

11 A26. The direct distribution costs are allocated based on Schedules 201 - 205. The plant-
12 related costs are allocated on the schedule appropriate to the voltage level at which
13 the equipment operates. Distribution O&M expense is allocated based on the
14 corresponding plant-related cost. For example, overhead lines maintenance
15 expense (account 593) is allocated based on the sum of plant-in-service for poles
16 and fixtures (account 364A), overhead conductors (account 365A), and overhead
17 services (account 369A). The cost of some components within distribution, such
18 as those associated with single customer substations and street-lighting, are directly
19 assigned to the voltage cost of service class.

20

21 **Q27. How are the indirect costs allocated within the UCOS?**

22 A27. As stated in my discussion of functionalization, indirect costs are comprised of
23 general and software plant costs recorded in accounts 303 and 389 through 399,
24 A&G expense in accounts 920 through 935, taxes, and working capital. The
25 functionalized general and software plant costs are allocated based on the

Line
No.

1 corresponding functional plant in service. In other words, the general and software
2 plant costs associated with power supply are allocated based on production plant in
3 service and the general and software costs associated with distribution are allocated
4 based on distribution plant in service. Property taxes are allocated based on the
5 corresponding functional plant in service. The functionalized A&G and payroll
6 taxes are allocated based on the corresponding functional labor ratios. The working
7 capital allocations are driven by the numerous allocators associated with each of
8 the line items that comprise working capital, many of which are the sum of several
9 other lines.

10

11 **Q28. What forecast test year was used for the Forecast UCOS?**

12 A28. The forecast test year is the 12 months ending December 31, 2025.

13

14 **Q29. What is the source of the financial information used to produce the Forecast**
15 **UCOS?**

16 A29. I used the financial information supplied by Company Witness Uzenski.

17

18 **Q30. Do the levels of historic investment for each of the distribution accounts within**
19 **the Cost of Service match the figures as they are typically presented in the**
20 **Company's financial records and Form P-521?**

21 A30. Not entirely. Although the total distribution investment matches the Company's
22 financial records, the levels of investment for some distribution accounts within the
23 Cost of Service do not match. These accounts do not match because I break out
24 separately the cost of equipment that operates at sub-transmission voltage (24/40
25 kV) and apply allocation methods that reflect the engineering and operating

Line
No.

1 characteristics of the associated equipment and expense. This redistribution of
2 investment to the accounts in which it was classified prior to the Company's
3 reclassification of 24/40 kV from 350 series accounts (Transmission) to 360
4 accounts (Distribution) is necessary to properly allocate the associated costs. A
5 reclassification for accounting purposes does not change the engineering and
6 operating characteristics of the associated equipment and expense.

7
8 **Q31. Why did the Company reclassify the 24/40 kV investment in the first place?**

9 A31. This reclassification was the result of the Order in MPSC Case No. U-11337 and
10 was pursued to comply with FERC Order 888.

11
12 **Q32. What does Exhibit A-16, Schedule F1.1 show?**

13 A32. Schedule F1.1, "Unbundled Cost of Service, Production by Customer Class TME
14 December 31, 2025" summarizes the results of the Year Ended December 31, 2025,
15 UCOS for Production. It shows the production related revenue
16 deficiency/(sufficiency) associated with each consolidated cost of service rate class.
17 This exhibit shows the Company experienced a base production revenue deficiency
18 of \$148.7 million as shown on page 1, line 27, col. (a) of Schedule F1.1. This
19 deficiency includes an additional \$137.5 million revenue deficiency related to the
20 Monroe Regulatory Asset. The revenue deficiency related to the Monroe
21 Regulatory Asset is calculated by Company Witness Vangilder and is reflected on
22 line 10 of Exhibit A-11, Schedule A1. I functionalized the Monroe Regulatory
23 Asset revenue deficiency as production because it consists of production plant costs
24 and allocated it to various customer classes utilizing the same allocator used to
25 allocate production plant costs (4CP 75-0-25).

Line
No.

1

2 **Q33. Can you explain the Rider 10 Tax Gross-Up Adjustment on line 29 of Exhibit**
3 **A-16, Schedule F1.1?**

4 A33. The Rider 10 (R10) tax gross-up adjustment on line 29 of Exhibit A-16, Schedule
5 F1.1 is a calculation that was approved by the Commission on page 298 of the Case
6 No. U-21297 order. While the net impact of this adjustment to total production
7 revenue requirement is zero, it is a necessary step to eliminate the R10
8 administrative charge, as required by the Commission on page 431 of their order in
9 Case No. U-20836. The methodology proposed in the instant case is consistent
10 with the calculation utilized in the rates approved by the Commission in their order
11 in Case No. U-21297.

12

13 **Q34. What does Exhibit A-16, Schedule F1.2 show?**

14 A34. Schedule F1.2, "Unbundled Cost of Service, Distribution by Voltage Class TME
15 December 31, 2025" summarizes the results of the year ending December 31, 2025,
16 UCOS for Distribution. It shows the distribution related revenue
17 deficiency/(sufficiency) associated with each cost of service voltage class. This
18 exhibit shows the Company experienced a base distribution revenue deficiency of
19 \$307.7 million as shown on page 1, line 27, col. (a) of Schedule F1.2. This
20 deficiency includes an additional \$18.8 million revenue deficiency related to the
21 Tree Trim Surge. The revenue deficiency related to the Tree Trim Surge is
22 calculated by Company Witness Vangilder and is reflected on line 9 of Exhibit A-
23 11, Schedule A1. I functionalized the Tree Trim Surge as distribution because it
24 consists of costs included in O&M account 593 (Maintenance of Overhead Lines)

Line
No.

1 and allocated it to various voltage classes using the same allocator used to allocate
2 account 593.

3

4 **Q35. What are the results shown on Exhibit A-16, Schedules F1.1 and F1.2?**

5 A35. The sum of the base revenue deficiencies on line 27 of Schedules F1.1 and F1.2
6 equals \$456.4 million, which matches the total revenue deficiency on Exhibit A-
7 11, Schedule A-1, supported by Company Witness Vangilder. The base revenue
8 deficiency is then adjusted by D13 incremental revenues totaling -\$0.219 million
9 as shown on line 28 of each exhibit (-\$0.278 million F1.1 + \$0.059 million F1.2).
10 to arrive at the total revenue deficiency/(sufficiency) for ratemaking purposes on
11 line 30 and total base revenue requirement on line 31. Lines 30 and 31 of Schedule
12 F1.1 and Schedule F1.2 are used by Company Witnesses Willis and Bellini to
13 calculate rates.

14

15 **Q36. How are revenues from the D13 high-load factor class apportioned to classes?**

16 A36. I used the same allocation methods initially approved by the Commission in their
17 December 20, 2022 order in Case No. U-21163 (which established D13) and also
18 utilized in the rates approved by the Commission in their order in Case No. U-
19 21297.

20

21 Production and distribution present revenues recovered from D13 are allocated to
22 existing cost of service classes based on production billed revenue excluding R10
23 (allocator 400a) and distribution billed revenue (allocator 401) respectively; this is
24 shown on line 3 of Exhibit A-16, Schedules F1.1 and F1.2.

25

Line
No.

1 Incremental production and distribution revenues, which equal the difference
2 between proposed and present D13 revenues, are allocated to existing cost of
3 service classes on line 28 of Exhibit A-16, Schedules F1.1 and F1.2 using the same
4 allocation methods as used to allocate D13 present revenues.

5

6 **Part II: Cost Allocation Methods**

7 **Q37. Are the cost allocation methods used to produce the forecast UCOS consistent**
8 **with the ones approved by the Commission in Case No. U-21297?**

9 A37. Yes.

10

11 **Q38. What allocation methods did you use for the forecast UCOS in this**
12 **proceeding?**

13 A38. I performed UCOS Studies for the forecast test year based on the proposed
14 allocation methods summarized in Table 2. These allocation methods are the same
15 as those approved in Case No. U-21297:

16

17 **Table 2. Summary of Allocation Methodologies in UCOS**

Cost Type	Proposed Method
Production Plant	4CP 75-0-25
Transmission O&M	12CP 100-0-0
Fuel	12CP 10-0-90
Distribution	Various (by voltage class)
Customer-related	Various; uncollectibles by total revenue

18

19 **Q39. What allocation method are you proposing for Production Plant?**

20 A39. I propose to continue using the 4CP 75-0-25 method approved in the Commission's
21 December 1, 2023 order in Case No. U-21297. Further, this method has been
22 approved in the Company's last seven electric rate cases (U-17767, U-18014, U-

Line
No.

1 18255, U-20162, U-20561, U-20836, and U-21297). The Company is not
2 proposing a deviation from the previously approved production plant allocation at
3 this time.

4

5 **Q40. What allocation method are you proposing for Transmission O&M?**

6 A40. The transmission system that serves DTE Electric's service territory is owned by
7 ITC. DTE Electric's share of the cost of providing transmission service to its
8 customers is determined based upon a 12CP load ratio share. Therefore, an
9 allocation basis that relies on the 12CP 100% demand is reflective of cost causation
10 and was utilized in the final rates approved in the Commission's order in Case No.
11 U-21297.

12

13 **Q41. What allocation methodology changes did the Commission adopt in their**
14 **order in Case No. U-21297?**

15 A41. In Case No. U-21297, the Commission adopted in their order the following
16 allocation methodology changes:

- 17 • EV Program Costs (order, pg. 295): functionalized and allocated using present
18 revenues (allocators 400a and 401)
- 19 • Demand-Related Distribution Plant-Related Costs (order, pg. 300): allocated
20 based on non-coincident peak (NCP) demands (allocator 205)
- 21 • Rider 10 Tax Gross-Up Adjustment (order, pg. 297): allocated using production
22 present revenues excluding R10 (allocator 400a)

23

24 **Q42. Did you use the same allocation methodologies in the instant case?**

25 A42. Yes.

Line
No.

1

2 **Q43. What is DTE Electric's allocation methodology for distribution?**

3 A43. The Company uses three allocation bases for distribution: demand, customer, and
4 those based on special studies. Demand based allocators are used for poles, wires,
5 conduit, substations, transformers, and other equipment that comprise the
6 distribution system. Customer based allocators are used for service drops and
7 billing. A special study was utilized to develop the basis for allocating meters. The
8 proposed allocation method selected for distribution allocates distribution by
9 voltage class. Specifically, distribution is broken into residential secondary,
10 commercial secondary, primary, sub-transmission, transmission, and lighting (E-1
11 Street Lighting, D-9 Outdoor Protective Lighting (OPL), and E-2 Traffic Signals).
12 Distribution allocation methods in the instant case are consistent with those
13 approved by the Commission in their December 1, 2023 order in Case No. U-
14 21297.

15

16 **Q44. Why is lighting maintained as a separate class as opposed to being grouped by**
17 **voltage?**

18 A44. Unlike the distribution service for other classes, the lighting class has a significant
19 amount of dedicated infrastructure costs that should be directly assigned.

20

21 **Q45. What determines cost causation for distribution?**

22 A45. For distribution, the parameters used to design and build the system determine cost
23 causation. The principal system design parameters are the geographic area to be
24 covered and the maximum demand placed on the system at a given voltage level.
25 Because rebuilding a circuit is expensive, distribution planning must consider

Line
No.

1 future load growth and reliability. Also, many of the components of the distribution
2 system are standardized to achieve efficiencies. Consequently, circuits initially
3 have extra capacity, but once demand reaches a certain threshold, either the circuit
4 configuration must be changed, or the components replaced with components
5 having greater capacity. To meet reliability criteria, distribution planning engineers
6 sometimes add alternate lines and transformers. This redundancy maximizes, to
7 the degree practical, the Company's ability to maintain service in the face of storms
8 and other outage related events. Because of the need to consider future growth,
9 reliability, and standardized components, the capacity of the system will generally
10 support loads greater than those initially experienced. Therefore, once installed,
11 distribution system costs are generally not affected by increases or decreases in
12 either demand or energy until the circuit limit (demand threshold) is approached.
13 However, when viewed prospectively, distribution system design cost is caused
14 (driven) by the number of customers served and the maximum demand placed on
15 the system at a given voltage level.

16

17 **Q46. How did you produce the UCOS by voltage level?**

18 A46. I used the allocation schedules and distribution revenues by voltage for customers
19 served at voltage levels primary and above developed by Witness Willis. In
20 addition, I performed calculations to break out the UCOS inputs that I prepare by
21 voltage level. I used these inputs to produce the proposed UCOS that allocates and
22 displays costs by voltage level.

23

24 **Q47. How are you proposing to allocate costs associated with uncollectible expense?**

Line
No.

1 A47. The costs associated with uncollectible expense are allocated based on total
2 revenues, as previously discussed. This allocation method is consistent with the
3 methodology utilized in the final rates approved by the Commission in their
4 December 1, 2023 order in Case No. U-21297.

5

6 **Q48. How are you proposing to allocate merchant fees within Account 903?**

7 A48. Consistent with the Company's last rate case, Case No. U-21297, residential
8 merchant fees are directly assigned to the residential secondary class and
9 commercial merchant fees are directly assigned to the commercial secondary class
10 in the Company's UCOS. This methodology ensures that no cross subsidization
11 occurs across cost-of-service rate classes related to merchant fees.

12

13 **Part III: Customer Charge Costs**

14 **Q49. What type of costs are included within distribution?**

15 A49. The Electric Utility Cost Allocation Manual, National Association of Regulatory
16 Utility Commissioners (NARUC Manual) classifies both distribution plant and
17 expenses as being either demand-related, customer-related, or a combination of the
18 two (Electric Utility Cost Allocation Manual, NARUC, January 1992). Chapter 6
19 of the NARUC Manual titled "Classification and Allocation of Distribution Plant"
20 includes Table 6-1 "Classification of Distribution Plant" and Table 6-2
21 "Classification of Distribution Expenses". Within both tables and Chapter 6, the
22 only cost classification types identified are demand and customer; energy is not
23 listed as a basis for classifying any portion of distribution-related cost. The only
24 energy-related costs identified are production-related.

25

Line
No.

1 **Q50. Can you describe Exhibit A-16, Schedule F1.4 “Customer Charges by Voltage**
2 **Class”?**

3 A50. Exhibit A-16, Schedule F1.4 is a one-page exhibit that calculates monthly customer
4 charges for each voltage level, using the “Staff” method approved in the
5 Commission’s December 1, 2023 order in Case No. U-21297. These costs are
6 detailed on Exhibit A-16, Schedule F1.4.

7
8 **Q51. How did you determine which costs to include on Exhibit A-16, Schedule F1.4**
9 **“Customer Charges by Voltage Class”?**

10 A51. I included the same cost items reflected on Staff Exhibit S-6, Schedule F1.4, from
11 Case No. U-21297 supported by Staff Witness Pung. I have reflected all the same
12 line items as Staff Exhibit S-6, Schedule F1.4 from Case No. U-21297, with
13 updated numbers from the proposed UCOS for distribution reflected in the instant
14 case.

15

16 **Part IV: Capacity Charge Revenue Requirement and SRM Capacity Charge**

17 **Q52. What costs have you included in your calculation of capacity revenue**
18 **requirement reflected on Exhibit A-16, Schedule F1.5 Revised?**

19 A52. The capacity revenue requirement includes all Production related costs per Exhibit
20 A-16, Schedule F1.1, except fuel, variable O&M, MERC, and certain purchase
21 power costs explained later in my testimony. This is consistent with the
22 methodology approved in the Order in the Company’s last electric rate case, Case
23 No. U-21297.

24

Line
No.

1 **Q53. Can you describe in more detail the costs reflected on Exhibit A-16, Schedule**
2 **F1.5 Revised?**

3 A53. Line 1 of Exhibit A-16, Schedule F1.5 Revised exactly matches line 31 from
4 Exhibit A-16, Schedule F1.1 (UCOS Production). Line 2 is a reduction to the
5 revenue requirement for fuel included in the Production UCOS. Line 3 is a
6 reduction for MERC revenue requirement, which is calculated on line 9 of page 6
7 of the exhibit. Lines 4 and 5 are a reduction to the revenue requirement for non-
8 capacity related purchased power. Line 6 is a reduction to the revenue requirement
9 for variable O&M. Line 9 is a reduction in revenue requirement for projected
10 energy sales revenue net of fuel-related costs, calculated by Company Witness
11 Burgdorf on Exhibit A-26, Schedule P3. Line 11 is the total capacity charge revenue
12 requirement that I supply to Witnesses Willis and Bellini.

13

14 **Q54. How did you calculate MERC revenue requirement on line 3 of the exhibit?**

15 A54. This calculation is consistent with the methodology utilized in the final SRM
16 capacity charge approved by the Commission in their December 1, 2023 order in
17 Case No. U-21297. This calculation can be found on page 6 of the exhibit. I
18 calculated MERC net plant on lines 1 through 4. I then multiplied net plant by the
19 weighted average cost of capital on line 5 to determine the return on net plant. Line
20 7 represents MERC depreciation expense, and line 8 represents MERC property
21 tax. Lines 6 through 8 are summed to calculate the MERC revenue requirement on
22 line 9.

23

24 **Q55. Did you reduce the capacity charge revenue requirement for any non-capacity**
25 **related purchased power?**

Line
No.

1 A55. Yes. On lines 4 and 5 of Exhibit A-16 Schedule F1.5 Revised, I reduced the
2 capacity charge revenue requirement for non-capacity related purchased power.
3 The reason for this adjustment is that these costs are not capacity-related; rather,
4 these purchase power costs are for energy purchased from MISO for Rider 3 and
5 Rider 10 (line 4) and other energy related purchased power (line 5). For this reason,
6 the \$439.2 million purchased power expense identified on page 1 line 7 of Exhibit
7 A-16, Schedule F1.1 is considered to be all capacity except for the \$39.6 million
8 directly assigned to Rider 10 and \$0.8 million assigned to Rider 3 (which is
9 included with D11) and \$260.8 million of other energy-related costs. The \$40.4
10 million of non-capacity cost is equal to the sum of the R10 MISO Pricing Option
11 costs listed on line 21 of Exhibit A-13, Schedule C4 and Voltage Level Adder costs
12 listed on line 22 of Exhibit A-13, Schedule C4, sponsored by Witness Willis. The
13 \$260.8 million of other energy-related purchased power is the difference between
14 the capacity related purchased power costs of \$138.1 million calculated by Witness
15 Burgdorf on Exhibit A-26, Schedule P3, line 7 and the total remaining purchased
16 power costs of \$398.8 million (\$439.2 million less \$40.4 million directly assigned
17 to D11 and Rider 10).

18

19 **Q56. Did you make any other adjustments?**

20 A56. Yes. I also adjusted for variable O&M on page 1 line 6 of Exhibit A-16, Schedule
21 F1.5 Revised.

22

23 **Q57. What costs did you include on line 6 of Exhibit A-16, Schedule F1.5 Revised**
24 **for variable O&M?**

Line
No.

1 A57. I calculated variable O&M on Exhibit A-16, Schedule F1.5 Revised, page 5. I
2 included the costs in Account 501 (Fuel Handling) and the non-labor portions of
3 Accounts 502 (Steam Expenses), 505 (Electric Operation Expenses), 519 (Coolants
4 and Water), 520 (Steam Expenses), 538 (Electric Maintenance Expenses) and 548
5 (Peaker Expenses).

6

7 **Q58. Why did you only include the non-labor portion in variable O&M for accounts**
8 **other than 501?**

9 A58. The NARUC Manual describes the classification of production plant in Chapter 4.
10 Chapter 4 describes those accounts 502, 505, 519 and 538 should be: Classified
11 between demand and energy based on labor expenses and materials expenses.
12 Labor expenses are considered demand-related, while material expenses are
13 considered energy-related. Therefore, I determined only the material related costs
14 are variable, and that account 548 should be handled in the same manner. On page
15 35 in Chapter 4, the NARUC Manual states:

16

17 *Production plant costs are either fixed or variable. Fixed production*
18 *costs are those revenue requirements associated with generating plant*
19 *owned by the utility, including cost of capital, depreciation, taxes, and*
20 *fixed O&M. Variable costs are fuel costs, purchased power costs and*
21 *some O&M expenses. Fixed production costs vary with capacity*
22 *additions, not with energy produced from given plant capacity, and are*
23 *classified as demand-related. Variable production costs change with*
24 *the amount of energy produced, delivered, or purchased and are*
25 *classified as energy-related.*

26

27 **Q59. Why did you only include the above accounts in variable O&M?**

Line
No.

1 A59. Based on my review of the descriptions of the various production O&M accounts,
2 only the chosen accounts appear to be variable. The descriptions for these accounts
3 include variable material costs such as lubricants, chemicals, and water.
4

5 **Q60. How did you allocate the Capacity Charge revenue requirement to the various**
6 **rate classes on Exhibit A-16 Schedule F1.5 Revised?**

7 A60. I allocate the Capacity Charge revenue requirement to the various rate classes using
8 the 200B (4CP) allocator excluding Rider 10, which is the methodology approved
9 in Case No. U-21297. The values for this allocation schedule are listed on Line 20
10 of pages 1-4 of Exhibit A-16 Schedule F1.5 Revised. Line 23 of Schedule F1.5
11 Revised reflects the amounts allocated to customer classes and is calculated by
12 multiplying line 20 by the total Capacity Charge revenue requirement of \$973.7
13 million on line 11, divided by 100. Line 24 is the Non-Capacity revenue
14 requirement and is the difference between line 23 and the total production revenue
15 requirement on line 25. Line 25, total production revenue requirement, is equal to
16 line 31 of Exhibit A-16, Schedule F1.1.
17

18 **Q61. Can you describe the SRM Capacity Charge calculation shown in the Exhibit?**

19 A61. The SRM capacity charge calculation starts with the capacity revenue requirement
20 on line 11, whose calculation was previously described in my testimony, and the
21 capacity in MW from the Company's 2022 10-K filing shown on line 13. The SRM
22 Capacity Charge per MW-Year is calculated on line 15 by dividing line 11 by line
23 13 and multiplying by 1,000. This SRM Capacity Charge per MW-Day on line 17
24 is then calculated by dividing line 15 by 365 days.
25

Line
No.

1 **Part V: IRM Revenue Requirement**

2 **Q62. What is reflected on Exhibit A-33, Schedule X6?**

3 A62. Exhibit A-33, Schedule X6, is a one-page exhibit that reflects the allocation of the
4 distribution related IRM revenue requirement to the various voltage classes.
5

6 **Q63. What adjustment to the allocation of IRM revenue requirement did the
7 Commission require in their order in Case No. U-21297?**

8 A63. The Commission stated on pg. 290 of their December 1, 2023 order in Case No. U-
9 21297 that allocator 521 proposed by the Company to allocate IRM revenue
10 requirement should be modified to “remove any allocation of IRM costs from
11 transmission level customers.”
12

13 **Q64. Has the Company complied with this requirement in this proceeding?**

14 A64. Yes.
15

16 **Q65. What is shown on Lines 1 and 2 of Exhibit A-33, Schedule X6?**

17 A65. Lines 1 and 2 of Schedule X6 shows the previously approved IRM revenue
18 requirement by voltage class for 2024 and 2025. The amounts exactly match the
19 IRM revenue requirement by voltage class for 2024 and 2025 utilized to calculate
20 the IRM charges approved in the December 1, 2023 order in Case No. U-21297.
21

22 **Q66. How did you allocate the proposed distribution related IRM revenue
23 requirement to the various rate classes for 2026 and 2027 on Exhibit A-33,
24 Schedules X6?**

Line
No.

1 A66. I allocated the proposed distribution related IRM revenue requirement to the
2 voltage classes for years 2026 and 2027 using allocation schedule 521T, a variant
3 of allocator 521 which was modified to exclude transmission. Allocator 521 is
4 calculated in the UCOS, described in Part I above, and is equal to each voltage
5 classes' share of distribution related plant. The basis for using allocator 521T is
6 because the components of the IRM revenue requirement are all plant or plant
7 related. The value of the allocator is listed on line 3 of Schedule X6. Each voltage
8 classes' share is calculated by multiplying the total proposed distribution related
9 IRM revenue requirements listed on column (a), lines 4 (2026) and 5 (2027) on
10 page 1 of Schedule X6 by the allocation percentages on line 3. The proposed IRM
11 revenue requirements listed on column (a) of Schedule X6 are calculated on Exhibit
12 A-33, Schedule X4 by Witness Vangilder.

13

14 **Part VI: Alternate Cost of Service Study**

15 **Q67. Was an alternate cost of service study required as part of the order in Case**
16 **No. U-21297?**

17 A67. Yes. On pages 342 and 373 of the order, the Commission states "DTE Electric shall
18 conduct a separate cost of service study to allocate appropriate costs fast charging
19 and propose rates for this specific class of customer" to be submitted in the
20 Company's next rate case.

21

22 **Q68. How has DTE Electric addressed these order provisions?**

23 A68. I am submitting an Alternate COSS with EV DC Fast Charging (Alternate COSS
24 with EV DCFC) as a separate class, and Company Witness Willis will be
25 calculating the proposed rates for this class.

Line
No.

1

2 **Q69. What exhibits are you providing that summarize the results of the Alternate**
3 **COSS?**

4 A69. The Alternate COSS exhibits with EV DCFC as a separate class are based on
5 exhibits prepared for the Company's main unbundled cost of service study. The
6 following list of exhibits are being provided:

7 1. Exhibit A-16, Schedule F1.6: Alternate COSS with EV DCFC, Production by
8 Customer Class, TME December 31, 2025 (based on Exh A-16, Sch F1.1)

9 2. Exhibit A-16, Schedule F1.7: Alternate COSS with EV DCFC, Distribution by
10 Voltage Class, TME December 31, 2025 (based on Exh A-16, Sch F1.2)

11 3. Exhibit A-16, Schedule F1.8: Alternate COSS with EV DCFC, Capacity
12 Charge Revenue Requirement by Customer Class (based on Exh A-16, Sch
13 F1.5 Revised)

14

15 **Q70. How was the Alternate COSS with DCFC prepared?**

16 A70. After the Company's main UCOS was completed, I created a duplicate version of
17 the model and then modified it so that EV DCFC would be represented as a separate
18 class. Next, I incorporated present revenues, sales, and customer counts based on
19 information provided by Witness Willis. Finally, I updated the allocation schedules
20 also provided by Witness Willis.

21

22 **Q71. Does this complete your direct testimony?**

23 A71. Yes, it does.

CAPACITY CHARGE						
Cost of Service Study						
75-0-25						
PRODUCTION COSTS						
	(a)	(b)	(c)	(d)	(e)	
	Total Electric	Total Residential	Total Commercial Secondary	Total Primary	E-1 St Lgt D9 OPL E-2 Signals	
CAPACITY COSTS DETERMINATION						
1	Net Production Costs Rev. Req. (Exh A-16 Sch F1.1 Line 31)					
	~~Net Production Costs Rev. Req. (Exh A-16 Sch F1.1 Line 29)~~					
2	\$	3,213,177				
		(914,888)				
3						
		(6,463)				
4						
		(40,376)				
5						
		(260,787)				
6						
		(33,569)				
7	\$	1,957,094				
8						
9						
		(983,347)				
10						
11	Capacity Revenue Requirement (Line 7 + Line 9)					
	~~Capacity Revenue Requirement (Line 6 + Line 7)~~					
12	\$	973,747				
13						
		12,277 MW				
14						
15						
		79,315				
16						
17						
		217.30				
18						
19	Allocator					
20		100.0000	51.7411	25.3267	22.8438	0.0884
21						
22	Revenue Requirement					
23	Capacity Revenue Requirement (Line 11 * Line 20/100)					
	~~Capacity Revenue Requirement (Line 8 * Line 9/100)~~					
	\$	973,747	\$ 503,827	\$ 246,618	\$ 222,441	\$ 860
24	Non-Capacity Revenue Requirement (Line 25 less Line 23)					
	~~Non-Capacity Revenue Requirement (Line 12 less Line 10)~~					
		2,239,430	931,965	567,662	729,410	10,393
25	Total Production Revenue Requirement (Exh A-16 Sch F1.1 Line 31)					
	~~Total Production Revenue Requirement (Exh A-16 Sch F1.1 L 27)~~					
	\$	3,213,177	\$ 1,435,793	\$ 814,280	\$ 951,851	\$ 11,253

DTE Electric Company
Capacity Charge Revenue Requirement by Customer Class /
SRM Capacity Charge
(thousands of dollars)

Case No. U-21534
Exhibit: A-16
Schedule: F1.5 Revised
Witness: H. J. Maroun
Page: 2 of 6

[illegible]

		CAPACITY CHARGE					
		<u>Cost of Service Study</u>					
		75-0-25					
		PRODUCTION COSTS					
		(k)	(l)	(m)	(n)	(o)	(p)
		D-11/Other Primary	D-6.2 Primary Schools	D-8 Interrupt Supply	R-1.1/R-1.2 Metal Melt Process Heat	R-10 Interrupt Supply	Total Primary
		<u> </u>	<u> </u>	<u> </u>	<u> </u>	<u> </u>	<u> </u>
		</					

	Allocator						
20	Sch 200B 4 CP Excl R10 (Alloc. 251)	-	-	-			0.0884
	Revenue Requirement						
23	Capacity Revenue Requirement (Line 11 * Line 20/100)						
	~~Capacity Revenue Requirement (Line 8 * Line 9/100)~~	\$ -	\$ -	\$ -	\$		860
24	Non-Capacity Revenue Requirement (Line 25 less Line 23)						
	~~Non-Capacity Revenue Requirement (Line 12 less Line 10)~~	284	1,274	5,733			3,103
25	Total Production Revenue Requirement (Exh A-16 Sch F1.1 Line 31)						
	~~Total Production Revenue Requirement (Exh A-16 Sch F1.1 L 27)~~	\$ 284	\$ 1,274	\$ 5,733	\$		3,963

	(a)	(b)	(c)
	Total O&M	Labor O&M	Variable O&M (a)-(b)
POWER PRODUCTION EXPENSES			
1 501 Fuel Handling 1/	\$ 27,758	\$ -	\$ 27,758
2 502 Steam Expenses 2/	15,236	15,792	\$ -
3 505 Electric Expenses 2/	2,179	3,238	\$ -
4 519 Coolants and Water	2,559	2,251	\$ 308
5 520 Steam Expenses	(11,294)	4,299	\$ -
6 538 Electric Expense	1,116	-	\$ 1,116
7 548 Peaker Expense	4,405	17	4,388
8 TOTAL	\$ 41,959	\$ 25,597	\$ 33,569

1/ Labor O&M deduction in 501 Fuel Handling eliminated per U-20836 Order
2/ Normalized to eliminate negative variable O&M

			(a)
		Source	<u>Amount</u>
MERC			
1	Gross Plant in Service	WP A16 F1 Sch 5	\$ 101,319
2	Less: Accumulated Depreciation	WP A16 F1 Sch 6	(77,907)
3	CWIP	WP A16 F1 Sch 8	<u>156</u>
4	Net Plant	Sum Lines 1 - 3	23,569
5	Weighted Average Cost of Capital	Exh A-14 Sch D1	5.92%
6	Return	Line 4 x Line 5	\$ 1,396
7	Depreciation Expense	WP A16 F1 Sch 7	4,092
8	Property Tax	WP A16 F1 Sch 17	<u>975</u>
9	MERC Revenue Requirement	Sum Lines 6 - 8	<u>\$ 6,463</u>

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)

CAITLIN D. MYERS states that on July 19, 2024, she served a copy of DTE Electric Company's revised Direct Testimony and Exhibits of Witnesses, Shannen M. Hartwick, Allen J. Kryscynski, Habeeb J. Maroun and Aaron Willis and revised Direct Testimony of Witnesses, Margaret E. Guillaumin, Michael J. Hatsios, Pankaj Sharma and Theresa M. Uzenski in the above captioned matter, via electronic mail upon the persons listed on the attached service list.

Caitlin Myers Digitally signed by Caitlin Myers
Date: 2024.07.19 17:09:28 -04'00'

CAITLIN D. MYERS

ADMINISTRATIVE LAW JUDGE

Honorable Sally L. Wallace
Administrative Law Judge Division
7109 West Saginaw Hwy
Lansing, MI 48917
wallaces2@michigan.gov

ABATE

Michael J. Pattwell
Clark Hill PLC
212 E. Cesar E. Chavez Avenue
Lansing, MI 48906
mpattwell@clarkhill.com

Stephen A. Campbell
Clark Hill PLC
500 Woodward Avenue, Suite 3500
Detroit, MI 48226
scampbell@clarkhill.com

ABATE Consultant

Jessica York
gyork@consultbai.com

ADVANCED ENERGY UNITED; ENERGY MICHIGAN, INC.; FOUNDRY ASSOCIATION OF MICHIGAN; INSTITUTE FOR ENERGY INNOVATION; MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL

Laura A. Chappelle
Timothy J. Lundgren
Justin K. Ooms
Potomac Law Group PLLC
120 N. Washington Square, Suite 300
Lansing, MI 48933
tlundgren@potomaclaw.com
jooms@potomaclaw.com

CITIZENS UTILITY BOARD OF MICHIGAN; MICHIGAN ENVIRONMENTAL COUNCIL; NATURAL RESOURCES DEFENSE COUNCIL; SIERRA CLUB

Christopher M. Bzdok
Tracy Jane Andrews
Troposphere Legal
420 East Front Street
Traverse City, MI 49686
chris@tropospherelegal.com
tjandrews@tropospherelegal.com

Breanna Thomas, Legal Assistant
breanna@tropospherelegal.com

CITY OF ANN ARBOR

Valerie J.M. Brader
Rivenoak Law Group P.C.
3331 W. Big Beaver Rd., Suite 109
Troy, MI 48084
valerie@rivenoaklaw.com
ecf@rivenoaklaw.com

Valerie Jackson
Assistant City Attorney
City of Ann Arbor
Guy C. Larcom City Hall
301. E. Huron Street
Ann Arbor, MI 48104
Vjackson@a2gov.org

ELECTRIFY AMERICA, LLC

Jennifer Morante
Gordon Rees Scully Mansukhani
37000 Woodward Avenue, Suite 225
Bloomfield Hills, MI 48304
jmorante@grsm.com

Stephen Bright
Steve.Bright@electrifyamerica.com

**ENVIRONMENTAL LAW AND POLICY
CENTER; ECOLOGY CENTER; UNION OF
CONCERNED SCIENTISTS; VOTE SOLAR**

Daniel Abrams
Nicholas Wallace
Environmental Law & Policy Center
35 E. Wacker Drive, Suite 1600
Chicago, IL 60601
dabrams@elpc.org
nwallace@elpc.org
MPSCDocket@elpc.org

Carolyn Boyce, ELPC Paralegal
Alondra Estrada, ELPC Legal Assistant
cboyce@elpc.org
aestrada@elpc.org

EVGO SERVICES, LLC

Nikhil Vijaykar
Keyes & Fox LLP
580 California Street, 12th Floor
San Francisco, CA 94104
nvijaykar@keyesfox.com

David Nacht
NachtLaw, PC
501 Avis Drive, Suite 3
Ann Arbor, MI 48108
dnacht@nachtlaw.com

Alicia Zaloga, Paralegal
Lindsey Stegall
azaloga@keyesfox.com
Lindsey.Stegall@evgo.com

**GREAT LAKES RENEWABLE ENERGY
ASSOCIATION INC.**

Don L. Keskey
Brian W. Coyer
University Office Place
333 Albert Avenue, Suite 425
East Lansing, MI 48823
donkeskey@publiclawresourcecenter.com
bwcoyer@publiclawresourcecenter.com

**INTERNATIONAL TRANSMISSION
COMPANY**

Richard J. Aaron
Courtney F. Kissel
Olivia R.C.A. Flower
Hannah E. Buzolits
201 Townsend Street, Suite 900
Lansing, MI 48933
RAaron@dykema.com
CKissel@dykema.com
OFlower@dykema.com
HBuzolits@dykema.com

THE KROGER COMPANY

Michael L. Kurtz
Kurt J. Boehm
Jody Kyler Cohn
Boehm, Kurtz & Lowry
36 East Seventh Street, Suite 1510
Cincinnati, OH 45202
mkurtz@BKLawfirm.com
KBoehm@BKLawfirm.com
JKylerCohn@BKLawfirm.com

Kroger Consultant

Justin Bieber
jbieber@energystrat.com

MICHIGAN ATTORNEY GENERAL

Joel King
Assistant Attorney General
ENRA Division
525 W. Ottawa Street, 6th Floor
P.O. Box 30755
Lansing, MI 48909
KingJ38@michigan.gov
ag-enra-spec-lit@michigan.gov

**MICHIGAN CABLE
TELECOMMUNICATIONS ASSOC.;
ZECO SYSTEMS, INC. D/B/A
GREENLOTS**

Sean P. Gallagher
Fraser Trebilcock Davis & Dunlap
124 West Allegan Street, Suite 1000
Lansing, MI 48933
sgallagher@fraserlawfirm.com

Justin Mann, Legal Assistant
jmann@fraserlawfirm.com

**MICHIGAN MUNICIPAL ASSOCIATION
FOR UTILITY ISSUES**

Valerie J.M. Brader
Rivenoak Law Group P.C.
3331 W. Big Beaver Rd., Suite 109
Troy, MI 48084
valerie@rivenoaklaw.com

Linda Hofrichter
Rick Bunch
lhd@rivenoaklaw.com
rick@mi-maui.org

MPSC STAFF

Heather M.S. Durian
Michael J. Orris
Amit T. Singh
Monica M. Stephens
7109 West Saginaw Hwy, 3rd Floor
Lansing, MI 48917
durianh@michigan.gov
orrism@michigan.gov
singha9@michigan.gov
stephensm11@michigan.gov

Lori Mayabb
MPSC Staff Case Coordinator
mayabbl@michigan.gov

SOULARDARITY; WE WANT GREEN, TOO

Mark Templeton
Amanda Urban
Jacob Schuhardt
Sam Heppell
University of Chicago Law School
Abrams Environmental Law Clinic
6020 South University Avenue
Chicago, IL 60637
templeton@uchicago.edu
t-9aurba@lawclinics.uchicago.edu
jschuhardt@uchicago.edu
heppell@uchicago.edu

Madison S. Wilson, Legal Assistant
madisonswilson@uchicago.edu

UTILITY WORKERS LOCAL 223

Ben King
3950 W. 11 Mile Road
Berkley, MI 48072
bking@michworkerlaw.com

WAL-MART

Melissa M. Horne
Higgins, Cavanagh & Cooney, LLP
10 Dorrance Street, 4th Floor
Providence, RI 02903
mhorne@hcc-law.com